NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Glossary of Terms Used in NERC Reliability Standards

Updated October 19, 2012

Introduction:

This Glossary lists each term that was defined for use in one or more of NERC's continent-wide or Regional Reliability Standards and adopted by the NERC Board of Trustees from February 8, 2005 through October 19, 2012.

This reference is divided into two sections, and each section is organized in alphabetical order. The first section identifies all terms that have been adopted by the NERC Board of Trustees for use in continent-wide standards; the second section identifies all terms that have been adopted by the NERC Board of Trustees for use in regional standards. (WECC, NPCC and Reliability*First* are the only Regions that have definitions approved by the NERC Board of Trustees. If other Regions develop definitions for approved Regional Standards using a NERC-approved standards development process, those definitions will be added to the Regional Definitions section of this glossary.)

Most of the terms identified in this glossary were adopted as part of the development of NERC's initial set of reliability standards, called the "Version 0" standards. Subsequent to the development of Version 0 standards, new definitions have been developed and approved following NERC's Reliability Standards Development Process, and added to this glossary following board adoption, with the "FERC approved" date added following a final Order approving the definition.

Immediately under each term is a link to the archive for the development of that term.

Definitions that have been adopted by the NERC Board of Trustees but have not been approved by FERC, or FERC has not approved but has directed be modified, are shaded in blue. Definitions that have been remanded or retired are shaded in orange.

Any comments regarding this glossary should be reported to the following: sarcomm@nerc.com with "Glossary Comment" in the subject line.

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Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Adequacy [Archive]		2/8/2005	3/16/2007	The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adjacent Balancing Authority [Archive]		2/8/2005	3/16/2007	A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact [Archive]		2/7/2006	3/16/2007	The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.
Adverse Reliability Impact [Archive]		8/4/2011		The impact of an event that results in Bulk Electric System instability or Cascading.
After the Fact [Archive]	ATF	10/29/2008	12/17/2009	A time classification assigned to an RFI when the submittal time is greater than one hour after the start time of the RFI.
Agreement [Archive]		2/8/2005	3/16/2007	A contract or arrangement, either written or verbal and sometimes enforceable by law.
Altitude Correction Factor [Archive]		2/7/2006	3/16/2007	A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Ancillary Service [Archive]		2/8/2005	3/16/2007	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (*From FERC order 888-A.*)
Anti-Aliasing Filter [Archive]		2/8/2005	3/16/2007	An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error [Archive]	ACE	2/8/2005	3/16/2007	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.
Area Interchange Methodology [Archive]		08/22/2008	11/24/2009	The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.
Arranged Interchange [Archive]		5/2/2006	3/16/2007	The state where the Interchange Authority has received the Interchange information (initial or revised).
Automatic Generation Control [Archive]	AGC	2/8/2005	3/16/2007	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Available Flowgate Capability [Archive]	AFC	08/22/2008	11/24/2009	A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.
Available Transfer Capability [Archive]	ATC	2/8/2005	3/16/2007	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.
Available Transfer Capability [Archive]	ATC	08/22/2008	11/24/2009	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.
Available Transfer Capability Implementation Document [Archive]	ATCID	08/22/2008	11/24/2009	A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
ATC Path [Archive]		08/22/2008	Not approved; Modification directed 11/24/09	Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path[1].

[1] See 18 CFR 37.6(b)(1)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Balancing Authority [Archive]	BA	2/8/2005	3/16/2007	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area [Archive]		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
Base Load [Archive]		2/8/2005	3/16/2007	The minimum amount of electric power delivered or required over a given period at a constant rate.
Blackstart Capability Plan [Archive]		2/8/2005 Will be retired when EOP-005-2 becomes enforceable on (7/1/13)	3/16/2007	A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Blackstart Resource [Archive]		8/5/2009	3/17/11	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.
Block Dispatch [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).
Bulk Electric System [Archive]	BES	2/8/2005	3/16/2007	As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Burden [Archive]		2/8/2005	3/16/2007	Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
Business Practices [Archive]		8/22/2008	Not approved; Modification directed 11/24/09	Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices.
Bus-tie Breaker [Archive]		8/4/2011		A circuit breaker that is positioned to connect two individual substation bus configurations.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Capacity Benefit Margin [Archive]	CBM	2/8/2005	3/16/2007	The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.
Capacity Benefit Margin Implementation Document [Archive]	CBMID	11/13/2008	11/24/2009	A document that describes the implementation of a Capacity Benefit Margin methodology.
Capacity Emergency [Archive]		2/8/2005	3/16/2007	A capacity emergency exists when a Balancing Authority Area's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
Cascading [Archive]		2/8/2005	3/16/2007	The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Cascading Outages [Archive]		11/1/2006 Withdrawn 2/12/2008	FERC Remanded 12/27/2007	~~The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre-determined area.~~
Clock Hour [Archive]		2/8/2005	3/16/2007	The 60-minute period ending at :00. All surveys, measurements, and reports are based on Clock Hour periods unless specifically noted.
Cogeneration [Archive]		2/8/2005	3/16/2007	Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
Compliance Monitor [Archive]		2/8/2005	3/16/2007	The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
Confirmed Interchange [Archive]		5/2/2006	3/16/2007	The state where the Interchange Authority has verified the Arranged Interchange.
Congestion Management Report [Archive]		2/8/2005	3/16/2007	A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.
Consequential Load Loss [Archive]		8/4/2011		All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Constrained Facility [Archive]		2/8/2005	3/16/2007	A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.
Contingency [Archive]		2/8/2005	3/16/2007	The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Contingency Reserve [Archive]		2/8/2005	3/16/2007	The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.
Contract Path [Archive]		2/8/2005	3/16/2007	An agreed upon electrical path for the continuous flow of electrical power between the parties of an Interchange Transaction.
Control Performance Standard [Archive]	CPS	2/8/2005	3/16/2007	The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.
Corrective Action Plan [Archive]		2/7/2006	3/16/2007	A list of actions and an associated timetable for implementation to remedy a specific problem.
Cranking Path [Archive]		5/2/2006	3/16/2007	A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.
Critical Assets [Archive]		5/2/2006	1/18/2008	Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Critical Cyber Assets [Archive]		5/2/2006	1/18/2008	Cyber Assets essential to the reliable operation of Critical Assets.
Curtailment [Archive]		2/8/2005	3/16/2007	A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.
Curtailment Threshold [Archive]		2/8/2005	3/16/2007	The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility constraint.
Cyber Assets [Archive]		5/2/2006	1/18/2008	Programmable electronic devices and communication networks including hardware, software, and data.
Cyber Security Incident [Archive]		5/2/2006	1/18/2008	Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Delayed Fault Clearing [Archive]		11/1/2006	12/27/2007	Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.
Demand [Archive]		2/8/2005	3/16/2007	1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Demand-Side Management [Archive]	DSM	2/8/2005	3/16/2007	The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.
Direct Control Load Management [Archive]	DCLM	2/8/2005	3/16/2007	Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.
Dispatch Order [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.
Dispersed Load by Substations [Archive]		2/8/2005	3/16/2007	Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.
Distribution Factor [Archive]	DF	2/8/2005	3/16/2007	The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Distribution Provider [Archive]	DP	2/8/2005	3/16/2007	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Disturbance [Archive]		2/8/2005	3/16/2007	1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.
Disturbance Control Standard [Archive]	DCS	2/8/2005	3/16/2007	The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Disturbance Monitoring Equipment [Archive]	DME	8/2/2006	3/16/2007	Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders[2]: • Sequence of event recorders which record equipment response to the event • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays. • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions
Dynamic Interchange Schedule or Dynamic Schedule [Archive]		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.
Dynamic Transfer [Archive]		2/8/2005	3/16/2007	The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.

[2] Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Economic Dispatch [Archive]		2/8/2005	3/16/2007	The allocation of demand to individual generating units on line to effect the most economical production of electricity.
Electrical Energy [Archive]		2/8/2005	3/16/2007	The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
Electronic Security Perimeter [Archive]	ESP	5/2/2006	1/18/2008	The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.
Element [Archive]		2/8/2005	3/16/2007	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.
Emergency or BES Emergency [Archive]		2/8/2005	3/16/2007	Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.
Emergency Rating [Archive]		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.
Emergency Request for Interchange [Archive]	Emergency RFI	10/29/2008	12/17/2009	Request for Interchange to be initiated for Emergency or Energy Emergency conditions.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Energy Emergency [Archive]		2/8/2005	3/16/2007	A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers' expected energy requirements.
Equipment Rating [Archive]		2/7/2006	3/16/2007	The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.
Existing Transmission Commitments [Archive]	ETC	08/22/2008	11/24/2009	Committed uses of a Transmission Service Provider's Transmission system considered when determining ATC or AFC.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Facility [Archive]		2/7/2006	3/16/2007	A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)
Facility Rating [Archive]		2/8/2005	3/16/2007	The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Fault [Archive]		2/8/2005	3/16/2007	An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Fire Risk [Archive]		2/7/2006	3/16/2007	The likelihood that a fire will ignite or spread in a particular geographic area.
Firm Demand [Archive]		2/8/2005	3/16/2007	That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Transmission Service [Archive]		2/8/2005	3/16/2007	The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Flashover [Archive]		2/7/2006	3/16/2007	An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.
Flowgate [Archive]		2/8/2005	3/16/2007	A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Flowgate [Archive]		08/22/2008	11/24/2009	1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.
Flowgate Methodology [Archive]		08/22/2008	11/24/2009	The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).
Forced Outage [Archive]		2/8/2005	3/16/2007	1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.
Frequency Bias [Archive]		2/8/2005	3/16/2007	A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Bias Setting [Archive]		2/8/2005	3/16/2007	A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.
Frequency Deviation [Archive]		2/8/2005	3/16/2007	A change in Interconnection frequency.
Frequency Error [Archive]		2/8/2005	3/16/2007	The difference between the actual and scheduled frequency. ($F_A - F_S$)
Frequency Regulation [Archive]		2/8/2005	3/16/2007	The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.
Frequency Response [Archive]		2/8/2005	3/16/2007	(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Generator Operator [Archive]	GOP	2/8/2005	3/16/2007	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner [Archive]	GO	2/8/2005	3/16/2007	Entity that owns and maintains generating units.
Generator Shift Factor [Archive]	GSF	2/8/2005	3/16/2007	A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.
Generator-to-Load Distribution Factor [Archive]	GLDF	2/8/2005	3/16/2007	The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.
Generation Capability Import Requirement [Archive]	GCIR	11/13/2008	11/24/2009	The amount of generation capability from external sources identified by a Load-Serving Entity (LSE) or Resource Planner (RP) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.
Host Balancing Authority [Archive]		2/8/2005	3/16/2007	1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries. 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.
Hourly Value [Archive]		2/8/2005	3/16/2007	Data measured on a Clock Hour basis.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Implemented Interchange [Archive]		5/2/2006	3/16/2007	The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation.
Inadvertent Interchange [Archive]		2/8/2005	3/16/2007	The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. ($I_A - I_S$)
Independent Power Producer [Archive]	IPP	2/8/2005	3/16/2007	Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.
Institute of Electrical and Electronics Engineers, Inc. [Archive]	IEEE	2/7/2006	3/16/2007	
Interchange [Archive]		5/2/2006	3/16/2007	Energy transfers that cross Balancing Authority boundaries.
Interchange Authority [Archive]	IA	5/2/2006	3/16/2007	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interchange Distribution Calculator [Archive]	IDC	2/8/2005	3/16/2007	The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.
Interchange Schedule [Archive]		2/8/2005	3/16/2007	An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.
Interchange Transaction [Archive]		2/8/2005	3/16/2007	An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.
Interchange Transaction Tag or Tag [Archive]		2/8/2005	3/16/2007	The details of an Interchange Transaction required for its physical implementation.
Interconnected Operations Service [Archive]		2/8/2005	3/16/2007	A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.
Interconnection [Archive]		2/8/2005	3/16/2007	When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interconnection Reliability Operating Limit [Archive]	IROL	2/8/2005	3/16/2007 Retired 12/27/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.
Interconnection Reliability Operating Limit [Archive]	IROL	11/1/2006	12/27/2007	A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages[3] that adversely impact the reliability of the Bulk Electric System.
Interconnection Reliability Operating Limit T_v [Archive]	IROL T_v	11/1/2006	12/27/2007	The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes.
Intermediate Balancing Authority [Archive]		2/8/2005	3/16/2007	A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities
Interruptible Load or Interruptible Demand [Archive]		11/1/2006	3/16/2007	Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.

[3] On September 13, 2012, FERC issued an Order approving NERC's request to modify the reference to "Cascading Outages" to "Cascading outages" within the definition of IROL due to the fact that the definition of "Cascading Outages" was previously remanded by FERC.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Joint Control [Archive]		2/8/2005	3/16/2007	Automatic Generation Control of jointly owned units by two or more Balancing Authorities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Limiting Element [Archive]		2/8/2005	3/16/2007	The element that is 1.)Either operating at its appropriate rating, or 2,) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.
Load [Archive]		2/8/2005	3/16/2007	An end-use device or customer that receives power from the electric system.
Load Shift Factor [Archive]	LSF	2/8/2005	3/16/2007	A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.
Load-Serving Entity [Archive]	LSE	2/8/2005	3/16/2007	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Long-Term Transmission Planning Horizon [Archive]		8/4/2011		Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.
Market Flow [Archive]		11/4/2010	4/21/2011	The total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve load internal to the market.
Minimum Vegetation Clearance Distance [Archive]	MVCD	11/3/2011		The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Misoperation [Archive]		2/7/2006	3/16/2007	• Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection. • Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone). • Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Native Load [Archive]		2/8/2005	3/16/2007	The end-use customers that the Load-Serving Entity is obligated to serve.
Near-Term Transmission Planning Horizon [Archive]		1/24/2011	11/17/2011	The transmission planning period that covers Year One through five.
Net Actual Interchange [Archive]		2/8/2005	3/16/2007	The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Energy for Load [Archive]		2/8/2005	3/16/2007	Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.
Net Interchange Schedule [Archive]		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Scheduled Interchange [Archive]		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Network Integration Transmission Service [Archive]		2/8/2005	3/16/2007	Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Non-Consequential Load Loss [Archive]		8/4/2011		Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.
Non-Firm Transmission Service [Archive]		2/8/2005	3/16/2007	Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.
Non-Spinning Reserve [Archive]		2/8/2005	3/16/2007	1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.
Normal Clearing [Archive]		11/1/2006	12/27/2007	A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.
Normal Rating [Archive]		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
Nuclear Plant Generator Operator [Archive]		5/2/2007	10/16/2008	Any Generator Operator or Generator Owner that is a Nuclear Plant Licensee responsible for operation of a nuclear facility licensed to produce commercial power.
Nuclear Plant Off-site Power Supply (Off-site Power) [Archive]		5/2/2007	10/16/2008	The electric power supply provided from the electric system to the nuclear power plant distribution system as required per the nuclear power plant license.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Nuclear Plant Licensing Requirements [Archive]	NPLRs	5/2/2007	10/16/2008	Requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for: 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.
Nuclear Plant Interface Requirements [Archive]	NPIRs	5/2/2007	10/16/2008	The requirements based on NPLRs and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Off-Peak [Archive]		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.
On-Peak [Archive]		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.
Open Access Same Time Information Service [Archive]	OASIS	2/8/2005	3/16/2007	An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.
Open Access Transmission Tariff [Archive]	OATT	2/8/2005	3/16/2007	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.
Operating Plan [Archive]		2/7/2006	3/16/2007	A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Procedure [Archive]		2/7/2006	3/16/2007	A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.
Operating Process [Archive]		2/7/2006	3/16/2007	A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.
Operating Reserve [Archive]		2/8/2005	3/16/2007	That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Operating Reserve – Spinning [Archive]		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Reserve – Supplemental [Archive]		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Voltage [Archive]		2/7/2006	3/16/2007	The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.
Operational Planning Analysis [Archive]		10/17/2008	3/17/2011	An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).
Outage Transfer Distribution Factor [Archive]	OTDF	8/22/2008	11/24/2009	In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Overlap Regulation Service [Archive]		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into providing Balancing Authority's AGC/ACE equation.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Participation Factors [Archive]		8/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.
Peak Demand [Archive]		2/8/2005	3/16/2007	1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.
Performance-Reset Period [Archive]		2/7/2006	3/16/2007	The time period that the entity being assessed must operate without any violations to reset the level of non compliance to zero.
Physical Security Perimeter [Archive]	PSP	5/2/2006	1/18/2008	The physical, completely enclosed ("six-wall") border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled.
Planning Assessment [Archive]		8/4/2011		Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.
Planning Authority [Archive]	PA	2/8/2005	3/16/2007	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Planning Coordinator [Archive]	PC	8/22/2008	11/24/2009	See Planning Authority.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Point of Delivery [Archive]	POD	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.
Point of Receipt [Archive]	POR	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.
Point to Point Transmission Service [Archive]	PTP	2/8/2005	3/16/2007	The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.
Postback [Archive]		08/22/2008	Not approved; Modification directed 11/24/09	Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.
Power Transfer Distribution Factor [Archive]	PTDF	08/22/2008	11/24/2009	In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer
Pro Forma Tariff [Archive]		2/8/2005	3/16/2007	Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System [Archive]		2/7/2006	3/17/2007 Will be retired 4/1/2013	Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.
Protection System[4] [Archive] [Implementation Plan]		11/19/2010	2/3/2012	Protection System – • Protective relays which respond to electrical quantities, • Communications systems necessary for correct operation of protective functions • Voltage and current sensing devices providing inputs to protective relays, • Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and • Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.
Pseudo-Tie [Archive]		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.

[4] This term becomes effective on April 1, 2013.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Purchasing-Selling Entity [Archive]	PSE	2/8/2005	3/16/2007	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Ramp Rate or Ramp [Archive]		2/8/2005	3/16/2007	(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.
Rated Electrical Operating Conditions [Archive]		2/7/2006	3/16/2007	The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate
Rating [Archive]		2/8/2005	3/16/2007	The operational limits of a transmission system element under a set of specified conditions.
Rated System Path Methodology [Archive]		08/22/2008	11/24/2009	The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reactive Power [Archive]		2/8/2005	3/16/2007	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power [Archive]		2/8/2005	3/16/2007	The portion of electricity that supplies energy to the load.
Reallocation [Archive]		2/8/2005	3/16/2007	The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.
Real-time [Archive]		2/7/2006	3/16/2007	Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)
Real-time Assessment [Archive]		10/17/2008	3/17/2011	An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data
Receiving Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority importing the Interchange.
Regional Reliability Organization [Archive]	RRO	2/8/2005	3/16/2007	1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. 2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Regional Reliability Plan [Archive]		2/8/2005	3/16/2007	The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished.
Regulating Reserve [Archive]		2/8/2005	3/16/2007	An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
Regulation Service [Archive]		2/8/2005	3/16/2007	The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by NERC for itself and the Balancing Authority for which it is providing the Regulation Service.
Reliability Adjustment RFI [Archive]		10/29/2008	12/17/2009	Request to modify an Implemented Interchange Schedule for reliability purposes.
Reliability Coordinator [Archive]	RC	2/8/2005	3/16/2007	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reliability Coordinator Area [Archive]		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reliability Coordinator Information System [Archive]	RCIS	2/8/2005	3/16/2007	The system that Reliability Coordinators use to post messages and share operating information in real time.
Reliability Directive [Archive]		8/16/2012		A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impact.
Remedial Action Scheme [Archive]	RAS	2/8/2005	3/16/2007	See "Special Protection System"
Reportable Disturbance [Archive]		2/8/2005	3/16/2007	Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.
Request for Interchange [Archive]	RFI	5/2/2006	3/16/2007	A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reserve Sharing Group [Archive]	RSG	2/8/2005	3/16/2007	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.
Resource Planner [Archive]	RP	2/8/2005	3/16/2007	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
Response Rate [Archive]		2/8/2005	3/16/2007	The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
Right-of-Way [Archive]	ROW	2/7/2006	3/16/2007	A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Right-of-Way [Archive]	ROW	11/3/2011		The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.
Right-of-Way [Archive]	ROW	5/9/12		The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Scenario [Archive]		2/7/2006	3/16/2007	Possible event.
Schedule [Archive]		2/8/2005	3/16/2007	(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency [Archive]		2/8/2005	3/16/2007	60.0 Hertz, except during a time correction.
Scheduling Entity [Archive]		2/8/2005	3/16/2007	An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path [Archive]		2/8/2005	3/16/2007	The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority exporting the Interchange.
Sink Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Special Protection System (Remedial Action Scheme) [Archive]	SPS	2/8/2005	3/16/2007	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.
Spinning Reserve [Archive]		2/8/2005	3/16/2007	Unloaded generation that is synchronized and ready to serve additional demand.
Stability [Archive]		2/8/2005	3/16/2007	The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.
Stability Limit [Archive]		2/8/2005	3/16/2007	The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.
Supervisory Control and Data Acquisition [Archive]	SCADA	2/8/2005	3/16/2007	A system of remote control and telemetry used to monitor and control the transmission system.
Supplemental Regulation Service [Archive]		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority's ACE.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Surge [Archive]		2/8/2005	3/16/2007	A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.
Sustained Outage [Archive]		2/7/2006	3/16/2007	The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.
System [Archive]		2/8/2005	3/16/2007	A combination of generation, transmission, and distribution components.
System Operating Limit [Archive]	SOL	2/8/2005	3/16/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)
System Operator [Archive]		2/8/2005	3/16/2007	An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Telemetering [Archive]		2/8/2005	3/16/2007	The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.
Thermal Rating [Archive]		2/8/2005	3/16/2007	The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.
Tie Line [Archive]		2/8/2005	3/16/2007	A circuit connecting two Balancing Authority Areas.
Tie Line Bias [Archive]		2/8/2005	3/16/2007	A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.
Time Error [Archive]		2/8/2005	3/16/2007	The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.
Time Error Correction [Archive]		2/8/2005	3/16/2007	An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
TLR Log [Archive]		2/8/2005	3/16/2007	Report required to be filed after every TLR Level 2 or higher in a specified format. The NERC IDC prepares the report for review by the issuing Reliability Coordinator. After approval by the issuing Reliability Coordinator, the report is electronically filed in a public area of the NERC Web site.
Total Flowgate Capability [Archive]	TFC	08/22/2008	11/24/2009	The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.
Total Transfer Capability [Archive]	TTC	2/8/2005	3/16/2007	The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.
Transaction [Archive]		2/8/2005	3/16/2007	See Interchange Transaction.
Transfer Capability [Archive]		2/8/2005	3/16/2007	The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is *not g*enerally equal to the transfer capability from "Area B" to "Area A."

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transfer Distribution Factor [Archive]		2/8/2005	3/16/2007	See Distribution Factor.
Transmission [Archive]		2/8/2005	3/16/2007	An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.
Transmission Constraint [Archive]		2/8/2005	3/16/2007	A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Customer [Archive]		2/8/2005	3/16/2007	1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Line [Archive]		2/7/2006	3/16/2007	A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.
Transmission Operator [Archive]	TOP	2/8/2005	3/16/2007	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transmission Operator Area [Archive]		08/22/2008	11/24/2009	The collection of Transmission assets over which the Transmission Operator is responsible for operating.
Transmission Owner [Archive]	TO	2/8/2005	3/16/2007	The entity that owns and maintains transmission facilities.
Transmission Planner [Archive]	TP	2/8/2005	3/16/2007	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
Transmission Reliability Margin [Archive]	TRM	2/8/2005	3/16/2007	The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.
Transmission Reliability Margin Implementation Document [Archive]	TRMID	08/22/2008	11/24/2009	A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.
Transmission Service [Archive]		2/8/2005	3/16/2007	Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.
Transmission Service Provider [Archive]	TSP	2/8/2005	3/16/2007	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Vegetation [Archive]		2/7/2006	3/16/2007	All plant material, growing or not, living or dead.
Vegetation Inspection [Archive]		2/7/2006	3/16/2007	The systematic examination of a transmission corridor to document vegetation conditions.
Vegetation Inspection [Archive]		11/3/2011		The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.
Vegetation Inspection [Archive]		5/9/12		The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.
Wide Area [Archive]		2/8/2005	3/16/2007	The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.
Year One [Archive]		1/24/2011	11/17/2011	The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

Reliability*First* Regional Definitions

The following definitions were developed for use in Reliability*First* Regional Standards.

RFC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Resource Adequacy [Archive]		08/05/2009	03/17/2011	The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)
Net Internal Demand [Archive]		08/05/2009	03/17/2011	Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Management and Interruptible Demand
Peak Period [Archive]		08/05/2009	03/17/2011	A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur
Wind Generating Station [Archive]		11/03/2011		A collection of wind turbines electrically connected together and injecting energy into the grid at one point, sometimes known as a "Wind Farm."
Year One [Archive]		08/05/2009	03/17/2011	The planning year that begins with the upcoming annual Peak Period

NPCC Regional Definitions

The following definitions were developed for use in NPCC Regional Standards.

NPCC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Current Zero Time [Archive]		11/04/2010	10/20/2011	The time of the final current zero on the last phase to interrupt.
Generating Plant [Archive]		11/04/2010	10/20/2011	One or more generators at a single physical location whereby any single contingency can affect all the generators at that location.

WECC Regional Definitions

The following definitions were developed for use in WECC Regional Standards.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Area Control Error† [Archive]	ACE	3/12/2007	6/8/2007	Means the instantaneous difference between net actual and scheduled interchange, taking into account the effects of Frequency Bias including correction for meter error.
Automatic Generation Control‡ [Archive]	AGC	3/12/2007	6/8/2007	Means equipment that automatically adjusts a Control Area's generation from a central location to maintain its interchange schedule plus Frequency Bias.
Automatic Time Error Correction [Archive]		3/26/2008	5/21/2009	A frequency control automatic action that a Balancing Authority uses to offset its frequency contribution to support the Interconnection's scheduled frequency.
Average Generation‡ [Archive]		3/12/2007	6/8/2007	Means the total MWh generated within the Balancing Authority Operator's Balancing Authority Area during the prior year divided by 8760 hours (8784 hours if the prior year had 366 days).
Business Day‡ [Archive]		3/12/2007	6/8/2007	Means any day other than Saturday, Sunday, or a legal public holiday as designated in section 6103 of title 5, U.S. Code.
Disturbance‡ [Archive]		3/12/2007	6/8/2007	Means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Extraordinary Contingency‡ [Archive]		3/12/2007	6/8/2007	Shall have the meaning set out in Excuse of Performance, section B.4.c. language in section B.4.c: *means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity's reasonable control; provided that prudent industry standards (e.g. maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the "Most Severe Single Contingency" as defined in the WECC Reliability Criteria or any lesser contingency).*
Frequency Bias‡ [Archive]		3/12/2007	6/8/2007	Means a value, usually given in megawatts per 0.1 Hertz, associated with a Control Area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.
Generating Unit Capability‡ [Archive]		3/12/2007	6/8/2007	Means the MVA nameplate rating of a generator.
Non-spinning Reserve‡ [Archive]		3/12/2007	6/8/2007	Means that Operating Reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.
Normal Path Rating‡		3/12/2007	6/8/2007	Is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
[Archive]				is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.
Operating Reserve‡ [Archive]		3/12/2007	6/8/2007	Means that capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. Operating Reserve consists of Spinning Reserve and Nonspinning Reserve.
Operating Transfer Capability Limit‡ [Archive]	OTC	3/12/2007	6/8/2007	Means the maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient criteria as determined by equipment loading capability and acceptable voltage conditions, (c) transient performance criteria, and (d) post-contingency loading and voltage criteria.
Primary Inadvertent Interchange [Archive]		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by the regulating deficiencies of the area (n).
Secondary Inadvertent Interchange [Archive]		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by the regulating deficiencies of area (i).
Spinning Reserve‡ [Archive]		3/12/2007	6/8/2007	Means unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating reserve and Contingency reserve (as each are described in Sections B.a.i and ii).

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
WECC Table 2[†] [Archive]		3/12/2007	6/8/2007	Means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A to this Standard.
Functionally Equivalent Protection System [Archive]	FEPS	10/29/2008	4/21/2011	A Protection System that provides performance as follows: • Each Protection System can detect the same faults within the zone of protection and provide the clearing times and coordination needed to comply with all Reliability Standards. • Each Protection System may have different components and operating characteristics.
Functionally Equivalent RAS [Archive]	FERAS	10/29/2008	4/21/2011	A Remedial Action Scheme ("RAS") that provides the same performance as follows: • Each RAS can detect the same conditions and provide mitigation to comply with all Reliability Standards. • Each RAS may have different components and operating characteristics.
Security-Based Misoperation [Archive]		10/29/2008	4/21/2011	A Misoperation caused by the incorrect operation of a Protection System or RAS. Security is a component of reliability and is the measure of a device's certainty not to operate falsely.
Dependability-Based Misoperation [Archive]		10/29/2008	4/21/2011	Is the absence of a Protection System or RAS operation when intended. Dependability is a component of reliability and is the measure of a device's certainty to operate when required.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Commercial Operation [Archive]		10/29/2008	4/21/2011	Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.
Qualified Transfer Path Curtailment Event [Archive]		2/10/2009	3/17/2011	Each hour that a Transmission Operator calls for Step 4 or higher for one or more consecutive hours (See Attachment 1 IRO-006-WECC-1) during which the curtailment tool is functional.
Relief Requirement [Archive]		2/10/2009	3/17/2011	The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority's Contributing Schedules by the percentages listed in the columns of WECC Unscheduled Flow Mitigation Summary of Actions Table in Attachment 1 WECC IRO-006-WECC-1.
Transfer Distribution Factor [Archive]	TDF	2/10/2009	3/17/2011	The percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented. [See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]
Contributing Schedule [Archive]		2/10/2009	3/17/2011	A Schedule not on the Qualified Transfer Path between a Source Balancing Authority and a Sink Balancing Authority that contributes unscheduled flow across the Qualified Transfer Path.
Qualified Transfer Path [Archive]		2/10/2009	3/17/2011	A transfer path designated by the WECC Operating Committee as being qualified for WECC unscheduled flow mitigation.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Qualified Controllable Device [Archive]		2/10/2009	3/17/2011	A controllable device installed in the Interconnection for controlling energy flow and the WECC Operating Committee has approved using the device for controlling the USF on the Qualified Transfer Paths.

Endnotes

[†] FERC approved the WECC Tier One Reliability Standards in the Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, 119 FERC ¶ 61,260 (June 8, 2007). In that Order, FERC directed WECC to address the inconsistencies between the regional definitions and the NERC Glossary in developing permanent replacement standards. The replacement standards designed to address the shortcomings were filed with FERC in 2009.

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Glossary of Terms

Approved by the Reliability Standards Committee

October 26, 2011

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
Actual Interchange		Metered electric **power** that flows from one entity to another.	D5
Applicable emergency limits		These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitations, etc. **Emergency** limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes. The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system **stability** performance, and should not adversely affect the operation of the **bulk power system**. The limiting condition for equipment loadings should be such that cascading outages will not occur due to operation of protective devices upon the failure of facilities. (Various definitions of equipment **ratings** are found elsewhere in this glossary.)	D1 D7
Area		An **Area** (when capitalized) refers to one of the following: New England, New York, Ontario, Quebec or the Maritimes (New Brunswick, Nova Scotia and Prince Edward Island); or, as the situation requires, area (lower case) may mean a part of a system or more than a single system. Within NPCC, Areas (capitalized) operate as **control areas** as defined by the North American Electric Reliability Council (NERC) (the definition can be found in this glossary).	D1 D7 D8 D12
Area Control Error	**ACE**	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error. (Source: NERC Glossary of Terms)	D2 D5 D8

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Term	Acronym	Definition	Directories that use this term
Automatic Generation Control	**AGC**	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction. (Source: NERC Glossary of Terms)	D2 D5 D8
Basic Minimum Power System		Consists of one or more generating stations, transmission lines, and substations operating in the form of an island for the purpose of initiating the restoration process. The Reliability Coordinator and Transmission Operator shall each identify its area's basic minimum power system(s) within its system restoration plan.	D8
Bipolar		Operation of HVdc with two **poles** of opposite polarity with negligible ground current.	D1
Blackstart Capability		The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering **power** without assistance from the electric system.	D8
Bulk Power System	**BPS**	The interconnected electrical systems within northeastern North America comprised of system **elements** on which **faults** or **disturbances** can have a **significant adverse impact** outside of the **local area.**	D1 D2 D3 D4 D7 D9 D10
Cable		An underground or underwater circuit.	D4 D5 D7 D8

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Term	Acronym	Definition	Directories that use this term
Capacity		The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of **generation**, transmission, or other electrical equipment.	D1 D2 D5 D8
Commutation Failure		A fault in a thyristor valve group where the current transfer from one valve to the next is interrupted.	D4
Component		Refers to components of equipment or protection systems rather than **elements** of a **power** system. See **Element**.	D1 D3 D7
Contingency		An event, usually involving the loss of one or more **elements**, which affects the power system at least momentarily.	D1 D2 D5 D7
Converter		An operative unit comprised of either a rectifier or inverter bridge connected to an ac system through transformers and switching devices with the associated control equipment.	D4
Converter Transformer		A **power** transformer which transfers the energy from the thyristor valves to the connected ac system and vice-versa.	D4
Critical Components		Equipment required for continued and proper operation of a **key facility** in the event of a total loss of grid supply. Critical components include but are not limited to the following: ▪ blackstart generating units; ▪ substation backup power supplies; ▪ control center and telecommunication center backup power supplies and computer systems;	D8

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		▪ control center and telecommunication center computer room HVAC; ▪ telecommunication facilities backup power supplies.	
Declared Capability (of a generator or generating facility)		The facility ratings submitted by the Generator Owner to the respective Transmission Operator as per NERC Standard FAC-009.	D10
Delayed Fault Clearing		Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay. (Source: NERC Glossary of Terms)	D1
Demand		1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer. (Source: NERC Glossary of Terms)	D1 D5
Disturbance		Severe oscillations or severe step changes of current, voltage and/or frequency usually caused by **faults**.	D1 D2 D4 D5 D7
Disturbance Monitoring Equipment	**DME**	Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders2 • Sequence of event recorders which record equipment response to the event; • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective	D4

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Term	Acronym	Definition	Directories that use this term
		relays; • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions (Source: NERC Glossary of Terms)	
Economic Dispatch		The allocation of demand to individual generating units on line to effect the most economical production of electricity. (Source: NERC Glossary of Terms)	D2
Element		Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components. (Source: NERC Glossary of Terms)	D1 D2 D4 D5 D7 D9 D10
Emergency		Any abnormal system condition that requires automatic or manual action to prevent or limit loss of transmission facilities or **generation** supply that could adversely affect the **reliability** of the electric system. NPCC Specific Definition: **Emergency** — An **Emergency** is considered to exist in an Area if **firm load** may have to be shed.	D1 D2 D4 D5 D7
Emergency Regional Reserve Redispatch		The regional coordination of actions to enhance **reliability** among **Areas** in response to a **Regional Reserve Deficiency.**	D5

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
Emergency Regional Reserve Dispatch Energy		Electrical energy that is received and delivered among **Areas** in response to a **Regional Reserve Deficiency** to enhance regional **reliability.**	D5
Emergency Transfer Capability		The amount of **power** transfer allowed between **Areas** or within an **Area** when ope**rating** to meet NPCC **emergency** criteria contingencies [as defined in Directory #1].	D2
Energize		To make a piece of equipment or circuit alive.	D4
Fault		An electrical **short circuit**.	D1 D4 D7
Firm Capacity		Capacity that is as firm as the seller's native **load** unless modified by contract. Associated energy may or may not be taken at option of purchaser. Supporting **reserve** is carried by the seller.	D1
Firm Load		That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions. (Source: Firm Demand defined in NERC Glossary of Terms)	D1 D2
First Contingency Loss		The largest **capacity** outage including any assigned Ten-Minute Reserve which would result from the loss of a single **element.**	D5
Forced Outage		1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure. (Source: NERC Glossary of Terms)	D1
Generation (Electricity)		The process of producing electrical energy from other forms of energy;	D1

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Term	Acronym	Definition	Directories that use this term
		also, the amount of electric energy produced, usually expressed in kilowatthours (kWh) or megawatthours (MWh). Gross Generation — The electrical output at the terminals of the generator, usually expressed in megawatts (MW). Net Generation — Gross generation minus station service or unit service **power** requirements, usually expressed in megawatts (MW).	D2 D4 (Appendix A) D5 D7 (Appendices) D12
Generation Facility		Generating units, which are modeled as a single entity by the Transmission Operator.	D8 D9 D10
Generation Rejection		The process of deliberately removing preselected **generation** from a **power** system, or initiating HVdc power runback, in response to a **contingency** or an abnormal condition in order to maintain the integrity of the system. Synonym: Generator Dropping.	D1 D7
Gross Real Power Capability (of a generator or generating facility)		The maximum megawatt output at the generator terminals, at the normally expected system conditions for that seasonal capability period.	D9
Gross Reactive Power Capability (of a generator or generating facility)		The maximum lagging and leading reactive capability at the generator terminals and at a specified Gross Real Power output for a specific seasonal capability period.	D10
Grounded		Connected to earth or some extended conducting body that serves instead of the earth, whether the connection is intentional or accidental.	D4 D7
Harmonic		A sinusoidal component of a periodic wave or quantity having a frequency that is an integral multiple of the fundamental frequency. Note: For example, a component, the frequency of which is twice the fundamental frequency, is called a second harmonic.	D4
HVdc Link		A high Voltage direct current connection between two **power** systems often	D4

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Term	Acronym	Definition	Directories that use this term
		used to interconnect two asynchronous **power** systems.	
Inadvertent Interchange		The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. (IA – IS) (Source: NERC Glossary of Terms)	D5
Interconnection		When capitalized, any one of the five major electric system networks in North America: Eastern, Western, ERCOT, Québec, and Alaska. When not capitalized, the facilities that connect two systems or **Control Areas**. Additionally, an interconnection refers to the facilities that connect a nonutility generator to a **Control Area** or system.	D1 D2 D5 D8 D12
Interchange		Energy transfers that cross Balancing Authority boundaries. (Source: NERC Glossary of Terms)	D1 (Appendix B) D2 D5
Interchange Schedule		An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction. (Source: NERC Glossary of Terms)	D1 D5
Interface		The specific set of transmission **elements** between two areas or between two areas comprising one or more electrical systems.	D1 (Appendices)
Interruptible Load		Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment. (Source: NERC Glossary of Terms)	D1 (Appendix D) D5
Island		A portion of a **power** system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission	D1 D8

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Term	Acronym	Definition	Directories that use this term
		system **elements.**	D12
Key Facilities		Facilities required to establish a **basic minimum power system** following a system blackout. These facilities are essential to the restoration plan of the **Control Area** and include generating stations having blackstart units and other selected generating stations, transmission **elements** which are part of the **basic minimum power system,** control centers and telecommunication centers and telecommunication facilities which are necessary to support **protection** and control facilities, voice and data between and within control centers and voice and data between control centers and key generating / transmission substations.	D8
Load		An end-use device or customer that receives power from the electric system. (Source: NERC Glossary of Terms)	D1 D2 D3 D4 D5 D7 (Appendices) D8 D9 D10 D12
Load Relief		**Load** reduction accomplished by **voltage reduction** and/or **load shedding**.	D1
Load Shedding		The process of deliberately removing (either manually or automatically) preselected customers' **load** from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.	D2 D3 D4 D12
Local area		An electrically confined or radial portion of the system. The geographic	D1

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.	D4
Maintenance Outage		The removal of equipment from service **availability** to perform work on specific **elements** that can be deferred, but requires the equipment be removed from service before the next planned outage. Typically, a Maintenance Outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.	D1
Net Capacity		The maximum capacity (or effective **rating**), modified for ambient limitations, that a generating unit, **power** plant, or electric system can sustain over a specified period, less the capacity used to supply the **demand** of station service or auxiliary needs.	D1
Net Real Power Capability (of a generator or generating facility)		The Gross Real Power Capability, less the auxiliary real power loads necessary to operate the generator at maximum real power output.	D9
Net Reactive Power Capability (of a generator or generating facility)		The **Gross Reactive Power Capability** adjusted for any applicable losses and auxiliary loads incurred up to the point of interconnection and at a specified Gross Real Power output for a specific seasonal capability period.	D10
Normal Fault Clearing		Fault clearing consistent with correct operation of the **protection system** and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that **protection system.**	D1

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Term	Acronym	Definition	Directories that use this term
Normal (Precontingency) Operating Procedures		Operating procedures that are normally invoked by the **system operator** to alleviate potential facility overloads or other potential system problems in anticipation of a **contingency**.	D1 (Appendix F)
Normal Transfer Capability		The amount of **power** transfer allowed between **Areas** or within an **Area** when operating to meet NPCC normal criteria contingencies [as defined in Directory #1].	D1 D2
Operating Capability		The maximum load carrying ability of generating equipment or other electrical apparatus under specified conditions for a given time interval.	D9
Operating Limit		The maximum value of the most critical system operation parameter(s) which meet(s): (a) pre-**contingency** criteria as determined by equipment loading capability and acceptable voltage conditions; (b) **stability** criteria; (c) post-**contingency** loading and voltage criteria.	D1 (Appendix C) D2 D5
Operating Capacity		The **capacity** claimed for any generating source recognizing any temporary deratings, governor load limits, proven maximum loading rates, starting times and equipment limitations including transmission **operating limits**.	D5
Operating Procedures		A set of policies, practices, or system adjustments that may be automatically or manually implemented by the **system operator** within a specified time frame to maintain the operational integrity of the interconnected electric systems.	D1 D5 D7
Operating Reserve		The sum of **ten-minute** and **thirty-minute reserve**.	D1 D2
Phase Shifting Transformer		A transformer that advances or retards the phase angle relationship of one circuit with respect to another to control **power** flow. Synonyms: Phase angle regulator, phase shifter.	D1 D2 D4
Pilot Protection		A form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line.	D4
Planned Outage		Removing the equipment from service **availability** for inspection and/or general overhaul of one or more major equipment groups. This outage	D1

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		usually is scheduled well in advance.	
Pole (HVdc term)		A rectifier and an inverter, with associated filter banks and control equipment, tied together by a transmission line or bus.	D1
Power		See definitions for Real Power and Reactive Power.	D8
Power Swing		A transient change in the **power** flows on a system, usually of an oscillatory nature.	D1 D4 (Appendix A)
Protected element		The power system **element** protected by the subject **protection system**. Examples: Line, bus, transformer, generator.	D4
Protection		The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.	D1 D2 D3 D4 D7
Protection group		A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups. Notes: (a) Variously identified as Main Protection, Primary Protection, Breaker Failure Protection, Back-Up Protection, Alternate Protection, Secondary Protection, A Protection, B Protection, Group A, Group B, System 1 or System 2. (b) Pilot protection is considered to be one protection group.	D1 D3 D4 D7
Protection System		Element Basis	D1

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Term	Acronym	Definition	Directories that use this term
		One or more protection groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete protection of that **element**. Terminal Basis One or more protection groups, as above, installed at one terminal of a power system **element**, typically a transmission line.	D3 D4 D7
Protective relay		A **relay** that detects a power system **fault** or abnormal condition and initiates appropriate control system action.	D3 D4
Rating		The operational limits of an electric system, facility, or **element** under a set of specified conditions.	D1 D5
Reactive Power		The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVAr).	D1 D2 D10
Real Power		The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).	D1 D2

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Term	Acronym	Definition	Directories that use this term
			D9 D10
Reclosing		Autoreclosing — The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker. Autoreclosing does not include automatic closing of capacitor or reactor circuit breakers. High-speed autoreclosing — The autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle. Manual Reclosing — The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised. Supervision — A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., **synchronism-check**). Synchronism-check — refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.	D1
Regional Reserve Deficiency		When two or more **Areas** are deficient in **ten minute reserve** after all **Area** coordinated actions have been deployed, including acquiring emergency energy and/or capacity but excluding the shedding of firm load.	D5
Relay		An electrical device designed to respond to input conditions in a prescribed	D1

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Term	Acronym	Definition	Directories that use this term
		manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).	D3 D4 D7 D12
Reliability		The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — Adequacy and **Security.** Adequacy — The ability of the electric system to supply the aggregate electrical **demand** and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system **elements**. Security — The ability of the electric system to withstand **disturbances** such as electric **short circuits** or unanticipated loss of system **elements.**	D1 D2 D5 D9 D10
Reportable Events		**System disturbances** involving losses of **load**, **generation** or transmission facilities within NPCC **Control Areas** which equal or exceed the following criteria are reportable events: (1) Actual net **interchange** deviations equal to or greater than 500 MW (Maritime: 300 MW). (2) Loss of **generation** or **load** equal to or greater than 500 MW (Maritime: 300 MW). (3) System frequency deviations equal to or greater than 0.03 Hz (Hydro-Quebec: 0.5 Hz). (System frequency deviations that occur for events outside of the NPCC are reported for analysis of frequency response, but are not included in the reporting for the NERC Disturbance Control Standard.)	D5

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Term	Acronym	Definition	Directories that use this term
Reserve		In normal usage, reserve is the amount of capacity available in excess of the demand	D1 D2 D5
Reserve on Automatic Generation Control (AGC)		That portion of **synchronized reserve** which is under the command of an automatic controller to respond to **load** without need for manual action.	D5
Reserve Requirement		That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area supply adequacy.	D2 D5
Resource		Resource refers to the total contributions provided by supply-side and **demand**-side facilities and/or actions. Supply-side facilities include utility and non-utility **generation** and purchases from neighboring systems. **Demand**-side facilities include measures for reducing **load**, such as conservation, **demand** management, and **interruptible load.**	D1 D2 D5 D8 D9 D10
Scheduled Interchange		The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time. (Source: Net Scheduled Interchange defined in NERC Glossary of Terms)	D5
Second Contingency Loss		The largest **capacity** outage which would result from the loss of a single **element** after allowing for the First Contingency Loss.	D5
Short Circuit		An abnormal connection (including an arc) of relatively low impedance, whether made accidentally or intentionally, between two points of different potential. *Note:* The term **fault** or short-circuit **fault** is used to describe a short circuit.	D4 D7
Short Time Emergency Rating	**STE**	The maximum loading of electrical equipment which can be sustained for 15 minutes based on nominal ambient conditions and recognizing preloading conditions.	D1 (Appendix C)

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Term	Acronym	Definition	Directories that use this term
Significant Adverse Impact		With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from **faults** or **disturbances**, shall be deemed as having **significant adverse impact**: a. instability; • any instability that cannot be demonstrably contained to a well-defined **local area**. • any loss of synchronism of generators that cannot be demonstrably contained to a well-defined **local area** b. unacceptable system dynamic response; • an oscillatory response to a **contingency** that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event. c. unacceptable equipment tripping • tripping of an un-faulted **bulk power system** element (element that has already been classified as **bulk power system**) under planned system configuration due to operation of a **protection system** in response to a stable **power swing** • operation of a Type I or Type II **Special Protection System** in response to a condition for which its operation is not required d. voltage levels in violation of applicable **emergency** limits; e. loadings on transmission facilities in violation of applicable **emergency** limits.	D1 (Appendix E) D5
Single Contingency		A single event, which may result in the loss of one or more **elements.**	D5
Special Protection System	**SPS**	**Special Protection System (SPS)** – A **protection system** designed to detect abnormal system conditions and take corrective action other than the	D1 D3

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Term	Acronym	Definition	Directories that use this term
		isolation of faulted **elements**. Such action may include changes in **load**, **generation**, or system configuration to maintain system **stability**, acceptable voltages or **power** flows. However, the following are not considered **SPS's**: - Automatic underfrequency **load shedding;** - Automatic under voltage **load shedding**, and - Manual or automatic locally controlled shunt devices.	D4 (Appendix A) D7
Stability		The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: NERC Glossary of Tems)	D1 D4
Static Var Compensator	**SVC**	A combination of controlled shunt reactors and switched capacitor banks, used to affect the **reactive power** flow of the system or to regulate the system voltage.	D1 (Appendix G) D2 D4
Synchronize		The process of connecting two previously separated alternating current apparatuses or systems after matching frequency, voltage, phase angles, etc. (e.g., paralleling a generator to the electric system).	D8

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Term	Acronym	Definition	Directories that use this term
Synchronized Reserve		The unused portion of generating capacity which is synchronized to the system and ready to pick up **load** to claimed capacity and capacity which can be made available by curtailing pumping hydro units.	D5
Synchronous Condenser		A synchronous machine which operates without mechanical load to supply or absorb **reactive power** for voltage control purposes.	D2 D10
System Disturbance		An event characterized by one or more of the following phenomena: the loss of **power** system **stability**; cascading outages of circuits; oscillations; abnormal ranges of frequency or voltage or both.	D1 D2 D4 D5 D7
System Operator		An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time. (Source: NERC Glossary of Terms)	D2 D3 D8
Teleprotection		A form of **protection** that uses a communication channel.	D4 D7
Ten-Minute Reserve		The sum of **synchronized** and non-**synchronized reserve** that is fully available in ten minutes.	D1 D5
Thirty-Minute Reserve		The sum of **synchronized** and non-**synchronized reserve** that can be utilized in thirty minutes, excluding capacity assigned to **ten-minute reserve**.	D5
Tie Line		A circuit connecting two Balancing Authority Areas.	D1 D2 (Appendix B) D5
Tie Line Bias		A mode of operation under automatic **generation** control in which the **area control error** is determined by the actual net **interchange** minus the biased	D2

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Term	Acronym	Definition	Directories that use this term
		scheduled net **interchange.**	
Total Transfer Capability	**TTC**	The amount of electric **power** that can be transferred over the interconnected transmission network in a *reliable* manner based on *all* of the following conditions: 1. For the existing or planned system configuration, and with **normal** (**precontingency**) **operating procedures** in effect, all facility loadings are within normal **ratings** and all voltages are within normal limits. 2. The electric systems are capable of absorbing the dynamic **power swings**, and remaining stable, following a **disturbance** that results in the loss of any single electric system **element**, such as a transmission line, transformer, or generating unit. 3. After the dynamic **power swings** subside following a **disturbance** that results in the loss of any single electric system **element** as described in 2 above, and after the operation of any automatic operating systems, but before any post-**contingency** operator-initiated system adjustments are implemented, all transmission facility loadings are within **emergency ratings** and all voltages are within **emergency** limits 4. With reference to condition 1 above, in the case where precontingency facility loadings reach normal thermal **ratings** at a transfer level below that at which any first **contingency** transfer limits are reached, the transfer capability is defined as that transfer level at which such normal **ratings** are reached. 5. In some cases, individual system, **power pool,** subregional, or Regional planning criteria or guides may require consideration of specified multiple contingencies, such as the outage of transmission circuits using common towers or rights-of-way, in the determination of	D5

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Term	Acronym	Definition	Directories that use this term
		transfer capability limits. If the resulting transfer limits for these multiple **contingencies** are more restrictive than the single contingency considerations described above, the more restrictive **reliability** criteria or guides must be observed.	
Transfer Capability		The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is not generally equal to the transfer capability from "Area B" to "Area A." (Source: NERC Glossary of Terms)	D1 D2 D5
Transient Stability		The ability of an electric system to maintain synchronism between its parts when subjected to a **disturbance** and to regain a state of equilibrium following that disturbance.	D1
Verified Capability (of a generator or generating facility)		The capability as demonstrated by the methods specified in NPCC Directories and accepted by the Transmission Operator.	D9 D10
Voltage Reduction		A means to reduce the **demand** by lowering the customer's voltage.	D1 D2 (Appendix B) D5 (Appendix 3)
Voltage Regulating Transformer		A transformer that increases or decreases the voltage magnitude relationship of one circuit with respect to another, most often used to control voltage but also to control **reactive power** flow.	D1
With Due Regard To Reclosing		This phrase means that before any manual system adjustments, recognition will be given to the type of **reclosing** (i.e., manual or automatic) and the kind of **protection.**	D1

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Term	Acronym	Definition	Documents that use this term
Automatic Operating Systems		**Special protection systems**, remedial action schemes, or other operating systems installed on the electric systems that require *no intervention* on the part of **system operators**.	
Auto-reclosing		The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker. Auto-reclosing does not include automatic closing of capacitor or reactor circuit breakers.	
Available Transfer Capability	**ATC**	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability (TTC), less the **Transmission Reliability Margin (TRM)**, less the sum of existing transmission commitments (which includes retail customer service) and the **Capacity Benefit Margin (CBM)**.	
Availability		A measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.	
Average Demand		The electric energy delivered over any interval of time as determined by dividing the total energy by the units of time in the interval.	
Base load Capacity		Capacity used to serve an essentially constant level of customer **demand**. Base load generating units typically operate whenever they are available.	
Billing Demand		The demand upon which customer billing is based as specified in a rate schedule or contract. It may be based on the contract year, a contract minimum, or a previous maximum and, therefore, does not necessarily coincide with the actual measured demand of the billing period.	
Bottled Energy/Power/Capacity		Energy/Power/Capacity which is available at the source but which cannot be delivered to the point of use because of restrictions in the transmission	

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Term	Acronym	Definition	Documents that use this term
		system. Also referred to as Locked-In Energy/Power/Capacity.	
Capacity Benefit Margin	**CBM**	CBM is defined as that amount of transmission transfer capability reserved by **load** serving entities to ensure access to **generation** from interconnected systems to meet **generation reliability** requirements.	
Coincident Demand		The sum of two or more demands that occur in the same demand interval.	
Contingency Reserve Adjustment Factor		A factor used in determining the additional **ten-minute reserve** that each **Area**, not meeting the DCS requirement for a given quarter, must carry. It is calculated using the following formula: $CRA_{quarter} = 2 -$ {the average percentage DCS (expressed as a decimal) for the quarter of measurement}	
Continuous Rating		The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or **element** can support or withstand indefinitely without loss of equipment life. (Normally not used in NPCC)	
Contract Demand		The amount of **capacity** that a supplier agrees to make available for delivery to a particular entity and which the entity agrees to purchase.	
Control Area		An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling **generation** to maintain its net **interchange schedule** with other Control Areas and contributing to frequency regulation of the **Interconnection.**	
Demand Interval		The time period during which electric energy is measured, usually in 15-, 30-, or 60-minute increments.	

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Term	Acronym	Definition	Documents that use this term
Double Element Contingency		A **contingency** involving the loss of two **elements**.	
Emergency Rating		The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units, that a system, facility, or **element** can support or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.	
Firm Demand		That portion of the Contract Demand that a **power** supplier is obligated to provide except when system **reliability** is threatened or during **emergency** conditions.	
First Contingency Incremental Transfer Capability	**FCITC**	The amount of **power**, incremental above normal base **power** transfers, that can be transferred over the transmission network in a reliable manner based on the following conditions: 1. For the existing or planned system configuration, and with normal (pre-**contingency) operating procedures** in effect, all facility loadings are within normal **ratings** and all voltages are within normal limits. 2. The electric systems are capable of absorbing the dynamic **power swings**, and remaining stable, following a **disturbance** that results in the loss of any single electric **element**, such as a transmission line, transformer, or generating unit. 3. After the dynamic **power swings** subside following a **disturbance** that results in the loss of any single electric system **element** as described in 2 above, and after the operation of automatic operating systems, but before any post-**contingency** operator-initiated system adjustments are implemented, all transmission facility loadings are within **emergency**	

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Term	Acronym	Definition	Documents that use this term
		ratings and all voltages are within **emergency** limits.	
First Contingency Total Transfer Capability	**FCTTC**	The algebraic sums of the FCITC values and the appropriate total interregional transfers assumed in the base load flow model used for the FCITC calculations.	
Forced Outage Rate		The hours a generating unit, transmission line, or other facility is forced out of service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.	
Harmonic Current		A periodic component of current having a frequency that is an integral multiple of that currents fundamental frequency. Harmonic currents are normally measured in amperes or in percent of the fundamental frequency current, generally at specific frequencies, such as second and third harmonics. Harmonic currents can, for example, be generated by HVdc converters, **Static Var Compensators** (SVC) and geomagnetically induced currents (GIC).	
High Speed Fault Clearing		Fault clearing consistent with correct operation of high-speed relays and the associated circuit breakers without intentional time delay. *Notes:* The specified time for high-speed relays in present practice is 50 milliseconds (three cycles on a 60Hz basis) or less. [IEEE C37.100-1981]. For planning purposes, a total clearing time of six cycles or less is considered high speed.	
High-Speed Auto reclosing		The auto reclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of auto reclosing is generally not supervised by voltage magnitude or phase angle.	
Integrated Demand		The average of the instantaneous demands over the demand interval.	

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Term	Acronym	Definition	Documents that use this term
Interchange Scheduling		The actions taken by scheduling entities to arrange transfer of electric **power**. The schedule consists of an agreement on the amount, start and end times, ramp rate, and degree of firmness.	
Instantaneous Demand		The rate of energy delivered at a given instant.	
Limiting Contingency		The **contingency** which establishes the **transfer capability**.	
Load Cycle		The normal pattern of **demand** over a specified time period associated with a device or circuit.	
Long Time Emergency (LTE) Rating		The maximum rating of electrical equipment based on nominal ambient conditions and recognizing the nominal **load cycle** for a long period such as 24 hours.	
Manual Reclosing		The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised.	
Negative Shared Activation Reserve Energy		Energy received by an assisting **Area** from a contingent **Area** for an eligible **resource** loss having a concurrent effective loss of demand that exceeds the loss of energy from the **resource** loss, and is implemented at a zero time ramp rate immediately following allocation notification, maintained until the Contingent **Area** requests a return to normal but not longer than thirty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules.**	
Non coincident Demand		The sum of two or more demands that occur in different demand intervals.	
Non recallable Available Transfer Capability	**NATC**	Total Transmission Capability less the **Transmission Reliability Margin**, less non recallable reserved transmission service (including the **Capacity Benefit Margin**).	
Non-Synchronized Reserve		That portion of **operating capacity**, which is available for synchronizing to	

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Term	Acronym	Definition	Documents that use this term
		the network and that capacity which can be made available by applying load management techniques such as curtailing **interruptible loads** or implementing **voltage reductions**.	
Normal Incremental Transfer Capability	**NITC**	The amount of electric **power**, incremental above normal base power transfers, that can be transferred between two areas of the interconnected transmission systems under conditions where pre-**contingency** loadings reach the normal thermal **rating** of a facility prior to any first **contingency** transfer limits being reached. When this occurs, NITC replaces FCITC as the most limiting transfer capability.	
Normal Rating		The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or **element** can support or withstand through the daily **demand** cycles without loss of equipment life.	
NPCC Emergency Criteria Contingencies		The set of contingencies to be observed when operating the **bulk power system** under **emergency** conditions.	
NPCC Normal Criteria Contingencies		The set of contingencies to be observed when operating the **bulk power system** under normal conditions.	
Peak Demand		The highest electric **power** requirement occurring in a given period (e.g., an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system.	
Peaking Capacity		Capacity used to serve **peak demand**. Peaking generating units operate a limited number of hours per year, and their capacity factor is normally less than 20%.	
Permanent Fault		A fault which prevents the affected **element** from being returned to service until physical actions are taken to effect repairs or to remove the cause of the fault.	

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Term	Acronym	Definition	Documents that use this term
Pole (of an ac switching device)		That portion of the device associated exclusively with one electrically separated conducting path of the main circuit of the device.	
Post contingency Operating Procedures		Operating procedures that may be invoked by the **system operator** to mitigate or alleviate system problems after a **contingency** has occurred.	
Power		Apparent Power — The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilo volt amperes (kVA) or megavoltamperes (MVA).	
Power Pool		Two or more interconnected electric systems operated and/or planned to supply **power** for their combined **demand** requirements.	
Recallable Available Transmission Capability	**RATC**	Total Transmission Capability less the **Transmission Reliability Margin**, less recallable transmission service, less non-recallable transmission service (including the **Capacity Benefit Margin**).	
Reclosing *This term by itself is not defined in the NPCC glossary.*		*Need to develop this definition.*	
Regional Reserve Sharing		Procedure that allows participating **Areas** to reduce the requirement for **reserve** within its **Area** due to the availability and deliverability of **reserve** from other **Areas.**	
Regional Reserve Sharing Energy		Energy delivered to a contingent **Area** from assisting **Areas** that is converted from delivered **Shared Activation Reserve Energy** after the **Shared Activation Reserve Energy** has been delivered for 30 minutes; maintained until the Contingent **Area** requests a return to normal but not longer than sixty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules.**	
Shared Activation Reserve Energy		Energy delivered from an assisting **Area** to a contingent **Area** that is implemented at a zero time ramp rate immediately following allocation	

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Term	Acronym	Definition	Documents that use this term
		notification, maintained until the Contingent **Area** requests a return to normal but not longer than thirty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules.**	
Single Element Contingency		A **contingency** involving the loss of one **element**.	
Small-Signal Stability		The ability of the electric system to withstand small changes or **disturbances** without the loss of synchronism among the synchronous machines in the system.	
Stability Limit		See NERC definition.	
Supervision		A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., **synchronism-check**).	
Supervisory Control		A form of remote control comprising an arrangement for the selective control of remotely located facilities by an electrical means over one or more communications media.	
Surge		See NERC definition.	
Synchronism-check		Refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.	
Synchronism-check Relay		A verification **relay** whose function is to operate when two input voltages satisfy predetermined operating parameters.	
Transient Fault		A fault which occurs for a short or limited time, or which disappears when the faulted **element** is separated from all electrical sources and which does not require repairs to be made before the **element** can be returned to service either manually or automatically.	

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Term	Acronym	Definition	Documents that use this term
Transmission Reliability Margin	**TRM**	TRM is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.	
Wheeling		The contracted use of electrical facilities of one or more entities to transmit electricity for another entity.	

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Term	Regional Standard	Acronym	BOT Approved Date	FERC Approved Date	Definition
Current Zero Time (Archive)	PRC-002-NPCC-01	DM	11/04/2010	10/20/2011	The time of the final current zero on the last phase to interrupt. (Source: NERC Glossary of Terms)
Generating Plant (Archive)	PRC-002-NPCC-01	DM	11/04/2010	10/20/2011	One or more generators at a single physical location whereby any single contingency can affect all the generators at that location. (Source: NERC Glossary of Terms)

PSEG
Power LLC

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September 18, 2012

Mr. Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018

Mr. Zito:

I am writing you to inform you of my wishes to nominate a member to the NPCC Regional Standards Committee on behalf of PSEG Power Connecticut LLC, PSEG Power New York LLC, and PSEG New Haven LLC, representing the Generator Owner and Generator Operator sectors.

My colleague's contact information is below:

Christy Koncz
NERC Compliance Specialist
80 Park Plaza, T2B, Newark, NJ 07101
973.430.7576
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I thank you in advance for your consideration of this request. Should you have any questions, please let me know.

Sincerely,

Steven Huber
Manager, NERC Compliance

NPCC, Inc.

1040 Avenue of the Americas - 10th Floor
New York, New York 10018-3703

NPCC Regional Standards Committee
Draft Minutes
Meeting # 12-5

Sept. 5, 2012 10:00 a.m. - 5:00 p.m.
Sept. 6, 2012 8:00 a.m. - 3:00 p.m.

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Dress Business Casual

RSC@npcc.org

Call in 719-785-1707, Guest Code 8287#

Note: For reference. Glossary of Terms Used in NERC Reliability Standards dated May 25, 2012, and the NPCC Glossary of Terms dated Oct. 26, 2011 included in the Meeting Materials.

Items in red from the Sept. 5, 2012 session.
Items in green from the Sept. 6, 2012 session.

Guy Zito called the meeting to order at 09:57 a.m.
Greg Campoli called the meeting to order at 08:40 a.m.

Attendees introduced themselves.

	Name	***Organization***	***Sector***
1.	Guy Zito (Sept. 5, 2012)	Northeast Power Coordinating Council	
2.	Lee Pedowicz	Northeast Power Coordinating Council	
3.	Si-Truc Phan	Hydro-Quebec TransEnergie	2
4.	Don Weaver	New Brunswick System Operator	2
5.	David Kiguel	Hydro One Networks Inc.	1
6.	Greg Campoli	New York Independent System Operator	2
7.	Gerry Dunbar	Northeast Power Coordinating Council	
8.	Brian Shanahan (guest)	National Grid	
9.	Brian Robinson	Utility Services	5
10.	Ron Falsetti (guest)	AESI	
11.	Michael Jones	National Grid	3
12.	Kathleen Goodman	ISO - New England	2
13.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	1
14.	Howard Gugel (guest)	NERC	
15.	Mike Garton	Dominion Resources Services, Inc.	4
16.	Kal Ayoub (guest)	FERC	
17.	Joe Oates (guest) (Sept. 5, 2012)	Hydro-Quebec TransEnergie	
18.	Chantal Mazza (guest)	Hydro-Quebec TransEnergie	
19.	Sarah Martin (guest)	ISO - New England	

On the Phone

	Name	***Organization***	***Sector***
1.	Michael Lombardi	Northeast Utilities	1
2.	Bruce Metruck	New York Power Authority	5
3.	Ben Wu	Orange and Rockland Utilities	1
4.	Sylvain Clermont (Sept. 6, 2012)	Hydro-Quebec TransEnergie	1

Proxy

	Name		***Organization***	***Sector***
	From	**To**		
1.	Peter Yost to Chris de Graffenried		Consolidated Edison Co. of New York, Inc.	3
2.	Wayne Sipperly to Bruce Metruck		New York Power Authority	4

	Name		***Organization***	***Sector***
	From	**To**		
3.	Randy MacDonald to Don Weaver		New Brunswick Power Transmission	1

1. **Introductions. Antitrust Guidelines, Agenda, Roster**
   a. Attendee introductions.
   b. RSC Roster changes.
   c. Read Antitrust Guidelines.
   d. Review of Agenda--inclusions, deletions.

Item 1b--There were no roster changes to report.
Item 1c--Lee Pedowicz read the Antitrust Guidelines.
Item 1d--David Kiguel discussed the new format for the Agenda. Guy Zito replied that there will only be actionable items on it. The Supplement Agenda will only be used for informational and record items.

2. **Review of Previous RSC Meeting Minutes** (in Meeting Materials Package)
   a. Approval of Minutes of previous RSC Meeting.

Item 2a--Guy Zito covered the minutes from the July 18-19, 2012 RSC Meeting. There were no comments. Mike Garton made a motion to accept the Minutes as read. Kathleen Goodman seconded the motion. All participants were in favor.

3. **Action and Ongoing Items List** (in Meeting Materials Package)

Description	Owner	Due	Status
Coordination with the Compliance Committee to develop Joint Activity Action List	Greg Campoli	RSC Meeting	Outgrowth of RSC/CC joint session April 21, 2010.
New York Adoption of More Stringent/Specific NPCC Criteria	Diane Barney	RSC Meeting	Ongoing

   a. NPCC Members on NERC Drafting Teams.
   b. Review Executive Tracking Summary.

Greg Campoli Action Item is ongoing. Diane Barney's revisiting and refilling of more stringent criteria in Directory documents ongoing.

Item 3a--Mike Jones lead the discussion, and has submitted a revision with updated information. Guy Zito asked the question if there could be more direct involvement by

the RSC. Guy Zito asked that the participants let him know if they knew where additional NPCC representation can be used. Si-Truc Phan will talk to Hydro-Quebec TransEnergie's Simon Chano (currently on TFSP) about applying for a position on Project 2007-17's Drafting Team. NERC is looking for a Canadian representative. Simon Chano will have to fill out a self-nomination form, and get management approval. David Kiguel commented that this will have to get done this week in time for the Standard's Committee Sept. 13, 2012 Meeting.

Item 3b--Michael Lombardi discussed. Guy Zito asked how often with the Executive Tracking Summary be updated? Michael Lombardi agreed to update it every two weeks. It will be posted on the NPCC Website. In general, Michael Lombardi will try to issue by the first and fifteenth of every month.

4. Items Requiring RSC Approval

a.

Item 4a--Nothing to report.

5. FERC

a. Issuances below.

Item	NOPR, Petition, Final Rule, Other	Docket No.	Title	Posted
5.1	**Comments**	RM12-1-000	Comments of the North American Electric Reliability Corporation In Response To Notice Of Proposed Rulemaking	7/20/12
	Summary, Instructions, Dates =>	NERC provides these comments in response to FERC's April 19, 2012 NOPR regarding a proposed remand of TPL-001-2 — Transmission System Planning Performance Requirements. In the NOPR, FERC proposed to remand the standard for not meeting the statutory criteria for approval. On April 19, 2012, FERC also issued Order No. 762 remanding NERC's proposed TPL-002-2b. The TPL-002-2b standard includes a provision (footnote b) that allows for planned load shed in a single contingency provided that the plan is documented and alternatives are considered and vetted in an open and transparent stakeholder process. FERC remanded the proposed footnote as vague, unenforceable, and not responsive FERC directives.		

5.2	**Informational Filing**	RM10-5-000	Informational Filing in Compliance with Order No. 758--Interpretation of Protection System Reliability Standard, Docket No. RM10-5-000	7/30/12
	Summary, Instructions, Dates =>	This informational filing is submitted in compliance with Order No. 758 (in Order No. 758, FERC also accepted NERC's commitments to address the concerns in the Protection System Maintenance and Testing standard within the Reliability Standards development process, and directed NERC to file, by July 30, 2012, either a completed project, or an informational filing providing "a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts."). On May 10, 2012, the NERC Standards Committee approved a Standard Authorization Request to revise Reliability Standard PRC-005 to address the maintenance and testing of reclosing relays in NERC Project 2007-17.		
5.3	**Motion for an Extension of Time**	RM06-16-010, RM06-16-011	Quarterly Report of the North American Electric Reliability Corporation On Status of Development of BAL-003	7/31/12
	Summary, Instructions, Dates =>	On March 30, 2012, NERC filed with FERC a motion for an extension of time to submit a revised Resource and Demand Balancing ("BAL") Reliability Standard on Frequency Response and Frequency Bias, BAL-003 ("Motion for an Extension of Time"). On May 4, 2012, FERC issued an order establishing a compliance schedule for NERC to submit a revised BAL-003 consistent with FERC's directives in Order No. 693. FERC established a deadline of May 31, 2013, and directed the submission of informational reports on a quarterly basis describing "the progress NERC is making toward completing its analysis and research as well as the progress it is making in completing work on the other issues and filing a revised BAL-003-0 Reliability Standard by May 31, 2013." The instant filing is submitted in compliance with this directive.		

5.4	**Analysis of NERC Standard Process Results Second Quarter 2012**	RR06-1-000, RR09-7-000	**Analysis of NERC Standard Process Results Second Quarter 2012**	7/31/12
	Summary, Instructions, Dates =>	NERC hereby submits its Analysis of NERC Standards Process Results for the Second Quarter 2012 ("Ballot Results Analysis"). This filing is submitted in response to the FERC January 18, 2007 Order requiring NERC to closely monitor and report the voting results for NERC Reliability Standards each quarter for three years and FERC's subsequent order issued on September 16, 2010, whereby FERC renewed and expanded on its directive for an additional three years.		
5.5	**Notice of Filing**	RM06-16-000	**North American Electric Reliability Corporation; Notice of Filing**	8/1/12
	Summary, Instructions, Dates =>	On March 16, 2012, NERC submitted a filing proposing to amend the NERC Glossary Definition by modifying reference to the defined term "Cascading Outages" to "Cascading outages" within the definition of IROL, approved in FERC's Final Rule issued December 27, 2007 on NERC's Proposed Facilities Design, Connections and Maintenance Reliability Standards.		
5.6	**Petition**	RD12- -000	**PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF AN INTERPRETATION TO RELIABILITY STANDARD CIP-002-4 – CRITICAL CYBER ASSET IDENTIFICATION**	8/1/12
	Summary, Instructions, Dates =>	NERC hereby requests FERC approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA") and Section 39.5 of FERC's Regulations, an interpretation of Reliability Standard CIP-002-4-- Critical Cyber Asset Identification, Requirement R3, to become effective concurrent with the date of a FERC Order approving this petition. Upon FERC approval of the interpretation, the standard will be referred to as CIP-002-4a — Critical Cyber Asset Identification.		

5.7	**Petition**	RD12- -000	**PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF AN INTERPRETATION TO RELIABILITY STANDARD CIP-004-4 – PERSONNEL AND TRAINING**	8/1/12
	Summary, Instructions, Dates =>	NERC hereby requests FERC approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA") and Section 39.5 of FERC's Regulations, an interpretation of Reliability Standard CIP-004-4a--Personnel and Training, Requirements R2, R3, and R4, to become effective concurrent with the date of a FERC Order approving this petition. Upon FERC approval of the interpretation, the standard will be referred to as CIP-004-4a--Personnel and Training.		
5.8	**Order on Reconsideration**	RM11-18-001	**Order On Reconsideration**	8/3/12
	Summary, Instructions, Dates =>	On April 19, 2012, FERC issued a Final Rule remanding a proposal by NERC to modify a provision in TPL-002-0b that allows for planned load shed after a single contingency provided that the plan is documented and alternatives are considered in an open and transparent stakeholder process. The Final Rule found that the proposed provision was vague, unenforceable and not responsive to the previous FERC directives on this matter. Further, in the Final Rule, FERC directed NERC to utilize its Expedited Standards Development Process to develop timely modifications in response to the remand. NERC requests reconsideration, or alternatively rehearing, of the Final Rule with respect to the requirement that NERC use the Expedited Standards Development Process to develop responsive modifications to footnote 'b' of the Reliability Standard. As discussed below, FERC grants NERC's request for reconsideration.		

5.9	**Petition**	RM12-12-000	**Petition of the North American Electric Reliability Corporation For Approval of Proposed NPCC Regional Reliability Standard PRC-006-NPCC-1 – Automatic Underfrequency Load Shedding**	8/3/12
	Summary, Instructions, Dates =>	On May 4, 2012, NERC filed a Petition for Approval of Proposed Regional Reliability Standard PRC-006-NPCC-1--Automatic Underfrequency Load Shedding. It has come to NERC's attention that the implementation plan for the standard was indicated to be in Exhibit A, but is located in Exhibit B at pg. 195 of the pdf filing. This is in error, and NERC submits this filing to correct the record and provide the implementation plan for ease of reference. NERC includes the corrected **Exhibit A** to this filing which contains Regional Reliability Standard PRC-006-NPCC-1 and the accompanying Implementation Plan for Regional Reliability Standard PRC-006-NPCC-1.		
5.10	**Order**	RM11-11-001	**Order Denying Clarification and Rehearing**	8/3/12
	Summary, Instructions, Dates =>	The National Rural Electric Cooperative Association (NRECA) and the American Public Power Association (APPA) filed a joint request for clarification or, in the alternative, rehearing of Order No. 761, in which FERC approved the "Version 4" Critical Infrastructure Protection (CIP) Reliability Standards, submitted by NERC. NRECA and APPA contend that FERC erred in certifying that, pursuant to the Regulatory Flexibility Act of 1980 (RFA), implementation of the Version 4 CIP Reliability Standards would not have a significant impact on a substantial number of small entities. For the reasons discussed in the body of this order, FERC denies the request for clarification and rehearing.		

5.11	**Compliance Filing**	RM11-20-000	**Compliance Filing Of The North American Electric Reliability Corporation In Response To Order No. 763 On Automatic Underfrequency Load Shedding And Load Shedding Plans Reliability Standards**	8/9/12
	Summary, Instructions, Dates =>	On March 31, 2011, NERC filed a petition pursuant to section 215(d)(1) of the Federal Power Act and section 39.5 of FERC's regulations requesting approval of PRC-006-1 (Automatic Underfrequency Load Shedding) and EOP-003-2 (Load Shedding Plans). On October 20, 2011, FERC issued a NOPR. On May 7, 2012, the Commission issued Order No. 763 approving PRC-006-1 and EOP-003-2, and directing NERC to file revisions to one VSL PRC-006-1, Requirement R8, and one VRF for PRC-006-1, Requirement R5. The order also directed NERC to make revisions to future versions of Requirement R9 of PRC-006 and to submit a compliance filing within 30 days of the effective date of the Final Rule explaining how NERC plans to comply. This filing is submitted in compliance with Order No. 763.		
5.12	**Petition**	RD12-5-000	**Petition of the North American Electric Reliability Corporation for Approval of an Interpretation to Reliability Standard CIP-002-4 – Critical Cyber Asset Identification**	8/20/12
	Summary, Instructions, Dates =>	NERC's petition states that the proposed interpretation applies to all versions of the CIP-002 standard, and makes reference to the phrase "Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange," which is included in Requirement R3 of CIP-002-1, CIP-002-2, and CIP-002-3. However, this phrase was modified in CIP-002-4, and the requirement no longer includes examples.		

		Therefore, with respect to the above phrase, the interpretation of CIP-002 should only apply to CIP-002-1, CIP-002-2, and CIP-002-3, and does not apply to CIP-002-4. NERC submits this filing to correct the record.		
5.13	**Petition**	RD12-	**Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard Mod-028-2 – Area Interchange Methodology**	8/24/12
	Summary, Instructions, Dates =>	NERC hereby requests FERC to approve, proposed standard MOD-028-2 as approved by the NERC Board of Trustees on February 9, 2012. The proposed Reliability Standard provides clarification to the currently effective MOD-028-1 standard on the timing and frequency of Total Transfer Capability ("TTC") calculations needed for Available Transfer Capability ("ATC") calculations. NERC is requesting approval of the following: 1. approval of the proposed Reliability Standard effective on the first day of the first calendar quarter after applicable regulatory approval or where no regulatory approval is required, on the first day of the first calendar quarter after Board approval 2. approval of the implementation plan for the proposed Reliability Standard 3. approval of the retirement of Reliability Standard, effective midnight immediately prior to the first day of the first calendar quarter after applicable regulatory approval or where no regulatory approval is required, on the first day of the first calendar quarter after Board approval.		
5.14	**Order Granting Clarification**	RM11-20-001	**Order Granting Clarification**	8/30/12
	Summary, Instructions, Dates =>	The Wisconsin Electric Power Company (Wisconsin Electric) filed a request for clarification or, in the alternative, a request for rehearing of Order No. 763. The request is limited to the discussion of coordination of automatic underfrequency load shedding (UFLS) and manual load shedding programs in Order No. 763. The request for clarification was granted.		

5.15	**Compliance Filing**	RM06-16-000	**Second Quarter 2012 Compliance Filing of The North American Electric Reliability Corporation In Response To Paragraph 629 Of Order No. 693**	8/31/12
	Summary, Instructions, Dates =>	In its March 16, 2007 Order, FERC directed NERC to provide a quarterly informational filing regarding the timeframe to restore power to the auxiliary power systems of U.S. nuclear power plants following a blackout as determined during simulations and drills of system restoration plans. This filing includes information for the second quarter of 2012 and is submitted in compliance with that directive.		
5.16	**Comments**	RM12-6-000, RM12-7-000	**COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING**	9/4/12
	Summary, Instructions, Dates =>	NERC hereby provides these comments in response to FERC's June 22, 2012, NOPR (July 18-19, 2012 RSC Meeting Item 6N-2) regarding revisions to the ERO Definition of BES and RoP. In the NOPR, FERC proposed to approve a modification to the currently-effective definition of "bulk electric system." The proposed modification to the definition removes language allowing for regional discretion in the currently effective bulk electric system definition. The proposed revised definition also establishes a bright-line threshold so that the "bulk electric system" will include facilities operated at 100 kV or higher, if they are Transmission Elements, or connected at 100 kV or higher, if they are Real Power or Reactive Power resources. The new proposed definition contains specific inclusions and exclusions to provide clarity in the definition that the facilities described in certain configurations are included in or excluded from the BES Definition. By this filing, NERC submits its responses to the NOPR.		

5.17	**Comments**	RM12-6-000, RM12-7-000	**COMMENTS OF FLORIDA RELIABILITY COORDINATING COUNCIL MIDWEST RELIABILITY ORGANIZATION NORTHEAST POWER COORDINATING COUNCIL, INC. RELIABILITYFIRST CORPORATION SOUTHWEST POWER POOL REGIONAL ENTITY SERC RELIABILITY CORPORATION TEXAS RELIABILITY ENTITY, INC., AND WESTERN ELECTRICITY COORDINATING COUNCIL**	9/4/12
	Summary, Instructions, Dates =>	"The Regional Entities appreciate the opportunity to provide comments on the NOPR and encourage Commission approval of the revised BES definition, related additions and conforming changes to the ROP, the Detailed Information Exception Request Form and the implementation plan. The revised BES definition addresses the Commission's directives and technical and policy concerns as set forth in Order No. 743 and Order No. 743-A and is "just, reasonable, not unduly discriminatory or preferential, and in the public interest", as required by the Federal Power Act §215(d)(2). The Regional Entities offer the following general comments."		

Item 5.1--Guy Zito reported that the Drafting Team still has work yet that has to be completed. Comments received at NPCC indicated no consensus.
Item 5.2--Guy Zito discussed.
Item 5.3--Guy Zito discussed.
Item 5.4--Kathleen Goodman asked if the Standards Committee was involved with the results. David Kiguel remarked that the Standards Committee only had it for information. Kathleen Goodman commented that the Standards Committee should get more involved with a standard's development, and information should be made public. Guy Zito asked if the information presented here was all that FERC wanted. David

Kiguel and Guy Zito will express their opinions on what the core issues surrounding the issuance of projects are, and a project's development.
Item 5.5--This was a posting for a change to remove a capital letter.
Item 5.6--Guy Zito discussed. The interpretation was good.
Item 5.7--Guy Zito reported that TFIST was good with it.
Item 5.8--Guy Zito discussed.
Item 5.9--Guy Zito discussed.
Item 5.10--FERC's analysis was being questioned. FERC denied a rehearing.
Item 5.11--Guy Zito discussed.
Item 5.12--This is the same as Item 5.6.
Item 5.13--Guy Zito discussed.
Item 5.14--Guy Zito discussed. Wisconsin Electric Power Co. looking for an explanation of the overlap between manual and automatic load shedding. If UFLS is insufficient, then manual load shedding would be needed.
Item 5.15--Quarterly filing.
Item 5.16--Guy Zito lead the discussion.
Item 5.17--NPCC filing. There was no consideration of Canadian issues in the filing. No one was consulted to see if there were any Canadian issues. Kathleen Goodman remarked that this needs to be discussed at the Board level. David Kiguel reported that both the IESO and Hydro One submitted comments. Guy Zito reported that the Massachusetts Department of Public Utilities filed comments saying that because there was no CEAP, FERC should not accept the BES definition. Cost benefit has to be identified. David Kiguel commented that Canadian filings are done with the Provincial entities when documents are submitted to FERC. David Kiguel reported that that is what is done in Ontario. Don Weaver commented that New Brunswick doesn't do it.

6. Posted NERC Projects (in Meeting Materials Package)

	Project and Supporting Materials	**Current and Pending Ballots**		**Join Ballot Pools**		**Posted for Comment**	
1.	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)	Initial Ballot 8/29/12 - 9/7/12	Non-Binding Poll	7/25/12	8/27/12	7/25/12	9/7/12
2.	Adequate Level of Reliability--Revised Definition and Associated Documents					8/15/12	9/13/12
3.	PRC-006-SPP-01 - SPP Automatic Underfrequency Load Shedding					8/15/12	9/28/12
4.	2013-2015 Reliability Standards Development Plan					8/17/12	9/18/12

5.	Project 2007-02 - Operating Personnel Communications Protocols RSAW--comments to be sent to: RSAWfeedback@nerc.net	Successive Ballot 9/11/12 - 9/20/12	Non-Binding Poll			8/22/12	9/20/12
6.	Regional Reliability Standards - MRO Standards Process Manual					8/28/12	10/11/12
7.	Standard Process Manual Revisions to Implement SPIG Recommendations	10/3/12-10/12/12				8/29/12	10/12/12
8.	Project 2009-01 – Disturbance and Sabotage Reporting	Successive Ballot 9/18/12 - 9/27/12	Non-Binding Poll			8/29/12	9/27/12

The goal of the meeting for Item 6 was to put together draft comments for the projects listed.

Item 6-1--The draft responses to the Comment Form were discussed. The possibility of a RSC Member reviewing VRFs and VSLs was discussed. Guy Zito indicated that is recommending a "Yes" vote.

Item 6-2--Discussion centered around resource adequacy. It was felt that the contingencies specified were extreme in nature.

Item 6-3--Guy Zito discussed. RSC has no comments to submit.

Item 6-4--Guy Zito discussed. Typically RSC does not comment unless a member has an issue with an item. Kathleen Goodman commented that Standards EOP-004 and COM-003 are labeled as high priority when they shouldn't be because they do not address a reliability issue.

Item 6-5--The question was raised by the meeting if this Standard was necessary. Should the topic be a guideline?

Item 6-6--Guy Zito discussed. RSC has no comments to submit.

Item 6-7--Guy Zito discussed the slide presentation. As per Section 16.0, the Standards Committee can deviate from the Standards Process Manual. There are safeguards given to provide for justification of those deviations. David Kiguel reported that the Drafting Team decided to stay away from the issue regarding the justification of "No" votes. All "No" votes will be counted. There should be some changes to the balloting software to allow a pull down list that would have choices reflecting what you might not like about a standard. Canadian holidays not considered for conflicts with ballots or comment submission dates.

Item 6-8--Kathleen Goodman commented that EOP-004-2 doesn't help reliability. It is for documentation. If this wasn't done, there would be no effect on reliability.

Regarding Project 2013-02 Paragraph 81, David Kiguel reported that the Drafting Team is looking at the comment responses Friday (Sept. 7, 2012). The Drafting Team is meeting next Wednesday (Sept. 12) and Thursday (Sept. 13).

7. Current NERC Drafting Team Nominations

a.				

8. NERC Meetings (in Meeting Materials Package)

Item 8--Sylvain Clermont reported that Gerry Cauley was disappointed at the length of time it takes to develop a standard. This was discussed at the MRC, BOT, and SOTC meetings. RISC will look at the process, and be careful in not identifying too many items for standards development. In general, all parties are looking to improve the process. Regarding the NERC budget, it is not growing. There is going to be no increase in fees. The question was raised if NERC is doing things beyond its scope. The NERC BOT was receptive to this. NERC activities should be adjusted.

a. Project 2010-17 Definition Of BES (Phase 2)--SDT July 31-August 1, 2012 Meeting.
b. NERC Standards Oversight and Technology Committee August 15, 2012.
c. NERC Board of Trustees approvals--from the August 16, 2012 Meeting, notes.
d. NERC Member Representatives Committee Meeting--August 15, 2012.
e. NERC RSG Sept. 10, 2012 Meeting.
    1. RSG activities to end Oct. 1, 2012.

Item 8a--The MRC wants to shift from a culture of compliance, to a culture of reliability. MRC feels that things are being slowed down because of audit, and compliance fears. The question is how this will be addressed. A group will be formed to review. Kathleen Goodman asked what NERC could curtail. Sylvain Clermont commented that NERC does things to respond to FERC. Should they be doing that? Sylvain Clermont reported that the next MRC Meeting is in November. Greg Campoli asked how fast will this move. Sylvain Clermont doesn't know the timeframe. Greg Campoli commented that the RSC will have to keep track of what's happening. Mike Penstone would welcome any input. Sylvain Clermont will share whatever information he can. Greg Campoli suggested that the RSC have a conference call to go over what's happening. David Kiguel commented that people believe standards development takes too long. It is recognized that standards are complex, and consequently their development takes time. David Kiguel believes the standards process is a success, but can use adjustment. He thinks that there are too many standards. Kathleen Goodman commented that progress could be made if more data was made available to the industry. Sylvain Clermont commented that the root cause has not been identified. Sylvain Clermont also talked about submissions to the BES NOPR. He questioned NPCC's submission of comments. This will be discussed at the next NPCC Board of Directors Meeting. Sylvain Clermont

reported that there was discussion of the BES definition at the MRC Meeting. Pete Heidrich just gave an update.

Greg Campoli asked Chris de Graffenried about Phase 2 of the BES development. Chris de Graffenried reported on the July 31 thru August 1, BESSDT Meeting. Reports were given by groups working on Phase 2 tasks. Voltage thresholds were discussed, such as lowering the voltage from 100kV to 69kV. It was decided to keep 100kV as the threshold. The exception process can always be used. Detailed technical justifications will be needed. A guidance document is being developed. Unfortunately its release date isn't set. It is a work in progress.

9. NERC Compliance Activity (in Meeting Materials Package)

Item 9--Greg Campoli discussed.

a. NERC Compliance Process Bulletin #2012-001--Applicability of PRC-0023-for Generator Owners.

	Draft CANs--Table	**Posted**	**Comments Due**

10. NERC Items of Interest

a. NERC Finance and Audit Committee Meeting--August 15, 2012. NERC 2013 Business Plan and Budget. Page 39 of the redline refers to NPCC and its CEAP.
b. Addressing Zero Defect Concerns in CIP Standards--Industry Webinar Sept. 11, 2012.
c. NERC CEAP.
d. NERC Standards Committee elections. Nominations close Sept. 14, 2012.
e. Notice of Intent to Withdraw Petition for FERC Approval and Retire BAL-004-1.
f. NERC Industry Webinar Version 5 CIP Standards: Successive Ballot Update (2 of 2)--Sept. 21, 2012.
g. 2012 Standards and Compliance Workshops: October 23-25, 2012--Westin Buckhead in Atlanta, Georgia.
h. NERC Realigns Management Team to Better Fit Changing Needs of ERO—August 28, 2012 announcement.
i. NERC Industry Webinar Risk-Based Compliance Monitoring and COM-003-1—Sept. 6, 2012.
j. NERC 2013 Implementation Plan and the Actively Monitored List.
k. Order No. 754 Request for Data or Information effective September 1, 2012.

Item 10--Si-Truc Phan discussed TADS. Will the 100kV bright line have to be implemented next year? Steps will have to be taken to get 100kV facilities included, and this will take time to implement. Is TADS enforceable? A NERC document

published in June, 2012 says that it follows RoP 1600, and is enforceable for the United States entities. Howard Gugel directed the Meeting to the materials posted on the NERC Website. NERC will make a general announcement when the comment period opens. See http://www.nerc.com/page.php?cid=4|62.

Si-Truc described the Hydro-Quebec philosophy of using MOD-029 instead of MOD-028 or MOD-030 for the ATC/TTC calculations. The Standard is being translated into French, and Si-Truc does not want to translate all three Standards if it's not necessary. Kathleen Goodman offered to give Si-Truc the reasons for using each of those three Standards.

Item 10c--David Kiguel remarked that the CEAP Team met last week, and reviewed responses to comments. The document was revised accordingly. The Implementation Plan was worked on. There will be a pilot, and Lessons Learned reviewed. Will be posted again. Approval is needed from the Standards Committee. If necessary, the Standards Committee Executive Committee can approve the posting. Anticipate posting the CEAP in October. Dave Taylor (NERC) says that NERC does not have the staff to do assessments. Because of the confidentiality needed, NERC staff will have to be used. Apparently there is confusion within NERC as to how the CEAP will be handled. Howard Gugel will bring these concerns back to NERC. It has been suggested to use the NPCC to try a pilot.

Item 10d--David Kiguel reported that nominations for the Standards Committee are due September 14, 2012. The openings and composition of the Standards Committee was discussed.

Item 10g--David Kiguel commented that an agenda isn't available. Will be able to attend via Webinar.

Item 10h--Howard Gugel reported on the changes.

Item 10i--Greg Campoli reported.

Howard Gugel reported that NERC is looking to fill two Board of Directors openings. Three Board members are stepping down, only two positions will be filled.

11. NPCC Regional Standards, Directories and Related Items (in Meeting Materials Package)

a. Regional Reliability Reference Directory # 7
Special Protection Systems--revised by TFSP, to be posted in September, 2012.
b. Directory #12 Automatic UFLS alternative IESO Implementation Plan.
c. Update on PRC-006-NPCC-01 Automatic Underfrequency Load Shedding Program.
d. NPCC Fall Standards and Compliance Workshop, Nov. 14-16, 2012 Newport Marriott Hotel.
e. Request for an Interpretation of a Reliability Standard--PRC-002-NPCC-01.
f. Regional Reliability Standards Development Procedure.

g. NPCC Response to a Request for Criteria Interpretation on Regional Reliability Directory# 3 Maintenance Criteria for Bulk Power System Protection.

Item 11--Gerry Dunbar updated the status of the Directories. Task Forces are working on Phase 2. Directories 6, 9, and 10 are completed. Directory #6 was developed under Phase 2. It is anticipated that Directory #5 will be posted for ballot by TFCO during the last quarter of 2012. It is on the agenda for the Sept. 12, 2012 RCC Meeting. TFSS will be approached next week to address the tolerances issue. Tolerances will be included. PRC-006-NPCC-01 has 1% tolerances. Seeking approval to include the tolerances. Directory #12 will be retired when PRC-006-NPCC-01 is approved by all parties. Kathleen Goodman asked that she be notified of all Directory #1 activity. Greg Campoli wants to know who is on the Directory #1 group, and wants to be included in the notifications as well.

Si-Truc Phan questioned whether regional standards are being considered in the Paragraph 81 work. David Kiguel commented that regional standards should be included. Kathleen Goodman reported that two WECC requirements have been included. Si-Truc Phan commented that an eliminated NERC requirement can be adopted in a regional standard.

Greg Campoli commented that Compliance is monitoring Directory developments.

Item 11d--Greg Campoli suggested that a topic to be considered would include NPCC Directories, development, procedures. Kathleen Goodman suggested having classroom sessions to discuss the impact of the BES definition changes.

Item 11e--David Kiguel mentioned that a RSAR had been submitted for PRC-002-NPCC-01, and had been rejected by the RSC. Topic will be on the upcoming RCC Meeting's Agenda. There was a question over the use of BES over BPS in the Standard. Guy Zito commented that a technical justification is needed to accommodate the change in the BES definition. Item 11e--Brian Robinson discussed.

Item 11f--How close do we want to the NPCC Process to mirror NERC? NPCC's process will be needed to revise standards. Item 11f--Lee Pedowicz gave an update.

Item 11g--Gerry Dunbar discussed. Interpretation was done by TFSP.

Greg Campoli lead of a discussion that revolved around how a sub-100kV line in an IROL would be treated with regard to being designated as BES. Does a facility need to go through the inclusion process? Discussed revolved around CIP Standards.

12. <u>Other Items of Interest</u>

a. From the Federal Register, Proposed Rules for the Department of Energy, Reducing Regulatory Burden. Comments due Sept. 7, 2012.

13. Future NPCC Meetings

Ron Falsetti inquired about the RSC 2013 Meeting schedule. Greg Campoli reported that he had discussed with Guy Zito, and that in 2013 there will be two meetings with the Compliance Committee. Before putting together the 2013 RSC Meeting schedule, Guy Zito is waiting for the RCC, and NPCC Board of Director meetings dates.

RSC 2012 Meeting Dates

November 29-30, 2012--Montreal (NPCC General Meeting)

2012 RSC Conference Call Schedule

(call 719-785-1707, Guest Code 8287#)

September 14, 2012	November 16, 2012
September 28, 2012	December 14, 2012
October 12, 2012	December 28, 2012
November 2, 2012	

BOD 2012 Meeting Dates

September 19, 2012--NPCC Offices
October 30, 2012 (Teleconference)
November 28, 2012--Montreal, Quebec

RCC, CC, and Task Force Meeting Dates--2012

RCC	Sept. 12, Nov. 27
CC	9/13-14 (NPCC Offices, NYC), 10/17 (Conference Call), 11/29-30 (Montreal, Joint with RSC)
TFSS	
TFCP	Nov. 7
TFCO	October 17, November 29
TFIST	
TFSP	September 18-19, November 13-14

Meeting adjourned at 16:41.
Meeting adjourned at 10:31.

Respectfully Submitted,

Guy V. Zito, Chair RSC
Assistant Vice President-Standards
Northeast Power Coordinating Council Inc.

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

It is NPCC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. The antitrust laws make it important that meeting participants avoid discussion of topics that could result in charges of anti-competitive behavior, including: restraint of trade and conspiracies to monopolize, unfair or deceptive business acts or practices, price discrimination, division of markets, allocation of production, imposition of boycotts, exclusive dealing arrangements, and any other activity that unreasonably restrains competition.

It is the responsibility of every NPCC participant and employee who may in any way affect NPCC's compliance with the antitrust laws to carry out this commitment.

Participants in NPCC activities (including those participating in its committees, task forces and subgroups) should refrain from discussing the following throughout any meeting or during any breaks (including NPCC meetings, conference calls and informal discussions):

- Industry-related topics considered sensitive or market intelligence in nature that are outside of their committee's scope or assignment, or the published agenda for the meeting;
- Their company's prices for products or services, or prices charged by their competitors;
- Costs, discounts, terms of sale, profit margins or anything else that might affect prices;
- The resale prices their customers should charge for products they sell them;
- Allocating markets, customers, territories or products with their competitors;
- Limiting production;
- Whether or not to deal with any company; and
- Any competitively sensitive information concerning their company or a competitor.

Any decisions or actions by NPCC as a result of such meetings will only be taken in the interest of promoting and maintaining the reliability and adequacy of the bulk power system.

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Andrianne S. Payson at 212-335-4765.

NPCC Reps on NERC Standards Drafting Teams						
Project No.	**Project Title**	**DT Type**	**NPCC Representatives**	**Company**	**Telephone**	**E-mail Address**
2006-02	Assess Transmission Future Needs & Develop Transmission Plans	Standard	Dana Walters	New York Independent System Operator	518-356-8582	dwalters@nyiso.com
2006-06	Reliability Coordination	Standard	Earl Barber	National Grid	315-428-5532	earl.barber@us.ngrid.com
2007-02	Operating Personnel Communications Protocols	Standard	Tom Irvine	Hydro One Networks	705-792-3004	tom.irvine@hydroone.com
2007-06	System Protection Coordination	Standard	David Cirka	National Grid	781-907-3240	david.cirka@us.ngrid.com
2007-07	Vegetation Management	Standard	Orville Cocking	Con Edison	917-789-6885	cockingo@coned.com
2007-07	Vegetation Management	Standard	Dave Morrell	New York State Dept of Public Svc	518-486-7322	david_morrell@dps.state.ny.us
2007-09	Generator Verification	Standard	Vladimir Stanisic	Ontario Power Generation, Inc.	905-357-0322	vlad.stanisic@opg.com
2007-12	Frequency Response	Standard	Mike Potishnak	ISO-NE	413-535-4308	mpotishnak@iso-ne.com
2007-17	Protection System Maintenance & Testing	Standard				
N/A	CIP Interpretations	Interpretation	Mark Engels	Dominion	804-775-5263	mark.engels@dom.com
N/A	CIP Interpretations	Interpretation	David Dunn	IESO	905-855-6286	david.dunn@ieso.ca
N/A	CIP Interpretations	Interpretation	Summer Esquerre	NextEra Energy	561-691-2643	summer.esquerre@nexteraenergy.com
2008-06	Cyber Security for Order 706	Standard	John Lim	Con Edison	212-460-2712	limj@coned.com
2008-06	Cyber Security for Order 706	Standard	Robert Antonishen	Ontario Power Generation	905-262-2674	rob.antonishen@opg.com
2008-06	Cyber Security for Order 706	Standard	Rene Bourassa	Hydro Quebec - TransEnergie	819-694-2507	bourassa.rene@hydro.qc.ca
2008-06	Cyber Security for Order 706	Standard	Thomas Stevenson	Constellation Energy	410-787-5260	thomas.w.stevenson@constellation.com
2009-01	Disturbance and Sabotage Reporting	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com
2009-01	Disturbance and Sabotage Reporting	Standard	Michelle Draxton	Constellation Energy Group	410-474-2993	Michelle.l.draxton@constellation.com
2009-22	Interpretation of COM-02-2	Interpretation	Tom Irvine	Hydro One Networks	705-792-3004	tom.irvine@hydroone.com
2010-05-1	Protection Systems: Phase 1 (Misoperations)	Standard	Paul Difilippo	Hydro One Networks	647-328-7068	paul.difilippo@hydroone.com
2010-07	Generator Requirements at the Transmission Interface	SAR	Louis Slade	Dominion	804-819-2871	louis.slade@dom.com
2010-13.2	Phase 2 of Relay Loadability: Generation	Standard	Steven Hataway	Florida Power & Light		
2010-13.2	Phase 2 of Relay Loadability: Generation	Standard	Ziaodong Sun	Ontario Power Generation		
2010-14.1	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard	Michael Potishnak	ISO-New England	413-535-4308	mpotishnak@iso-ne.com
2010-14.1	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard	Guy Quintin	Hydro Quebec - TransEnergie	514-289-2211 X3150	Quintin.Guy@hydro.qc.ca
2010-17	Definition of Bulk Electric System	Standard	Jennifer Dering	NYPA	914-287-3179	Jennifer.Dering@nypa.gov
2010-17	Definition of Bulk Electric System	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com
2010-17	Definition of Bulk Electric System	Standard	Phil Fedora	NPCC	212-840-4909	pfedora@npcc.org
2010-17	Definition of Bulk Electric System	Standard	Ajay Garg	Hydro One Networks	416.345.5420	ajay.garg@HydroOne.com
2010-17	Definition of Bulk Electric System	Standard	Jennifer T. Sterling	Exelon	630-437-2764	jennifer.sterling@exeloncorp.com
2010-17	Definition of Bulk Electric System - Rules of Procedure	Standard	Martin Boisvert	Hydro Quebec - TransEnergie	514-879-4100	boisvert.martin@hydro.qc.ca
2010-17	Definition of Bulk Electric System - Rules of Procedure	Standard	Ajay Garg	Hydro One Networks	416.345.5420	ajay.garg@HydroOne.com
2013-02	Paragraph 81	Standard	Guy Zito	NPCC	212-840-1070	gzito@npcc.org
2013-02	Paragraph 81	Standard	David Kiguel	Hydro One Networks		david.kiguel@hydroone.com
Source = NERC Standard Drafting Team Rosters - August 2012						
Change Control: Changes since July 2012:						
Project 2007-03 Real Time Operations - Removed Phil Lavallee - National Grid						
Project 2009-01 Disturbance and Sabotage Reporting - Removed Drew Phillips - IESO						
Project 2010-13-2 Phase 2 of Relay Loadability: Generation - Added to report.						
Project 2013-02 Paragraph 81 - Added to report.						

Revised: 11/19/2012

Tab Name	Last Revised	Summary of Changes
NERC RS Exec Tracking Summary	11/19/2012	Project 2006-06 — Reliability Coordination - COM-001-2 & COM-002-3 NERC BOT Approved 11/7/12 Project 2007-02 — Operating Personnel Communications Protocols - posted for comment & ballot thru 12/13/12 Project 2007-06 — System Protection Coordination - posted for comment & ballot thru 12/17/12 Project 2007-12 — Frequency Response - Successive Ballot Approved 11/5/12 Project 2008-06 — Cyber Security — Order 706 -- CIP Version 5 Standards - Industry Approved 11/5/12 Project 2009-01 — Disturbance and Sabotage Reporting - EOP-004-2 NERC BOT Approved 11/7/12 Project 2009-19 — Interpretation of BAL-002-0 R4 and R5 - NERC BOT Approved 11/7/12 Project 2010-INT-01 Interpretation of TOP-006-2 R1.2 and R3 - NERC BOT Approved 11/7/12 Project 2012-INT-04 CIP-007-3 - posted for comment thru 12/10/12 Project 2012-INT-05 – Interpretation of CIP-002-3 - posted for comment & ballot thru 12/20/12 Project 2012-INT-06 CIP-003-3 - posted for comment thru 12/10/12
NERC CANs	8/6/2012	CAN-0011, PRC-005 R2: Interval Start Date for New Equipment - Revision Posted 6/15/12 CAN-0012, Completion of Periodic Activity Requirements During Implementation Plan - Revision Posted 6/15/12
NERC RSAWs	11/19/2012	CIP-001-2a RSAW Issued 10/13/12 COM-003-1 RSAW posted for comment thru 12/13/12 EOP-001-2b RSAW Issued 10/13/12 EOP-003-2 RSAW Issued 10/13/12 EOP-005-2 RSAW Issued 10/13/12 EOP-006-2 RSAW Issued 10/13/12 EOP-008-1 RSAW Issued 10/13/12 FAC-008-3 RSAW Issued 10/13/12 FAC-013-2 RSAW Issued 10/13/12 IRO-014-1 RSAW Issued 10/13/12 PRC-023-2 RSAW Issued 11/15/12
NPCC RRS Tracking Summary	9/20/2012	FERC issued a NOPR on PRC-006-NPCC-01, Automatic Underfrequency Load Shedding Program - Comments on the NOPR are due by 11/26/12.
NPCC Doc Tracking Summary	7/16/2012	B-01: Draft Revised NPCC Guide for the Application of Autorelosing to the Bulk Power System - Posted to Open Process A-07 (retired), Revise Critical Component Definition (Glossary of Terms) - retirement date corrected.
NPCC Directory Tracking Summary	10/12/2012	Directory #5, Reserve, approved by NPCC Full Membership on 10/11/12

NERC Reliability Standards Executive Tracking Summary

Revised: 11/19/2012

Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status	
1	Project 2006-02 — Assess Transmission and Future Needs	High	TPL-001-2	Yes 3rd (Thru 3/16/07)	Yes 5th (Formal Thru 5/31/11)	Yes (Recirculation Thru 7/22/11)	Yes (7/22/11)	Yes (8/4/11)	Yes (10/19/11)		***DATA REQUEST PUBLISHED - Comments due 8/30/12*** On April 19, 2012 FERC issued Order 762 remanding TPL-002-2b and FERC proposed to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	Under Development	
2	Project 2007-07 — Vegetation Management	Normal	FAC-003-2	Yes 3rd (Thru 7/17/07)	Yes 5th (Thru 2/28/11)	Yes 6th (Recirculation Thru 10/13/11)	Yes (10/13/11)	Yes (11/3/11)	Yes (12/21/11)			Under Development	
3	Project 2008-14 — Cyber Security Violation Severity Levels	No	CIP family of standards	Yes 2nd (Thru 04/20/09)	Yes 1st (Thru 04/20/09)	Yes (Recirc Thru 7/16/09)	Yes (7/16/09)	Date?	Date?			Pending Regulatory Approval	
4	Project 2009-26 — Interpretation of CIP-004-1 by WECC	No	CIP-004-1, R2, R3 and R4	x	Yes (Thru 3/23/12)	Yes (Recirculation Thru 4/30/12)	Yes (4/30/12)	Yes (5/9/12)	Yes (8/1/12)			Pending Regulatory Approval	
5	Project 2010-07 — Generator Requirements at the Transmission Interface	High	FAC-001-1~~, FAC-003-3, FAC-003-X,~~ PRC-004-2	Yes 1st (Thru 3/15/10)	Yes 3rd (45 Day Formal Thru 11/18/11)	Yes (Recirculation Thru 12/23/11)	Yes (12/23/11)	Yes (2/9/12)	Yes (7/30/12)			Pending Regulatory Approval	
6	Project 2010-07 — Generator Requirements at the Transmission Interface	High	FAC-003-3, ~~FAC-003-X,~~ PRC-005-1.1b	Yes 1st (Thru 3/15/10)	Yes (30 Day Formal Thru 4/9/12)	Yes (Recirculation Thru 5/3/12)	Yes (5/3/12)	Yes (5/9/12)	Yes (7/30/12)			Pending Regulatory Approval	
7	Project 2010-17 — Definition of Bulk Electric System	High	NERC Glossary Of Terms	Yes 1st (Thru 1/21/11)	- Yes 3rd (Definition Thru 10/10/11) - Yes 2nd (ROP & Tech Principles Thru 10/10/11)	Yes (Recirc Thru 11/21/11)	Yes 11/21/11	Yes (1/18/12)	Yes (1/25/12)				
8	Project 2010-INT-05 CIP-002-1 Requirement R3 for Duke Energy	No	CIP-002-4a, R3	x	Yes (Thru 3/23/12)	Yes (Recirculation Thru 4/30/12)	Yes (4/30/12)	Yes (5/9/12)	Yes (8/1/12)			Pending Regulatory Approval	
9	Project 2011-INT-01 Interpretation of MOD-028 for FPL	No	MOD-028-2	Yes 1st (Thru 11/16/11)	Yes 1st (Thru 11/16/11)	Yes (Recirculation Thru 12/22/11)	Yes (12/22/11)	Yes (2/9/12)	Yes (8/24/12)			Under Development	
10	Project 2006-06 — Reliability Coordination	Normal	IRO-002-3, IRO-005-4, IRO-014-2 COM-001-2, COM-002-3, IRO-001-3 and IRO-014-2	Yes 3rd "Supp" (Thru 9/3/10)	Yes (Thru 7/6/12) COM-001-2 COM-002-3 IRO-001-3	Yes (Recirculation Thru 9/17/12) COM-001-2 (Approved 75.01%) Yes (Recirculation Thru 7/6/12) COM-002-3 IRO-001-3	COM-001-2 Yes (9/17/12) COM-002-3 IRO-001-3 Yes (7/6/12) IRO-002-3 IRO-005-4 IRO-014-2 Yes (7/25/11)	COM-001-2, COM-002-3 Yes (11/7/12) IRO-001-3 Yes (8/16/12) IRO-002-3 IRO-005-4 IRO-014-2 Yes (8/4/11)				Pending Regulatory Approval	x
11	Project 2007-03 — Real-time Operations	High	TOP-001-2, TOP-002-3, TOP-003-2 and PER-001-2	Yes 2nd (Thru 9/07/07)	Yes (Thru 4/20/12)	Yes (Successive Thru 4/20/12)	Update 5/6/12	Update 5/9/12				Under Development	
12	Project 2008-10 — Interpretation of CIP-006-1 R1.1 by Progress Energy	No	CIP-006, R1.1	x	Yes (thru 11/21/11)	Yes (Recirculation Thru 12/19/11)	Yes 12/19/11	Yes (2/9/12)				Under Development	
13	Project 2009-01 — Disturbance and Sabotage Reporting	High	EOP-004-2	Yes 1st (Thru 5/21/09)	Yes (Thru 9/27/12)	Yes (Recirculation Thru 11/5/12)	Yes (11/5/12)	Yes (11/7/12)				Pending Regulatory Approval	x
14	Project 2009-19 — Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group	No	BAL-002-0 R4 and R5	x	Yes - Draft #2 (Thru 9/4/12)	Yes (Recirculation Thru 10/8/12)	Yes (10/8/12)	Yes (11/7/12)				Pending Regulatory Approval	x
15	Project 2009-22 — Interpretation of COM-002-2 R2 by the IRC	High - Interp.	COM-002-2	x	2nd (45 day Formal thru 11/17/11)	Yes (Recirculation Thru 12/23/11)	Yes (12/23/11)	Yes (2/9/12)			Project 2009-22 (COM-002-2),which applies to real-time emergency communications, was approved by NERC BOT with an amendment that calls for the prioritization of a revised standard and a best practices memorandum shared with industry.	Under Development	
16	Project 2010-07 — Generator Requirements at the Transmission Interface	High	PRC-004-2	Yes 1st (Thru 3/15/10)	Yes 1st (45 Day Formal Thru 11/18/11)	Yes (Recirculation Thru 12/23/11)	Yes (12/23/11)	Yes (2/9/12)			PRC-004-2.1a NERC BOT Approved	Under Development	
17	Project 2010-07 — Generator Requirements at the Transmission Interface	High	PRC-005-1.1a	x	Yes (45 Day Formal Thru 4/16/12)	Yes (Recirculation Thru 5/3/12)	Yes (5/3/12)	Yes (5/9/12)					
18	Project 2010-09 — Cyber Security Order 706B — Nuclear Plant Implementation Plan	No	Various CIP Standards	Yes 1st (Thru 3/15/10)	Yes 1st (Thru 3/15/10)	Yes (Recirc Thru 7/2/10)	Yes (7/2/10)	Yes (8/5/10)				Pending Regulatory Filing	
19	Project 2010-INT-01 Interpretation of TOP-006-2 R1.2 and R3 for FMPP	No	TOP-006-3, R1.2 and R3	NA	Yes - Draft #1 (Thru 7/30/12)	Yes - (Recirculation Thru 9/21/12) Approved 87.5%	9/21/2012	Yes (11/7/12)				Pending Regulatory Approval	x
20	Project 2011-INT-02 - Interpretation of VAR-002 for Constellation	No	VAR-002-2b, R2	x	Yes (Thru 6/27/12)	Yes (Recirculation Thru 7/27/12)	Yes (7/27/12)	Yes (8/16/12)			"Rapid Revision"	Pending Regulatory Approval	
21	Project 2007-17 — Protection System Maintenance & Testing RE-INITIATED	High	PRC-005-2	Yes 1st (Thru 9/28/11)	Yes (Thru 8/27/12)	Yes (Recirculation Thru 10/24/12)	Yes (10/24/12)				The standard will be presented to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities	Under Development	
22	Project 2008-06 — Cyber Security — Order 706 -- CIP Version 5 Standards	High	CIP-002-5 thru CIP-009-5, CIP-010-1 and CIP-011-1	x	Yes (Thru 11/5/12)	Yes (Recirculation Thru 11/5/12)	Yes (11/5/12)				Next Steps: The standards will be presented to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.	Industry Approved	x
23	Project 2009-20 — Interpretation of BAL-003-0 R2 and R5 by Energy Mark, Inc.	No	BAL-003-0.1b	x	x	Yes (Recirc Thru 2/26/10)	Yes (2/26/10)					Under Development	
24	Project 2007-02 — Operating Personnel Communications Protocols	High	COM-003-1 and COM-002-2	Yes 2nd (Thru 5/2/07)	Yes (Thru 12/1312)	Yes (Successive Thru 12/13/12)					Posted with RSAW- see RSAW Tab	Under Development	x
25	Project 2007-06 — System Protection Coordination	High	PRC-027-1 Update	Yes 1st (Thru 7/10/07)	Yes (Thru 12/17/12)	Yes (Successive Thru 12/17/12)						Under Development	x

NERC Reliability Standards Executive Tracking Summary

Revised: **11/19/2012**

Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status	
26	Project 2007-09 — Generator Verification	High	MOD-024-2, MOD-025-2, MOD-026-1, MOD-027-1, PRC-019-1 and PRC-024-1	Yes 1st (Thru 5/21/07)	MOD-025-2, MOD-026-1, MOD-027-1, PRC-019-1, PRC-024-1 Yes (Thru 10/29/12)	MOD-026-1 & PRC-024-1 (Successive Thru 11/1/12) MOD-025-2, MOD-026-1, MOD-027-1, PRC-019-1, PRC-024-1 Yes (Successive Thru 10/29/12)						Under Development	
27	Project 2007-12 — Frequency Response	High	BAL-003-1	Yes 3rd (Thru 3/09/07)	Yes 30 day Formal (thru 11/5/12)	Yes (Successive Thru 11/5/12) - Passed					Next Steps: The drafting team will consider all comments received during the formal comment period and successive ballot and, if needed, make revisions to the standards. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.	Under Development	x
28	Project 2009-24 — Interpretation of EOP-005-1 R7 by FMPA	No	EOP-005-1, R7	x	x	Yes 1st (Intitial Thru 1/15/10)					Balloting Deferred per Standards Committee	Under Development	
29	Project 2010-05.1 — Protection Systems: Phase 1 (Misoperations)	High	PRC-004-3	Yes 1st (Informal Thru 7/11/11)	Yes (Draft #2 Thru 9/7/12)	Yes (Initial Thru 9/7/12) - Failed					".1" refers to Phase 1 of the Project		
30	Project 2010-11 — TPL Table 1 Order	No	TPL-001-2a, TPL-001-3, TPL-002-1c	Yes 1st (Thru 5/26/10)	Yes - Formal (Thru 11/19/12)	Yes (Initial Thru 11/19/12)					Draft #7 of TPL-001-2a and Draft #6 of TPL-002-1c posted for combined formal comment period and initial ballot On April 19, 2012 FERC issued Order 762 remanding TPL-002-2b and FERC proposed to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	Under Development	
31	Project 2012-08.1 — Phase 1 of Glossary Updates: Statutory Definitions	No	NERC Glossary Of Terms	For Comment (Thru 8/2/12)	Yes (Thru 8/2/12)	Yes (Intitial Thru 8/2/12)							
32	Project 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	No	TPL-003 and TPL-004	NA	Yes - (Thru 12/5/12)	Yes (Initial Thru 12/5/12)							
33	Project 2012-INT-05 – Interpretation of CIP-002-3 for OGE	No	CIP-002	NA	Yes (Thru 12/20/12)	Yes (Initial Thru 12/20/12)						Under Development	x
34	Project 2013-02 — Paragraph 81	No		Draft for Comment (Thru 9/4/12)	Yes (Thru 12/10/12)	Yes (Initial Thru 12/10/12)					The purpose of the project is to retire or modify FERC-approved Reliability Standard requirements that as FERC noted, "provide little protection to the reliable operations of the BES", are redundant or unnecessary, or to retire or modify a FERC-approved Reliability Standard requirement to increase the efficiency of the ERO's compliance programs.	Under Development	
35	Interpretation 2012-INT-04 CIP-007-3 for ITC	No	CIP-007-3	NA	Yes (Thru 12/10/12)								x
36	Interpretation 2012-INT-06 CIP-003-3 for Consumers Energy	No	CIP-003-3	NA	Yes (Thru 12/10/12)								x
37	Project 2007-11 — Disturbance Monitoring	No	PRC-002-1 and PRC-018-1	Yes 1st (Thru 4/20/07)	Yes 1st (Thru 3/18/09)							Under Development	
38	Project 2008-12 — Coordinate Interchange Standards	No	INT-004-, INT-006-4, INT-009-2, INT-010-2 and INT-011-1	Yes 1st (Thru 7/31/08)	Yes 1st (Thru 12/11/09)							Under Development	
39	Project 2009-02 — Real-time Reliability Monitoring and Analysis Capabilities	No	"New"	Yes 2nd (Thru 2/18/10)	Yes 1st (Informal Thru 4/4/11)						Concept White Paper posted for informal comment period	Under Development	
40	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	No	PRC-025-1	x	Yes 30 day formal (thru 11/5/12)						- ".2" refers to Phase 2 of the Project - 2/15/12 - FERC has granted NERC a one-year extension of time to and including September 30, 2013 to complete the Project pursuant to the Commission's Order No. 733. [Docket No. RM08-13-001]		
41	Project 2010-14.1 — Phase 1 of Balancing Authority Reliability-based Control: Reserves	No	BAL-001-1, BAL-002-2, BAL-012-1, BAL-013-1	NA	Yes - Draft #1 Thru 7/3/12						As of July 28, 2010 this project has merges Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control into a single project	Under Development	
42	Project 2010-16 — Definition of System Operator	No	NERC Glossary Of Terms	Yes 1st (Thru 12/3/10)	Yes 1st (Thru 12/3/10)							Under Development	
43	Project 2010-17 — Definition of Bulk Electric System - Phase 2	High	NERC Glossary Of Terms	For Comment (Thru 2/3/12)	Yes - Informal (Guidance Document Thru 11/5/12)							Under Development	
44	Project 2008-01 — Voltage and Reactive planning and control	No	VAR-001 and VAR-002	Yes 2nd (Thru 3/26/10)								Under Development	
45	Project 2008-02 — Undervoltage Load Shedding	No	PRC-010-0 and PRC-022-1	Yes 1st (Thru 02/19/10)							June 2010 SC meeting - Project deferred until Higher Priority projects are completed	Project Deferred	
46	Project 2009-03 — Emergency Operations	No	EOP-001, EOP-002, EOP-003 and IRO-001	Yes 1st (Thru 1/15/10)								Under Development	
47	Project 2009-05 — Resource Adequacy Assessments	No	"New"	Yes 2nd (Thru 3/30/06)								Under Development	
48	Project 2009-07 — Reliability of Protection Systems	No	"New"	Yes 1st (Thru 2/18/09)							Pending prioritization - may be postponed	Under Development	
49	Project 2010-08 — Functional Model Glossary Revisions	No		Yes 1st (Thru 2/22/10)							June 2010 SC meeting - Project deferred until Higher Priority projects are completed	Project Deferred	
50	Project 2013-01 — Cold Weather Preparedness		"TBD"	Draft for Comment (Thru 10/24/12)									

NERC Reliability Standards Executive Tracking Summary

Revised: **11/19/2012**

Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
51	Project 2009-04 — Phasor Measurement Units	No										Project has not started
52	Project 2010-01 — Support Personnel Training	No									2/15/12 - FERC has granted NERC a two-year extension of time to and including September 30, 2014 to complete the Project pursuant to the Commission's Order No. 742. [Docket No. RM09-25-000]	Project has not started
53	Project 2010-02 — Connecting New Facilities to the Grid	No										Project has not started
54	Project 2010-03 — Modeling Data	No										Project has not started
55	Project 2010-04 — Demand Data	No										Project has not started
56	Project 2010-06 — Results-based Reliability Standards	No	Results-based Reliability Standards Transistion Plan								Transistion Plan posted 7/26/10	
57	Project 2010-INT-02 Interpretation of TOP-003-1 R2 for FMPP	No	TOP-003-1, R2								Requester has been contacted to see if a CAN would satisfy their concerns until the standard is revised - awaiting response	On Hold
58	Project 2010-INT-03 Interpretation of TOP-002-2a R2, R8, and R19 for FMPP	No	TOP-002-2a, R2, R8 and R19								Requester has been contacted to see if a CAN would satisfy their concerns until the standard is revised - awaiting response	On Hold
59	Project 2012-01 Equipment Monitoring and Diagnostic Devices	No	FUTURE									
60	Project 2012-02 Physical Protection	No	FUTURE									
61	Pre-2006 — Operate Within Interconnection Reliability Operating Limits	No	IRO-008-1, IRO-009-1 and IRO-010-1a	Yes 2nd (Thru 9/23/02)	Yes 9th (Thru 4/25/08)	Yes 1st (Recirc Thru 8/21/08)	Yes (8/21/08)	Yes (10/17/08)	Yes (12/31/09)	Yes (3/17/11)	- Order on Rehearing published in Federal Register on July 19, 2011 - Rule published in Federal Register on March 23, 2011	Completed
62	Project 2006-01 — System Personnel Training	No	PER-004-2 and PER-005-1	Yes 2nd (Thru 3/20/06)	Yes 4th (Thru 7/17/08)	Yes 5th (Recirc Thru 12/22/08)	Yes (12/22/08)	Yes (04/01/09)	Yes (9/30/09)	Yes (11/18/10)		Completed
63	Project 2006-03 — System Restoration and Blackstart	No	EOP-001-1, EOP-005-2 and EOP-006-2	Yes 2nd (Thru 3/09/07)	Yes 4 th (Thru 11/18/08)	Yes 5th (Recirc Thru 5/18/09)	Yes (5/18/09)	Yes (8/5/09)	Yes (12/31/09)	Yes (3/17/11)	- Order on Rehearing published in Federal Register on July 19, 2011 (Effective Std EOP-001-2) - Rule published in Federal Register on March 23, 2011	Completed
64	Project 2006-04 — Backup Facilities	No	EOP-008-1	Yes 2nd (Thru 3/16/07)	Yes 5th (Thru 3/8/10)	Yes 7th (Recirc Thru 7/26/10)	Yes (7/26/10)	Yes (8/5/010)	Yes (2/11/11)	Yes (4/21/11)	Posted in Federal Register on 4/28/11	Completed
65	Project 2006-08 — Transmission Loading Relief	No	IRO-006-5 and IRO-006-East-1	Yes (For DT Nomination 1/12/07)	Yes 4th (Thru 11/30/09)	Yes 6th (Recirc Thru 8/30/10)	Yes (8/30/10)	Yes (11/4/10)	Yes (1/13/11)	Yes (4/21/11)		Completed
66	Project 2007-01 — Underfrequency Load Shedding	No	EOP-003-1 and PRC-006-1	Yes 3rd (Thru 3/29/07)	Yes 3rd (Thru 7/16/10)	Yes 6th (Recirc Thru 10/28/10)	Yes (10/28/10)	Yes (11/4/10)	Yes (3/31/11)	Yes (5/7/12)		Completed
67	Project 2007-04 — Certifying System Operators	Normal	PER-003-1	Yes 2nd (Thru 1/31/08)	Yes 1st (Thru 11/20/09)	Yes 3rd (Recirc Thru 12/13/10)	Yes (12/31/10)	Yes (2/17/11)	Yes (4/29/11)	Yes (9/15/11)		Completed
68	Project 2007-05 — Balancing Authority Controls	No	NA	NA	NA	NA	NA	NA	NA	NA	As of July 28, 2010 this project has been merged with Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control	NA
69	Project 2007-17 — Protection System Maintenance & Testing	High	PRC-005-2	Yes 1st (Thru 7/10/07)	Yes 4th (30 day formal Thru 5/12/11)	Yes 8th (Recirculation Thru 6/30/11)	Failed to reach ballot pool aproval	NA	NA	NA	After PRC-005-2 failed to reach ballot pool approval in the recirculation ballot that ended on 6/30/11, the drafting team revised the standard. The Standards Committee authorized re-initiating the project with a posting of the SAR and revised standard for a 45-day comment period, with an initial ballot of the standard conducted during the last 10 days of the comment period.	Re-initiated
70	Project 2007-18 — Reliability-based Control	No	NA	NA	NA	NA	NA	NA	NA	NA	As of July 28, 2010 this project has been merged with Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control	NA
71	Project 2007-23 — Violation Severity Levels	No	Six sets of VSLs for various standards	Yes 2nd "Supp" (Thru 9/16/10)	Yes 6th (Thru 2/18/11)	Yes (Non-Binding Poll Thru 2/18/11	NA - Non Binding Poll Only	Yes (3/10/11)	Yes (3/21/11)	Yes (5/19/11)		Completed
72	Project 2007-24 - Interpretation of TPL-002 and TPL-003	No	TPL-002-0a and TPL-003-0a	x	x	Yes 2nd (Thru 7/7/08)	Yes (7/7/08)	Yes (7/30/08)	Yes (10/24/08)	Yes (4/23/10)		Completed
73	Project 2007-27 — Interpretation of CIP-006 R1.1 by SCE&G	No	CIP-006, R1.1	x	x	Yes (Recirc Thru 12/4/07)	Yes (12/4/07)	Yes (2/12/08)	Yes (12/22/09)	Yes (5/19/11)		Completed
74	Project 2008-06 — Cyber Security — Order 706 (CIP-002-4)	High	CIP-002-4 thru CIP-009-4	x	Yes 1st (Thru 11/3/10)	Yes Recirc Thru 12/30/10) - passed	Yes (12/30/10)	Yes (1/24/11)	Yes (2/10/11)	Yes (4/19/12)		Completed
75	Project 2008-06 — Cyber Security — Order 706 (VRFs and VSLs)	No	CIP VRFs and VSLs	x	Yes 1st (Thru 4/20/09)	Yes (Recirc Thru 11/12/09)	Yes (11/12/09)	Yes (12/16/09)	Yes (12/18/09)	Yes (1/20/11)		Completed
76	Project 2008-07 — Interpretation of EOP-002-2 R6.3 and R7.1 by Brookfield Power	No	EOP-002-2, R6.3 and R7.1	x	x	Yes (Recirc Thru 8/31/09)	Yes (8/31/09)	No (Remanded 2/16/10)	NA	NA	2/16/10 NERC BOT: (1) Remands the proposed interpretation of EOP-002-2, Requirements R6.3 and R7.1, to the Standards Committee because the proposed interpretation adds requirements not in the standard, thereby exceeding the permissible scope of an interpretation, and (2) Directs the Standards Committee to initiate action to revise EOP-002-2 as appropriate	NA
77	Project 2008-08 — EOP VSL Revisions	No	EOP family of standards	Yes 1st (Thru 5/19/08)	Yes 2nd (Thru 12/3/09)	Yes (Non-Binding Poll Thru 2/18/11	NA - Non Binding Poll Only	Yes (3/10/11)	Yes (3/21/11)	Yes (5/19/11)		Completed
78	Project 2008-09 — Interpretation of EOP-001-0 R1 by Regional Entity Compliance Managers	No	EOP-001-0, R1	x	x	Yes 4th (Recirc Thru 10/14/10)	Yes (10/14/10)	Yes (11/4/10)	Yes (9/9/11)	Yes (12/15/11)	The standard will now be referred to as EOP-001-2b	Completed
79	Project 2008-11 — Interpretation of VAR-002a by ICF Consulting	No	VAR-002-1.1b	x	x	Yes (Recirc Thru 1/6/09)	Yes (1/6/09)	Yes (2/10/09)	Yes (3/5/09)	Yes (9/16/10)		Completed
80	Project 2008-15 — Interpretation of CIP-006-1a By US Army Corps of Engineers	No	CIP-006-1a, R4	x	x	Yes (Recirc Thru 2/16/09)	Yes (2/16/09)	Yes (8/5/09)	Yes (12/22/09)	Yes (5/19/11)		Completed
81	Project 2008-18 — Interpretation of TOP-005-1 and IRO-005-1 by Manitoba Hydro	No	TOP-005-1 , R3 and IRO-005-1, R12	x	x	Yes (Recirc Thru 4/27/09)	Yes (4/27/09)	Yes (11/5/09)	Yes (11/24/09)	Yes (4/21/11)	Posted in Federal Register on 4/26/11	Completed

NERC Reliability Standards Executive Tracking Summary

Revised: **11/19/2012**

Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
82	Project 2009-06 — Facility Ratings	Normal	FAC-008-3 (was FAC-008-2)	Yes 2nd (Thru 9/9/09)	Yes 3rd (Formal Thru 5/2/11)	Yes 6th (Recirculation Thru 5/23/11)	Yes (5/23/11)	Yes (5/24/11)	Yes (6/15/11)	Yes (11/17/11)	FAC-008-3 is effective the first day of the first calendar quarter that is twelve months after issuance of the FERC Order. FAC-008-3 combines FAC-008-1 and FAC-009-1 into a single standard.	Completed
83	Project 2009-08 — Nuclear Plant Interface Coordination	No	NUC-001-2	Yes 1st (Thru 3/18/09)	Yes 1st (Thru 3/18/09)	Yes (Recirc Thru 7/20/09)	Yes (7/20/09)	Yes (8/5/09)	Date?	Yes (1/21/10)		Completed
84	Project 2009-09 — Interpretation of CIP-001-1 by Covanta	No	CIP-001-1a	x	x	Yes (Recirc Thru 10/9/09)	Yes (10/09/09)	Yes (2/16/10)	Yes (4/21/10)	Yes (2/2/11)	Approved by Letter Order	Completed
85	Project 2009-10 — Interpretation of PRC-005-1 R1 by Compliance Monitoring Processes Working Group (CMPWG)	No	PRC-005-1, R1	x	x	Yes (Recirc Thru 8/6/09)	Yes (8/6/09)	Yes (11/5/09)	Yes (11/17/09)	Yes (2/3/12)	Posted in Federal Register 2/13/12 - Effective 3/14/12	Completed
86	Project 2009-11 — Interpretation of IRO-010-1 R1.2 and R3 by WECC Reliability Coordination Subcommittee	No	IRO-010-1 R1.2 and R3 --> IRO-010-1a	x	x	Yes (Recirc Thru 6/5/09)	Yes (6/5/09)	Yes (8/5/09)	Yes (12/31/09)	Yes (3/17/11)	NOPR issued 11/18/10, Comments were due 1/24/11	Completed
87	Project 2009-12 — Interpretation of CIP-005-1 by PacifiCorp	No	CIP-005-3a	x	x	Yes (Recirc Thru 10/26/09)	Yes (10/26/09)	Yes (2/16/10)	Yes (4/21/10)	Yes (2/2/11)	Approved by Letter Order	Completed
88	Project 2009-13 — interpretation of CIP-006-1 by PacifiCorp	No	CIP-006-2c	x	x	Yes (Recirc Thru 12/23/09)	Yes (12/23/09)	Yes (2/16/10)	Yes (4/20/10)	Yes (7/15/10)		Completed
89	Project 2009-14 — Interpretation of TPL-002-0 R1.3.10 by PacifiCorp	No	TPL-002-0, R1.3.10	x	x	Yes (Recirc Thru 8/6/09)	Yes (8/6/09)	Yes (11/5/09)	Yes (11/17/09)	Yes (9/15/11)	Posted in Federal Register on 9/22/11 - Effective Date: This rule will become effective October 24, 2011	Completed
90	Project 2009-15 — Interpretation of MOD-001-1 R2 and R8 and MOD-029-1 R5 and R6 by NYISO	No	MOD-001-1, R2 and R8 and MOD-029-1 R5 and R6	x	x	Yes (Recirc Thru 7/17/09)	Yes (7/17/09)	Yes (11/5/09)	Yes (12/2/09)	Yes (9/16/10)		Completed
91	Project 2009-16 — Interpretation - CIP-007-1, R2 — Systems Security Management	No	CIP-007-2a	x	x	Yes (Intitial Thru 9/21/09)	Yes (9/21/09)	Yes (11/5/09)	Yes (11/17/09)	Yes (3/18/10)		Completed
92	Project 2009-17 — Interpretation of PRC-004-1 and PRC-005-1 R2 by Y-W Electric and Tri-State G & T	No	PRC-004-1 and PRC-005-1	x	x	Yes 3rd (Recirc Thru 12/3/10)	Yes (12/3/10)	Yes (2/17/11)	Yes (4/15/11)	Yes (9/26/11)		Completed
93	Project 2009-18 — Withdraw Three Midwest ISO Waivers	No	BAL-006-2 and INT-003-3	x	x	Yes (Intitial Thru 9/8/09)	Yes (9/8/09)	Yes (11/5/09)	Yes (11/20/09)	Yes (1/6/11)		Completed
94	Project 2009-21 — Cyber Security Ninety-day Response — CIP Family of Standards	No	CIP-002 through CIP-009, V3	Yes 1st (Thru 11/12/09)	Yes 1st (Thru 11/12/09)	Yes (Recirc Thru 12/14/09)	Yes (12/14/09)	Yes	Yes (1/19/10)	Yes (3/18/10)		Completed
95	Project 2009-23 — Interpretation of CIP-004-2 R3 by Army Corps of Engineers	No	CIP-004-2	x	x	Yes 2nd (Intitial Thru 4/8/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
96	Project 2009-25 — Interpretation of BAL-001-01 and BAL-002-0 by BPA	No	BAL-001-0.1a and BAL-002-0	x	x	Yes 1st (Intitial Thru 1/15/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
97	Project 2009-27 — Interpretation of TOP-002-2a R10 by FMPP	No	TOP-002-2a, R10	x	x	Yes (Recirc Thru 10/16/10)	Yes (10/16/10)	Yes (11/4/10)	Yes (4/15/11)	Yes (10/20/11)		Completed
98	Project 2009-28 — Interpretation of EOP-001-1 and EOP-001-2 R2.2 by FMPP	No	EOP-001-1 and EOP-001-2	x	x	Yes (Recirc Thru 10/15/10)	Yes (10/15/10)	Yes (11/4/10)	Yes (9/9/11)	Yes (12/15/11)	The standard will now be referred to as EOP-001-2b	Completed
99	Project 2009-29 — Interpretation of TOP-002-2a R6 by FMPP	No	TOP-002-2a, R6	x	x	Yes 1st (Intitial Thru 2/22/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
100	Project 2009-30 — Interpretation of PRC-001-1 R1 by WPSC	No	PRC-001-1	x	x	Yes 1st (Intitial Thru 2/26/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
101	Project 2009-31 — Interpretation of TOP-001-1 R8 by FMPP	No	TOP-001-1, R8	x	x	Yes 1st (Intitial Thru 3/16/10)	Yes (3/16/10)	Yes (5/12/10)	Yes (7/16/10)	Yes (9/15/11)	Posted in Federal Register on 9/20/11 - Effective Date: This rule will become effective November 21, 2011	Completed
102	Project 2009-32 — Interpretation of EOP-003-1 R3 and R5 by FMPP	No	EOP-003-1, R3 and R5	x	x	Yes 2nd (Re-ballot Thru 3/31/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
103	Project 2010-10 — FAC Order 729	No	FAC-013-2	Yes 1st (Thru 4/29/10)	Yes 3rd (Thru 1/8/11)	Yes 3rd (Recirc Thru 1/23/11)	Yes (1/23/11)	Yes (1/24/11)	Yes (1/28/11)	Yes (11/17/11)	FAC-013-2 is effective the first day of the calendar quarter twelve months after Commission approval.	Completed
104	Project 2010-12 — Order 693 Directives	No	BAL-002-1, EOP-002-3, FAC-002-1, MOD-021-1, PRC-004-2 and VAR-001-2	Yes 1st (Thru 7/13/10)	Yes 1st (Thru 7/13/10)	Yes 2nd (Recirc Thru 7/31/10)	Yes (7/31/10)	Yes (8/5/10)	Yes (9/9/10)	Yes (1/10/11)		Completed
105	Project 2010-13 — Relay Loadability Order	Normal	PRC-023-2	Yes 1st (Thru 9/19/10)	Yes 3rd (Thru 12/16/10)	Yes 3rd (Recirculation Thru 3/6/11)	Yes (3/6/11)	Yes (3/10/11)	Yes (3/18/11)	Yes (3/15/12)	Posted in Federal Register 3/21/12 - Effective Date 5/7/12	Completed
106	Project 2010-15 — Urgent Action Revisions to CIP-005-3	Urgent	CIP-005-4	Yes 1st (Thru 9/27/10)	Yes 3rd (Thru 4/28/11)	Yes 3rd (Thru 4/28/11)	NA	NA	NA	NA	Absorbed into Project 2008-06; Project 2010-15 curtailed	Project Curtailed
107	Project 2010-INT-04 Interpretation of EOP-001-1 R2.4 for FMPP	No	EOP-001-1, R2.4	x	x	x	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
108	Urgent Action SAR for Revision	No	BAL-004-1	Yes 2nd (Thru 10/18/07)	Yes 2nd (Thru 10/18/07)	Yes 1st (Recirc Thru 12/4/07)	Yes (12/4/07)	Withdrawn 8/16/12 ~~Yes (3/26/08)~~	~~Yes (3/11/09)~~	NA	The Board of Trustees withdrew its approval of BAL-004-1: Time Error Correction on August 16, 2012. BAL-004-1 has been withdrawn and retired. BAL-004-0 will remain enforceable.	Withdrawn

Acronyms:
SAR- Standards Authorization Request
RS- Reliability Standard
DT- Drafting Team
SC - NERC Standards Committee
TBD- To Be Determined
BOT- NERC Board of Trustee

NERC Compliance Application Notice Executive Tracking Summary

Revised: 8/6/2012

Further details regarding the individual documents may be found at: http://www.nerc.com/page.php?cid=3%7C22%7C354

CAN#	Project No. / Title	Associated Standard or Issue	Requirement	Advance Notice?	Posted for Comment?	Comments Posted?	CAN Issued?	Comments
~~CAN-0001~~	~~INT-004-2 R1: Compliance Application Notice~~	~~INT-004-2~~	~~1~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
~~CAN-0002~~	~~TOP-003-0 R1.3: Compliance Application Notice~~	~~TOP-003-0~~	~~1.3~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
~~CAN-0003~~	~~IRO-006-4.1 R2: Compliance Application Notice~~	~~IRO-006-4.1~~	~~2~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
~~CAN-0004~~	~~IRO-004-1 R3: Compliance Application Notice~~	~~IRO-004-1~~	~~3~~	~~x~~	~~x~~	~~x~~	~~Yes (5/5/10)~~	Retired August 31, 2011
CAN-0005	CIP-002-3 R3: Compliance Application Notice (Revised)	CIP-002-3	3	x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (12/9/11)	Yes (12/9/11 - Revised)	Revised CAN posted 12/9/11
CAN-0006	EOP-005 R7: Verification of Restoration Procedure (Revised)	EOP-005-1	7	x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (11/11/11)	Yes (11/11/11)	Revised CAN posted 11/11/11
CAN-0007	CIP-004-2 R4.2 and CIP-004-3 R4.2: Compliance Application Notice	CIP-004-2, CIP-004-3	4.2, 4.2	x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (12/9/11)	Yes (12/9/11 - Revised)	Revised CAN posted 12/9/11
CAN-0008	PRC-005 R2: Basis for First Maintenance and Testing Date (Revised)	PRC-005-1	R2 Pre-June 18 evidence	x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (11/16/11)	Yes (4/10/12 - Revised)	Revised CAN posted 4/10/12
CAN-0009	FAC-008 and FAC-009: Facility Ratings and Design Specifications (Revised)	FAC-008 & FAC-009	R1, R1, R2	x	Yes 9/23/11 (Thru 10/14/11)	Yes (11/11/11)	Yes (11/11/11)	Revised CAN issued 11/11/11
CAN-0010	Implementation of Annual in Reliability Standards Requirements (Revised)	Definition of "Annual"		x	x	Yes (11/16/11)	Yes (11/16/11)	Revised CAN posted 11/16/11
CAN-0011	PRC-005 R2: Interval Start Date for New Equipment (Revised)	PRC-005-1	R2 - new equipment	x	x	Yes (11/16/11)	Yes (6/15/12 - Revised)	Revised CAN posted 6/15/12
CAN-0012	Completion of Periodic Activity Requirements During Implementation Plan (Revised)			x	Yes 1/21/11 (Thru 2/4/11)	Yes (11/16/11)	Yes (6/15/12 - Revised)	Revised CAN posted 6/15/12
CAN-0013	PRC-023 R1 and R2: Effective Dates for Switch-On-To-Fault Schemes (Revised)	PRC-023		x	Yes 1/21/11 (Thru 2/4/11)	Yes (11/16/11)	Yes (11/16/11)	Revised CAN posted 11/16/11
CAN-0015	Unavailability of NERC Software Tools			x	Yes 2/4/11 (Thru 2/18/11)	Yes (12/9/11)	Yes (12/9/11 - Revised)	Revised CAN posted 12/9/11
~~CAN-0016~~	~~CIP-001 R1: Sabotage Reporting Procedure (Revised)~~	~~CIP-001~~		~~x~~	~~Yes 8/15/11 (Thru 9/6/11) - Revision~~	~~Yes (10/14/11)~~	~~Yes (10/14/11)~~	REMANDED 2/8/12 and then WITHDRAWN 2/16/12
CAN-0017	CIP-007 R5: Technical and Procedural System Access and Password Controls	CIP-007	R5	x	Yes 9/23/11 (Thru 10/14/11)	Yes (11/11/11)	Yes (11/11/11)	Revised CAN posted 11/11/11
CAN-0018	FAC-008 R1.2.1: Terminal Equipment (Revised)	FAC-008		x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (11/11/11)	Yes (11/11/11)	Revised CAN posted 11/11/11
CAN-0019	CIP-007 R3.2 Implementation of Software Security Patches or Upgrades	CIP-007	R3.2	x	Yes 4/10/12 (Thru 6/4/12)	Yes (4/26/12)		
CAN-0020	Draft CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002	TPL-002, TPL-003, TPL-004		x	Yes 10/19/11 (Thru 11/9/11)	Yes (12/15/11)	Yes (12/15/11)	
CAN-0021	Draft CAN-0021 COM-002 Definition of Directive and Use of Three-Part Communications	COM-002		Yes (5/9/11)				
CAN-0022	CAN-0022 VAR-002-1.1b R1 and R3	VAR-002		x	Yes 4/19/11 (Thru 5/11/11)	Yes (12/9/11)	Yes (12/9/11 - Revised)	Revised CAN posted 12/9/11
CAN-0023	CIP-005 R3, CIP-006 R6 Logging System Failures	CIP-005	R3	x	Yes 4/10/12 (Thru 6/4/12)	Yes (4/26/12)		
CAN-0024	Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	CIP-002 through CIP-009		x	Yes 5/20/11 (Thru 6/10/11)	Yes (11/30/11)	Yes (12/15/11)	
CAN-0026	CAN-0026 TOP-006-X R3 Protection Relays	TOP-006		x	Yes 4/19/11 (Thru 5/11/11)	Yes (12/9/11)	Yes (12/9/11 - Revised)	Revised CAN posted 12/9/11
CAN-0027	Draft CAN-0027 TOP-003 R1.1 and R2 Generator	TOP-003		x	Yes (Thru 12/14/11)	Yes (12/21/11)	Yes (12/21/11)	
CAN-0028	TOP-006 R1.2: Reporting Responsibilities (Revised)	TOP-006		x	Yes 4/19/11 (Thru 5/11/11)	Yes (11/16/11)	Yes (11/16/11)	Revised CAN posted 11/16/11
CAN-0029	Protection System Misoperations, PRC-004-1 R1, R2, R3	PRC-004	R1, R2, R3	x	Yes 9/23/11 (Thru 10/14/11)	Yes (11/11/11)	Yes (12/9/11)	
CAN-0030	Draft CAN-0030 Attestations	Attestations		x	Yes 10/19/11 (Thru 11/9/11)	Yes (11/22/11)	Yes (12/9/11)	
CAN-0031	Acceptable Opening Dimensions, CIP-005 and CIP-006	CIP-005 and CIP-006		x	Yes 9/23/11 (Thru 10/14/11)	Yes (11/16/11)	Yes (12/9/11)	
CAN-0033	PRC-023-1 Transmission Relay Loadability Criteria Selection	PRC-023		x	Yes 6/8/12 (thru 7/27/12			
CAN-0034	EOP-002 R1, IRO-001 R2 and TOP-001 R1 Use of Authority Letters	EOP-002 IRO-001 TOP-001	R1 R2 R1	x	Yes 4/10/12 (Thru 5/7/12)	Yes (5/8/12)		
CAN-0038	PER-002 R4 Training Hours	PER-002	R4	x	Yes 4/10/12 (Thru 5/7/12)	Yes (5/8/12)		
CAN-0039	Filing DOE Form OE-417 Event Reports, EOP-004-1	EOP-004		x	Yes 9/23/11 (Thru 10/14/11)	Yes (11/11/11)	Yes (12/9/11)	
CAN-0040	BAL- 003 Frequency Response Calculation	BAL-003		x	Yes 11/2/11 (Thru 11/23/11)	Yes (12/9/11)	Yes (12/30/11)	
CAN-0043	PRC-005 Protection System Maintenance and Testing Evidence	PRC-005		x	Yes 11/2/11 (Thru 11/23/11)	Yes (12/9/11)	Yes (2/16/12 - Revised)	Revised CAN posted 2/16/12

NERC Compliance Application Notice Executive Tracking Summary

Revised: 8/6/2012

Further details regarding the individual documents may be found at: http://www.nerc.com/page.php?cid=3%7C22%7C354

CAN#	Project No. / Title	Associated Standard or Issue	Requirement	Advance Notice?	Posted for Comment?	Comments Posted?	CAN Issued?	Comments
CAN-0044	TOP-001 R1, R2 and R5 Operating Emergencies and Emergency Conditions	TOP-001	R1, R2, R5	x	Yes 6/8/12 (thru 7/27/12			

Acronyms:
CAN - Compliance Application Notice

NERC Reliability Standard Audit Worksheet (RSAW) Executive Tracking Summary

Revised: **11/19/2012**

Further details regarding the individual documents may be found at: http://www.nerc.com/page.php?cid=3|404

RSAW#	Title	Posted for Comment?	Comments Posted?	RSAW Issued?	Comments	
CIP-001-2a	Sabotage Reporting	x	x	10/13/2012		x
CIP-006-5	Physical Security of BES Cyber System	Yes (Thru 10/10/12)	x			
COM-002-2a	Communication and Coordination	Yes (Thru 4/30/12)	Yes (4/27/12)			
COM-003-1	Operating Personnel Communications Protocols	Yes (Thru 12/13/12)				x
EOP-001-2b	Emergency Operations Planning	x	x	10/13/2012		x
EOP-003-2	Load Shedding Plans	x	x	10/13/2012		x
EOP-005-2	System Restoration from Blackstart Resources	x	x	10/13/2012		x
EOP-006-2	System Restoration Coordination	x	x	10/13/2012		x
EOP-008-1	Loss of Control Center Functionality	x	x	10/13/2012		x
FAC-008-3	Facility Ratings	x	x	10/13/2012		x
FAC-013-2	Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon	x	x	10/13/2012		x
IRO-014-1	Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	x	x	10/13/2012		x
PER-005-1	System Personnel Training	Yes (Thru 4/30/12)	Yes (4/27/12)	Yes (8/10/12)		
PRC-023-2	Transmission Relay Loadability	x	x	11/15/2012		x

NPCC Regional Reliability Standards Executive Tracking Summary

Revised: **9/20/2012**

Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/UnderDev.aspx

Line No.	Regional Standard ID	Regional Reliability Standard Title	RSAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NPCC BOD Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
1	BPS-501-NPCC-01	Classification of Bulk Power System Elements (Withdrawn by RSC 8/07/09)	Yes (Thru 2/4/08)	NA	NA	NA	NA	NA	NA	NA	Withdrawn by RSC 8/07/09	Withdrawn
2	PRC-002-NPCC-01	Disturbance Monitoring	Yes (Thru 9/10/08)	Yes (Thru 10/24/09)	Yes (Thru 1/6/10)	Yes (1/6/10)	Yes (1/9/10)	Yes (11/4/10)	Yes (5/31/11)	Yes (10/20/11)	10/24/11 - Approved Standard posted publicly	Completed
3	PRC-006-NPCC-01	Automatic Underfrequency Load Shedding Program	Yes (Thru 8/25/08)	Yes (Thru 11/2/11)	Yes (Pre-ballot Thru 11/2/11)	Yes (11/18/11)	Yes (11/30/11)	Yes (2/9/12)	Yes (5/4/12)		- On 9/20/12 FERC issued a NOPR proposing to approve PRC-006-NPCC-1, Automatic Underfrequency Load Shedding. Comments on NOPR are due by 11/26/12.	Pending FERC Approval
4	BAL-002-NPCC-01	Regional Reserve Sharing	Yes (Thru 11/2/10)	Yes (Thru 12/16/11)	Yes (Thru 1/6/10)						Nomination Form posted - nominations due by 11/10/11	Under Development
5	PRC-012-NPCC-01	Special Protection Systems	Yes (thru 8/18/08)									On Hold

Acronyms;
RSAR- Regional Standards Authorization Request
RRS- Regional Reliability Standard
DT- Drafting Team
SC - NERC Standards Committee
TBD- To Be Determined
BOD- NPCC Board of Directors
BOT- NERC Board of Trustee

NPCC Document Open Process Executive Tracking Summary

Revised: **7/16/2012**

Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/opOther.aspx

Line No.	Type	Document	Description	Effective Date	Comments	Status
1	Criteria	A-01	Criteria for Review and Approval of Documents			
2	Criteria	A-10	Classification of BPS Elements			
3	Criteria	A-15	Disturbance Monitoring Equipment Criteria			
4	Guideline	B-01	NPCC Guide for the Application of Autoreclosing to the Bulk Power System			Open Process - comment period through 8/27/12
5	Guideline	B-12	Guidelines for On-Line Computer System Performance During Disturbances			
6	Guideline	B-25	Guide to Time Suynchronization			
7	Guideline	B-26	Guide for Application of Disturbance Recording Equipement			
8	Guideline	B-27	Regional Critical Asset Identification Methodology			
9	Guideline	B-28	Guide for Generator Sequence of Events Monitoring			
10	Procedure	C-00	Listing of NPCC Documents by Type			
11	Procedure	C-01	NPCC Emergency Preparedness Conference Call Procedures - NPCC Security Conference Call Procedures			
12	Procedure	C-05	Monitoring Procedures for Emergency Operation Criteria			
13	Procedure	C-07	Monitoring Procedures for the Guide for Rating Generating Capability			
14	Procedure	C-15	Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems			
15	Procedure	C-17	Procedures for Monitoring and Reporting Critical Operating Tool Failures			Open Process - Comment period ended 5/7/12
16	Procedure	C-21	Monitoring Procedures for Conformance with Normal and Emergency Transfer Limits			
17	Procedure	C-25	Procedure to Collect Power System Event Data			
18	Procedure	C-29	Procedures for System Modeling:Data Requirements and Facility Ratings			
19	Procedure	C-30	Procedure for Task Force on System Protection Review of Disturbances and Protection Misoperations			
20	Procedure	C-33	Procedure for Analysis and Classification of Dynamic Control Systems			Open Process - comment period ended 3/27/11
21	Procedure	C-36	Procedures for Communications During Emergencies			
22	Procedure	C-39	Procedure to Collect Major Disturbance Event Data			
23	Procedure	C-42	Procedure for Reporting and Reviewing System Disturbances			
24	Procedure	C-43	NPCC Operational Review for the Integration of New facilities			
25	Procedure	C-44	NPCC Regional Methodology and Procedures for Forecasting TTC and ATC			
26	Procedure	C-45	Procedure for Analysis and Reporting of Protection System Misoperations	5/25/2011	[C-45 was previously reserved for CO-12 Seasonal Assessment Methodology (previously proposed but not issued - information included in the CO-12 Working Group scope instead)]	
27	Criteria	A-03 (retired)	Emergency Operation Criteria		A3 retired	Directory #2 established
28	Criteria	A-05 (retired)	Bulk Power System Protection Criteria		A5 retired	Directory #4 established
29	Criteria	A-07 (retired)	Revise Critical Component Definition (Glossary of Terms)		To be retired - pending approval of Glossary	Retired 10/26/11 (correction)
30	Criteria	A-08 (retired)	NPCC Reliability Compliance and Enforcement Program		A-08 retired	CCEP-1 established
31	Guideline	B-21 (retired)	NPCC Guide for Analysis and Reporting of Protection System Misoperations		Superseded by C-45	Replaced by Procedure C-45
32	Guideline	B-22 (retired)	Guidelines for Implementation of the NPCC Compliance Program		B-22 retired	CCEP-1 established
33	Procedure	C-32 (retired)	Review Process for NPCC Reliability Compliance Enforcement Program		C-32 retired	CCEP-1 established
34	Criteria	A-02 (retired)	Basic Criteria for Design and Operation Of Interconnected Power Systems		A2 retired	Directory #1 established
35	Criteria	A-04 (retired)	Maintenance Criteria for Bulk Power System Protection		A4 retired 7/11/2008	Directory #3 established
36	Criteria	A-06 (retired)	Operating Reserve Criteria		A6 retired 12/2/2010	Directory #5 established
37	Criteria	A-11 (retired)	Special Protection System Criteria			Directory #7 established
38	Criteria	A-12 (retired)	System Restoration Criteria		A12 draft replaced by Directory #8 10/21/08	Directory #8 established
39	Criteria	A-13 (retired)	NPCC Inc. Verification of Generator Gross and Net Real Power Capability		A13 retired 12/22/2008	
40	Criteria	A-14 (retired)	Verification of Generator Gross and Net Reactive Power Capability		A14 retired 12/22/2008	
41	Guideline	B-02 (retired)	Control Performance Guide		B2 retired	Content transferred to Directory #5 App. 5
42	Guideline	B-03 (retired)	Guidelines for Inter-AREA Voltage Control		B3 retired	Replaced by Procedure C-40
43	Guideline	B-04 (retired)	Guidelines for NPCC Area Transmission Reviews		B4 retired	Content transferred to Directory #1 App.B

NPCC Document Open Process Executive Tracking Summary

Revised: **7/16/2012**

Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/opOther.aspx

Line No.	Type	Document	Description	Effective Date	Comments	Status
44	Guideline	B-05 (retired)	Bulk Power System Protection Guide		B5 retired	Content transferred to Directory #4 App. A
45	Guideline	B-06 (retired)	Automatic Load Shedding Employing Underfrequency Threshold Relays		B6 retired	Replaced by Guideline B-07
46	Guideline	B-07 (retired)	Automatic Underfrequency Load Shedding Program		B7 retired	Content transferred to Directory #4 App. A
47	Guideline	B-08 (retired)	Guidelines for Area Review of Resource Adequacy		B8 retired	Content transferred to Directory #1 App.D
48	Guideline	B-09 (retired)	Guide for Rating Generating Capability		B9 retired	Replaced by Criteria A-13 Document on July 18, 2007
49	Guideline	B-10 (retired)	Guidelines for Requesting Exclusions		B10 retired	Content transferred to Directory #1 App. E
50	Guideline	B-11 (retired)	Special Protection System Guideline		B11 retired	Replaced by Criteria A-11
51	Guideline	B-13 (retired)	Guide for Reporting System Disturbances		B13 retired	Replaced by Procedure C-42
52	Guideline	B-24 (retired)	Security Guidelines for Protection System IEDS		B24 retired	Content transferred to Directory #4 App. A
53	Procedure	C-03 (retired)			C3 retired	Replaced by Procedure C-36
54	Procedure	C-04 (retired)	Monitoring Procedure for Guides Inter-AREA Volt Control		C4 retired	Content transferred to Directory #1 App. G
55	Procedure	C-08 (retired)	Monitoring Procedures for Control Performance Guide		C8 retired	Content transferred to Directory #5 App. #5
56	Procedure	C-09 (retired)	Monitoring Procedures for Operating Reserve Criteria		C9 retired	Content transferred to Directory #5 App. #2
57	Procedure	C-10 (discontinued)			C10 discontinued	
58	Procedure	C-11 (retired)	Monitoring Procedures for Interconnected System Freq Response		C11 retired	Content transferred to Directory #5 App. #1
59	Procedure	C-12 (retired)	Procedure Shared Activation Ten Minute Reserve		C12 retired	Content transferred to Directory #5 Sect 5.8 & App. #4
60	Procedure	C-13 (retired)	Operational Planning Coordination		C13 retired	Content transferred to Directory #1 App. F
61	Procedure	C-14 (retired)			C14 retired	Procedure C-14 was incorporated in Procedure C-13
62	Procedure	C-16 (retired)	Procedure for Review of New or Modified BPS SPS		C16 retired	Content transferred to Directory #7 App.B
63	Procedure	C-18 (retired)	Procedure for Test & Analysis Extreme Contingencies		C18 retired	Content transferred to Directory #1 App.C
64	Procedure	C-20 (retired)	Procedures During Abnormal Operating Conditions		C20 retired	Content transferred to Directory #5 App. #3
65	Procedure	C-22 (retired)	Procedure for Reporting & Review Proposed BPS Protection Systems		C22 retired	Content transferred to Directory #4 App. A
66	Procedure	C-35 (retired)	NPCC Inter-Area Power System Restoration Procedure		C35 retired	Incorporated within Directory #8 System Restoration
67	Procedure	C-37 (retired)	Operating Procedures for ACE Diversity Interchange		C37 retired	Content transferred to Directory #5 Sect.5.11
68	Procedure	C-38 (retired)	Procedure for Operating Reserve Assistance			Content will be transferred to new Directory #5 Reserve
69	Procedure	C-40 (retired)	Procedures for Inter-AREA Voltage Control		C40 retired	Content transferred to Directory #1 App. G & Directory #2 App. B
70	Procedure	Cost Effectiveness Analysis Procedure - CEAP				Open Process - Comment period through 9/19/11
71	Glossary	NPCC Glossary of Terms				Open Process - Comment period through 9/12/11

Acronyms;

NPCC Directory Executive Tracking Summary

Revised: **10/12/2012** Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/opOther.aspx

Line No.	Document	Developed From	Description	Version Date	Phase	Task Force Review	Posted Open Process?	RCC Approval?	Full Membership Ballot?	Comments	Status
1	Directory #1	Criteria A-2	Design and Operation of the Bulk Power System	12/1/09 (V0)		TFCP(CP11) and TFCO (CO8)				Open Process posting expected in late 2012.	TFCP coordinating the overall Phase 2 reformatting of Directory #1. TFCO and TFSS also reviewing portions of the reformatted draft prior to the initial Open Process posting. TFCP expects to post Directory#1 for comment after the multi TF review in late 2012.
2	Directory #2	Criteria A-3	Emergency Operations	1/6/11 (V3)		TFCO					Phase 2 reformatting pending TFCO resources.
3	Directory #3	Criteria A-4	Maintenance Criteria for Bulk Power System Protection	6/3/09 (V1)		TFSP					Phase 2 reformatting pending TFSP resources.
4	Directory #4	Criteria A-5	Bulk Power System Protection Criteria	12/1/09 (V0)		TFSP				Open Process posting expected in early 2013.	TFSP reformatting Directory #4 pending RSC and CC review of TFSP request to insert compliance requirements in the draft in lieu of the standard Phase 2 format.
5	Directory #5	Criteria A-6	Reserve	12/2/10 (V0)		TFCO (CO1 and CO8)	Yes (Ballot Thru 10/11/12)	Yes (9/12/12)	Passed 10/11/12		
6	Directory #6		Regional Reserve Sharing		2				Passed 04/09/2012	Directory #6 approved by the NPCC Full Members in Phase 2 format in April 2012.	
7	Directory #7	Criteria A-11	Special Protection Systems	12/27/07 (V0)	2	TFSP	Yes (Comment Thru 11/12/12)				
8	Directory #8	Criteria A-12	System Restoration	10/22/10 (V1)		TFCO (CO11)					TFCO working group CO11 reviewing initial Phase 2 draft of Directory #8.
9	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	7/7/09 (V1)	2				Passed 12/28/11	Directory#9 Phase 2 reformatting complete December 2011.	
10	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	7/7/09 (V1)	2				Passed 12/28/11	Directory#10 Phase 2 reformatting complete December 2011.	
11	Directory #11										
12	Directory #12		Under frequency Load Shedding Program Requirements	1/6/11 (V2)			Yes (Thru 10/26/12)			NPCC will retire Directory#12 upon Regional Standard PRC-006-NPCC-1 Automatic UFLS receiving approvals in all regional jurisdictions.	

x

Acronyms;
MC - Members Committee
RCC - Reliability Coordinating Committee

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September 10, 2012

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: North American Electric Reliability Corporation
Docket No. FA11-21-000
Reply Brief of the North American Electric Reliability Corporation

Dear Ms. Bose:

In accordance with the procedural schedule established in the Commission's "Order on Procedures" issued June 4, 2012 in Docket No. FA11-21-000, the North American Electric Reliability Corporation (NERC) hereby submits the "Reply Brief of the North American Electric Reliability Corporation" in this docket.

This filing consists of: (1) this transmittal letter, and (2) the Reply Brief of NERC, which are submitted in a single electronic file.

Please contact the undersigned if you have any questions concerning this filing.

Respectfully submitted,

/s/ Owen E. MacBride
Owen E. MacBride

Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
Before the
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. FA11-21-000**

REPLY BRIEF OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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September 10, 2012

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Appendix A: Status of Agreement on Audit Staff's Recommendations

Pursuant to the Order on Procedures issued June 4, 2012, in this proceeding, *N. Am. Elec. Reliability Corp.*, 139 FERC ¶ 61,179 (2012), the North American Electric Reliability Corporation hereby submits this Reply Brief to the Response Brief of the Office of Enforcement Staff ("OE," "Staff" or "Audit Staff") which was submitted on August 20, 2012.[1]

I. Executive Summary

The disagreements between NERC and the Audit Staff continue to narrow in resolving minor differences, but have hardened with respect to the major differences.[2] NERC's Initial Brief accepted 20 of Audit Staff's 42 recommendations and proposed alternative approaches to many of the remaining recommendations. In response, the OE Brief proposes to accept two of NERC's alternative recommendations without change and 9 of NERC's alternative recommendations with conditions or limited modifications. NERC agrees with 7 of those 9 further modified recommendations, thereby leaving 29 of the 42 recommendations undisputed.[3] Of the remaining 13 recommendations, the text of 12 recommendations is disputed and there is disagreement on how to implement one recommendation.[4] In contrast to this narrowing of what were minor differences, OE did not offer any concessions on the core areas of disagreement that led NERC to contest the audit – Audit's Staff's effort to micromanage the form of compensation

[1] *Response of Office of Enforcement Staff to the Initial Brief of the North American Electric Reliability Corporation*, filed August 20, 2012 ("OE Brief" or "Response Brief"). A joint brief was also filed by the American Public Power Association, the Edison Electric Institute, the Electric Power Supply Association, the Electricity Consumers Resource Council, the Large Public Power Council, the National Rural Electric Cooperative Association and the Transmission Access Policy Study Group (collectively "Trade Associations"), and brief comments were filed by the California Public Utilities Commission ("CPUC"). The joint brief of the Trade Associations supports NERC's position on all issues addressed by the Trade Associations. The CPUC's comments state generally that appropriate recommendations should be adopted but do not set forth specific arguments in support of any recommendations.

[2] Appendix A to this Reply Brief provides the current status of agreement on the 42 recommendations.

[3] Based on the OE Brief, there is disagreement on how to implement one of the recommendations (Recommendation 1) as to which NERC and OE agree on the text of the recommendation.

[4] For Recommendation 37, on which there is a disagreement as to implementation, NERC is proposing in this Reply Brief a change in its originally-proposed implementation, which NERC hopes will meet OE's concerns about implementation. *See* §III.D below.

for the Board of Trustees, impose cumbersome pre-approval restrictions on the expenditure of funds, and impose unnecessary time recording burdens on NERC and its employees. Similarly, with respect to the disputed factual findings, OE also refused to modify any of the findings and, in a break from past practice, argues that the Commission must resolve every factual dispute even if the findings relate to unopposed recommendations.

NERC is disappointed that the disputes with Audit Staff remain so fundamental, but is pleased that the June 4 Order provides fair procedures for resolving them. Both NERC and OE have had an adequate opportunity to brief the issues to the Commission on an open and transparent basis and, importantly, other interested parties have that same opportunity. In this regard, the Joint Brief of the Trade Associations – whose load-serving members are "responsible for payment of their allocated share of the NERC budget" and therefore "have a very strong interest in NERC's activities" (Trade Assoc. Br. at 2) – provides strong support for NERC's positions. Among the key points made by the Trade Associations are the following:

- *Standard for Oversight.* The Trade Associations disagree with Audit Staff's proposal to adopt a "more intrusive form of regulation" with respect to NERC than it does for public utilities under Part II of the FPA (*id.* at 5). The Trade Associations "urge the Commission to step back and carefully review the Audit Report, separating legitimate concerns regarding expenditures and internal controls from the Audit Report's no doubt well-intentioned but nonetheless intrusive *post hoc* review of NERC management decisions," noting that, "[i]n many instances, there is no one right answer to a management issue" and "[i]n such cases, management decisions should be given appropriate deference in the absence of any showing of lack of diligence or inattention to relevant factors" (*id.* at 7).
- *"Redirection" of Funds.* The Trade Associations disagree with Audit Staff's contention that NERC should obtain pre-approval from the Commission for any significant changes

in budget needs within the budget year, stating that "the compromise NERC has offered in this subject matter area is sufficient and should be accepted by the Commission" and that "NERC must retain flexibility during the course of a budget year to redirect funds as management deems necessary to carry out NERC's ongoing functions" (*id.* at 10).

- *Board Compensation.* The Trade Associations disagree with Audit Staff's argument that NERC must consider returning to a more variable method of compensation for the Board of Trustees unless it can justify a change to a fixed annual retainer method, stating "[t]he Trade Associations believe that so long as the overall compensation levels for NERC Trustees are not out-of-line when compared to other not-for-profit organizations with similar specialized, critical infrastructure missions and the need for board members with specialized experience and qualifications, *there is no need for the Commission to make any recommendations in this area*" (*id.* at 6) (emphasis added).
- *Scope of Section 215.* The Trade Associations disagree with Audit Staff's narrow view of Section 215, noting that "NERC's statutory mandate extends beyond bare-bones reliability standards-drafting and compliance/enforcement activities, and the Commission has recognized this on multiple occasions" (*id.* at 8) and, with respect to the process for addressing the issue, they agree with NERC that "the better forum in which to resolve such scope issues is the budget process itself" where "the Commission and interested industry participants would have the opportunity to debate and resolve in advance which proposed NERC activities are (or are not) within the scope of Section 215." *Id.*

NERC agrees with the views of the Trade Associations on these issues. As the Trade Associations note on several occasions in their Joint Brief, NERC's budget processes and policies are more open than they are for any other entity the Commission regulates, giving the Trade Associations (and Commission staff, if it so desires) multiple opportunities for input. In addition, the Commission's formal review of NERC's annual budget provides yet another

opportunity to evaluate those policies and procedures. This audit is therefore not the only opportunity for the Commission to review NERC's policies and procedures, which continue to evolve and strengthen each year.

With respect to the key differences that remain concerning the recommendations, they are essentially the same as described in NERC's Initial Brief. NERC continues to object to the "intrusive form of regulation" (Trade Assoc. Br. at 5) reflected in three groups of Audit Staff's recommendations.

First, OE continues to argue that NERC must receive prior Commission approval for any "significant" change in its budget expenditures, even if the total funding required through assessments remains within the amount approved by the Commission. NERC has previously explained why this proposal is unworkable and would severely hamper NERC's ability to respond to emerging reliability threats and changing priorities. NERC proposed either to file its quarterly budget variance reports with the Commission for informational purposes or to submit the variance reports to Commission budget staff. NERC Initial Brief at 30-31. Further, NERC has now adopted and submitted to the Commission a detailed Working Capital and Operating Reserves Policy that includes specific internal approval requirements, at the management, Board committee and Board levels, for spending funds from Operating Reserves on unbudgeted activities or on budgeted activities needing additional funding.[5] (*See* §III.A below.) Regrettably, however, OE has not offered any concessions, and continues to advocate a recommendation that could result in NERC making potentially multiple budget filings every year – despite the fact that the Commission's own regulations do not require any additional filings unless the total amount of assessment funding required has increased. OE also fails to address the practical problems with its proposal given the time lags associated with preparing budget filings on an open and transparent basis and the time required for the Commission to review and act on filings.

[5] NERC's Initial Brief at 28-30 discussed development of this new Policy.

Worse yet, OE's proposal would place the Commission in the untenable position of having to essentially forbid NERC from addressing any new reliability threats not identified in the budget unless it had completed a cumbersome mid-year budget process to allocate funds to those threats. As the Trade Associations emphasize, "NERC must retain flexibility during the course of a budget year to redirect funds as management deems necessary to carry out NERC's ongoing functions." Trade Assoc. Br. at 10.

Second, OE – although emphasizing that the Audit Report did not find NERC's Board compensation to be excessive[6] – continues to insist on forcing NERC's Board of Trustees to consider adopting a method of Trustee compensation that is tied to the amount of time each Trustee spends on NERC activities. The Commission should decline to adopt this position because it is the essence of micromanagement. Further, the audit criteria cited in the Audit Report (under "Pertinent Guidance" at page 56 of the Audit Report) do not support Audit Staff's recommendations on Board compensation. The Audit Report's recommendations on Trustee compensation do not provide additional "transparency" and are not required by any Commission regulation or requirement. Nor are the recommendations necessary to ensure consistency with NERC's own policies. To the contrary, the Audit Report's recommendations on Board compensation rest solely on the Audit Staff's unwavering belief that the Board of Trustees should be forced to bill hours and should be paid for their services that way. The Commission should reject this position and adopt NERC's alternative recommendation, under which the Board compensation plan will continue to be evaluated each year in the same open and transparent process that is used today.

Third, OE continues to argue that NERC's employees should be forced to record their time on a "project-specific" basis and that all NERC expenses must be accounted for on that

[6] OE Brief at 62. Audit Staff also made it clear that it was not taking issue with the level of Board compensation *Audit Staff Comments to NERC Response to Draft Audit Report*, Docket No. FA11-21-000, May 4, 2012 (Appendix B to the Final Audit Report) at B-12 ("Audit Report Appendix B").

basis. The Commission should decline this recommendation for several reasons. First, OE has still not explained what it means by "project-specific," leaving it entirely unclear whether NERC must create scores or even hundreds of new time and expense account numbers for the myriad activities performed by NERC employees. Second, Audit Staff's recommendation would create more costs than it would save, by imposing a cumbersome and expensive new process that is not necessary for the effective management of NERC. Third, OE cannot identify any audit criteria that would necessitate this level of micromanagement of NERC's operations. The Commission should therefore adopt NERC's proposal to provide greater granularity in its time and expense reporting systems and to evaluate over time whether further granularity would save costs (rather than increase them) on a net basis and support effective management.

Finally, this Reply Brief also addresses the disputes regarding the Audit Report's factual findings. NERC has sought to keep this section brief, however, reflecting the fact that the OE Brief simply recites for the most part statements from the Audit Report, rather than containing detailed rebuttal to NERC's responses in its Initial Brief.

II. The Appropriate Legal Standards and Procedures

A. The Commission's Oversight Role

Recognizing that the ERO's role "is unique and that the Commission has an important oversight responsibility with respect to the ERO," NERC has suggested that the Commission, in resolving the disagreements that have arisen in this case, distinguish between effective oversight and micromanagement in discharging this important responsibility:

> Effective oversight of NERC implicates two primary criteria. First, the Commission should ensure that NERC's Board and management have adopted reasonable *processes* for ensuring that its budgetary expenditures and controls are reasonable. Second, the Commission should ensure that there is adequate *transparency* with respect to those processes and the related expenditures. By contrast, micromanagement would go one step further and involve the Commission in second-guessing the *substantive* decisions of NERC's Board or management in exercising its discretion with respect to its budget controls and processes. (NERC Initial Brief at 15; emphasis in original.)

NERC also supported this recommendation as consistent with longstanding Commission precedent. Managers of public utilities regulated under Part II of the Federal Power Act have "broad discretion" in conducting their business affairs and are entitled to a "presumption of prudence."[7] Similarly, the Commission has declined to micromanage the decisions of not-for-profit independent transmission system operators ("ISOs") and regional transmission organizations ("RTOs"):

> If the RTO or ISO board is well-informed about the needs of customers and various stakeholders, it will set criteria for performance, appropriate goals and targets for the organization and its management and institute measures for achieving those targets. *By focusing our requirements on having a well-informed board, we decline to intrude further into board prerogatives regarding management compensation.*[8]

In response, OE argues for a more invasive oversight role. OE argues that these longstanding precedents should not be followed here because they would "substantially limit the Commission's ability to oversee the ERO." OE Brief at 10. OE argues that these precedents "ignore NERC's unique role as the Commission-certified ERO and the Commission's special responsibility to promote reliability of the bulk-power system through ERO oversight." *Id.* Similarly, OE argues that "the Commission's oversight of ERO operations cannot be compared to its oversight of public utilities or ISOs/RTOs in light of the Commission's special responsibility to ensure the ERO performs its unique statutory functions." *Id.* at 12. To discharge this "special" and "unique" role, OE therefore recommends that "the Commission should independently measure the Audit Report's findings and recommendations based on the reasonableness of their evidentiary support and by their consistency with the Commission's statutory authority to oversee the ERO." *Id.* at 12-13.

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[7] *New England Power Co.,* 31 FERC ¶ 61,047 at 61,084, *reh'g denied*, 32 FERC ¶ 61,112 (1985), *aff'd sub nom.*, *Violet v. FERC,* 800 F.2d 280 (lst Cir. 1986).

[8] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64100 at P 561 (Oct. 28, 2008), FERC Stats. and Regs. ¶ 31,281 (2008), *order on reh'g*, Order No. 719-A, 74 Fed. Reg. 37776 (Jul. 29, 2009), FERC Stats. and Regs. ¶ 31,292 (2009), *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009) (emphasis added).

NERC agrees that its role is "unique" (NERC Initial Brief at 15) because there is only one ERO. But the fact that NERC is unique does not mean the Commission should adopt a more invasive form of oversight than has been applied for decades to other regulated entities. The Commission's longstanding precedents that decline to micromanage the decisions of public utilities and ISOs/RTOs are sound. Management and board decisions must be made in real time using the information available at the time and their experience in weighing the various factors that go into those decisions, not *post hoc* by auditors or parties using a litigation record compiled over the course of months.

Moreover, OE is entirely vague on what its proposed alternative standard should be. For example OE argues that the Commission should "independently measure" Audit Staff's findings against the evidence and ensure "consistency with the Commission's statutory authority" (OE Brief at 12-13), but NERC has not suggested anything to the contrary. Moreover, although OE strenuously objects to NERC's proposal that the Commission focus on procedures and transparency, OE actually appears to embrace this standard by repeatedly emphasizing that its main objective was to increase "transparency." *See, e.g.*, OE Brief at 4 (arguing that the purpose of the audit was to "assess and improve NERC's transparency" and that there must be "accurate and granular information" to ensure "[t]rue budget transparency"); *id.* at 5 (the recommendations are intended to "improve the transparency and accuracy of NERC's budget process").

NERC therefore recommends that the Commission adopt its proposal with respect to the appropriate standard for oversight. It is consistent with decades of practice and is supported by a significant group of stakeholders in this proceeding. The Joint Brief of the Trade Associations correctly states that Audit Staff's "more intrusive form of regulation" (*id.* at 5) would "enmesh the Commission in NERC's management decision-making in a manner that would substantially hamper needed flexibility." *Id.* at 3. The Trade Associations also note that this invasive role is not contemplated by Section 215:

> [T]he statute contemplates that the Commission will review NERC's rules for allocating reasonable costs in connection with certification (and potential decertification) of the ERO, and that oversight of its costs is for the purpose of assuring that the ERO is complying with statutory and regulatory criteria. This framework plainly places primary authority for the oversight of NERC's expenditures with its governing board, and suggests a substantial degree of deference to the ERO, absent evidence that the organization is failing to accomplish statutory and regulatory objectives. (*Id*. at 5)

OE's more intrusive form of regulation also ignores the public nature of NERC's entire budget process and the fact that it is more open than for any other regulated entity and therefore cannot possibly support a more invasive standard of oversight. As NERC explained in its Initial Brief, the process by which NERC's develops its budget is open for public review and comment by those who are responsible to pay the expenses:

> NERC's current annual process for developing its business plan and budget and those of the Regional Entities is extremely open and transparent. It includes posting of NERC's goals and objectives and the NERC and Regional Entity common business plan and budget assumptions for stakeholder comment, posting of drafts of the NERC and Regional Entity business plans and budgets for stakeholder comment, and presentation and discussion of the proposed business plans and budgets at open meetings of the Finance and Audit Committee ("FAC") of the NERC Board, the Member Representatives Committee ("MRC"), and the full Board. Stakeholders have the opportunity to listen to and participate in all of these meetings and to attend the Board meetings. NERC holds meetings and conference calls with stakeholders and stakeholder groups during the budget development process to discuss the draft budgets and receive comments. NERC and the Regional Entities also meet with Commission budget staff to review drafts of the business plans and budgets. (NERC Initial Brief at 18-19; footnotes omitted.)

In addition to this open process for budget *preparation*, the Commission has the opportunity every year to review and approve NERC's proposed budgets. The Commission has used this review on multiple occasions to require changes in priorities, including with respect to staffing concerns. For example, in its order on NERC's 2009 Business Plan and Budget, the Commission expressed concern about the adequacy of NERC's budgeted staffing for the Reliability Standards and Reliability Assessment and Performance Analysis programs and for the event analysis and compliance investigation functions within the Compliance program to carry out their respective responsibilities, and directed NERC to address these concerns in a

compliance filing.[9] In response, NERC submitted a compliance filing in which it reported that it was adding staff and/or consulting resources in each of these programs and instituting process changes in the Reliability Assessment and Performance Analysis program to address the Commission's concerns.[10] Therefore, this audit is not the Commission's only opportunity to review NERC's resources, policies and procedures, which further counsels against the intrusive standard of oversight reflected in the Audit Report.

B. Clear and Objective Audit Criteria

Compounding the problems presented by OE's invasive form of oversight is the fact that OE does not even ground its recommendations on clear or objective audit criteria. Unlike the normal compliance audit, there were no specific, Commission-approved criteria to apply in this case.[11] The Audit Report conceded this to a limited degree, stating that, "unlike the more common compliance audit, [the NERC audit was] designed to *assist* the subject in improving its performance and to facilitate decision-making by those charged with the responsibility to oversee

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[9] *North American Electric Reliability Corp.*, 125 FERC ¶ 61,056 (2008), at PP 21-28 and 37.

[10] *Compliance Filing of the North American Electric Reliability Corporation in Response to October 16, 2008 Order on 2009 Business Plans and Budgets*, filed December 15, 2008 in Docket Nos. RR08-6-000 and RR07-14-001, at 2-18 and 34-36. The Commission accepted NERC's actions on these issues, as reported in the compliance filing, in an order issued on July 16, 2009. *North American Electric Reliability Corp.*, 128 FERC ¶61,025 (2009) at PP 17-21.

[11] *Revised Policy Statement on Enforcement*, 123 FERC ¶ 61,156 at P 14 (2008) ("[t]he Divisions of Audits within the Office of Enforcement helps ensure compliance with the Commission's statutes, regulations, and orders by conducting a wide array of audits of jurisdictional entities"); 18 C.F.R. § 41.1(a) (audit report under FPA Part II focuses on "findings that the audited person has not complied with a requirement of the Commission"); *Report on Enforcement*, Docket No. AD07-13-000, pp. 26-27 (November 14, 2007) (OE's "audits provide the Commission with *an objective assessment of industry compliance* with various aspects of the Commission's rules, regulations, and statutory requirements") (emphasis supplied); *Rules Concerning Certification of the Elec. Reliability Org.; and Procedures for the Establishment, Approval, and Enforcement of Elec. Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, FERC Stats. & Regs. ¶ 31,204 at P 773 ("[w]e contemplate that a compliance audit of the ERO would typically involve an examination of the ERO's ongoing compliance with statutory and regulatory criteria for certification and its performance in carrying out its responsibility to oversee the compliance with and enforcement of Reliability Standards"), *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,202, *appeal dismissed sub nom., N.Y. Indep. Sys. Operator v. FERC*, No. 06-1185 (D.C. Cir. Sept. 29, 2006); *see also* 16 U.S.C. § 824o(e)(5) ("[t]he Commission may take such action as is necessary or appropriate against the ERO . . . *to ensure compliance with a reliability standard or any Commission order* affecting the ERO . . . .") (emphasis supplied).

or initiate corrective action."[12] But Audit Staff does not consider its recommendations mere "assistance;" it demanded that NERC accept them or proceed to litigation.

The OE Brief now contends, however, that it applied "clear and objective" criteria to assess NERC's performance. OE argues that "staff evaluated NERC's performance in light of FPA Section 215 and 18 C.F.R. part 39, as well as NERC's own internal policies and procedures." OE Brief at 4. OE also argues that NERC must "be held accountable for operating in accordance with rules approved by the Commission and . . . budget-related policies, procedures and controls." *Id.* at 4-5. Finally, as indicated, OE argues that a central purpose of the audit was to increase "transparency." *Id* at 4.

NERC has no objection to being held accountable to the "criteria" mentioned by OE, but none of them support OE's disputed recommendations. Consider, for example, the disputes over NERC's current method of Board compensation. The only audit criteria cited in the Audit Report for this topic are (1) Section 215(c)(2) of the FPA, which specifies that to be certified, the ERO candidate must have "rules that allocate equitably reasonable dues, fees, and other charges among end users for all activities under this section;" and (2) 18 C.F.R. §39.4(b), which specifies the required contents of NERC's annual budget filings. OE Brief at 56 ("Pertinent Guidance"). Yet OE does not contend that NERC has violated Section 215, and does not contend that NERC has violated 18 C.F.R. §39.4(b) (or any other provision of Part 39), in using its current method of Board compensation. Nor does OE contend that there was insufficient transparency in the adoption of the current method of Board compensation. Rather, OE takes issue with the substantive decision itself, arguing that NERC's decision to adopt a fixed annual retainer method of Trustee compensation was not adequately supported. OE Brief at 62. This is the very type of *post-hoc*, micromanagement that is clearly an inappropriate form of oversight and, even more fundamentally, lacks any clear or objective criteria by which to exercise that oversight. It is

[12] Audit Report Appendix B at B-4 (emphasis added).

subjective not objective. OE's position simply reflects Audit Staff's preference for one method of Trustee compensation over another.

The same problems underlie OE's recommendations regarding the supposed "redirection" of budgeted funds. OE has argued that NERC must receive prior Commission approval of any "significant" deviation from its approved annual budget, thereby creating the possibility of multiple budget filings every year that leave NERC unable to respond effectively to emerging reliability threats or changes in priorities while those filings are processed.[13] OE rejected NERC's alternative recommendation that would require NERC to continue to increase the transparency of its budgets, file quarterly budget variance reports with the Commission and develop enhanced policies and procedures concerning the expenditure of unspent funds budgeted for one activity on another, emerging activity,[14] even though OE's position was unsupported by any clear or objective criteria. Indeed, the *only* Commission-approved criteria that exist make clear that additional filings are not required unless NERC needs to collect an additional assessment from load-serving entities, not for adjusting priorities and expenditures within the approved budget and assessment funding. 18 C.F.R. §39.4(d) ("On a demonstration of unforeseen and extraordinary circumstances requiring additional funds prior to the next Electric Reliability Organization fiscal year, the Electric Reliability Organization may file with the Commission for authorization to collect a special assessment").

OE's position is even more troubling when combined with OE's demand that the Commission resolve all disputed findings in its favor – even where they relate to recommendations that are unopposed. This is a clear break from past practice where audited entities can accept Audit Staff's recommendations without being bound by findings with which they disagree. *Sw. Power Pool, Inc.*, 126 FERC ¶ 61,045 at PP 21-22 (2009) (recognizing

[13] In addition, preparing and submitting such filings would be additional administrative costs for NERC.

[14] NERC has in fact developed, adopted and submitted such enhanced policies and procedures, in its new Working Capital and Operating Reserves Policy. *See* §III.A below.

significant disputes over audit staff's findings, but declining to address them because of agreement on recommendations); *Entergy Services, Inc.,* Letter Order of Norman C. Bay, Oct. 29, 2010, at 1 ("Entergy agrees, in whole or in part, with all 32 recommendations of the Audit Report. Although Entergy disagrees with many factual findings, it 'does not believe that it would be productive to litigate them given that Entergy has agreed to adopt all of Audit Staff's recommendations.' I hereby approve the recommended corrective actions."). It is even contrary to the practice in formal investigations, where settlements that require mitigation plans *do not* require the settling party to accept Enforcement Staff's findings. *See, e.g., In re PacifiCorp,* 137 FERC ¶ 61,176 (2011) (adopting stipulation that contrasts "stipulated facts" to which all parties agree with Enforcement Staff's "findings" regarding alleged violations that did not require acquiescence by party subject to the investigation).[15] NERC believes that its position on all the disputed findings is correct and should be adopted by the Commission if it decides to resolve all of them, but we continue to be surprised by OE's overly litigious approach to this case that would require the Commission to resolve findings over myriad issues even where there are no disputes over the associated recommendations.

III. Remaining Disputed Recommendations

The Audit Report contained 42 recommendations. Based on (i) the recommendations accepted by NERC in its Initial Brief, and (ii) the NERC revised versions of recommendations that were accepted by OE, without condition, in the OE Brief, NERC and OE are in agreement on 22 recommendations, although there is one recommendation (Recommendation 1) as to which NERC and OE disagree on how to implement it. There are an additional nine Audit Staff recommendations which were modified by NERC that OE states in its Brief are acceptable to OE

[15] In this regard, NERC calls to the Commission's attention OE's assertion that because NERC has accepted Audit Report Recommendation 37, it must be accepting the validity of the underlying audit findings. OE Brief at 76. OE's characterization is both erroneous and imprudent. The Commission should consider whether it wants to be sending a message to future auditees (under all provisions of Commission authority) that if they accept and agree to implement an audit recommendation, they will be deemed to have agreed with the validity of the underlying audit findings.

either subject to conditions, or with slight modifications. In this Reply Brief, NERC accepts the proposed conditions or modifications as to seven of those nine recommendations.[16] For Recommendation 37, OE does not dispute NERC's text for the recommendation, but OE does not agree with NERC's proposed implementation of the recommendation. In §III.D below, NERC accepts OE's position on implementation of this recommendation. As a result, there are 29 agreed recommendations, 12 recommendations disputed as to their text, and one recommendation disputed as to how it should be implemented. The agreed recommendations include all the recommendations relating to 7 of the 11 topics addressed in the Audit Report:

- NERC Oversight of the Regional Entities' Budgets
- Employee Compensation
- Standard for Determining the Reasonableness of Expenses
- Employee Entertainment
- Retirement Plans
- NERC Critical Infrastructure Protection Program
- NERC as the Electric Sector – Information Sharing and Analysis Sector.

As noted above, for one of the remaining 13 recommendations (Recommendation 1), the text of the recommendation is not disputed but OE does not agree with NERC's proposed implementation of the recommendation. This leaves only 12 of the original 42 recommendations for which the text is disputed (Recommendations 2, 3, 4, 9, 12, 13, 25, 26, 27, 28, 29, 38.) In the subsections below, NERC demonstrates why the Commission should adopt NERC's version of these 12 recommendations with disputed text and NERC's proposed implementation of the one recommendation for which there is disagreement on implementation.

A. NERC Budget Process/ "Redirection" of Funds

Issues remain with respect to four of the five Audit report recommendations on the topic of "NERC Budget Process." OE and NERC agree on the text of Recommendation 1 but disagree as to its implementation. OE and NERC disagree on the text of Recommendations 2, 3 and 4.

[16] *See* §III.E below.

Recommendations 1, 2 and 3 are discussed in this section and Recommendation 4 is discussed in §III.B below.[17] Recommendation 5 is agreed.

Recommendation 1. The remaining dispute concerning this recommendation relates to its implementation, not to its text. In its Initial Brief, NERC stated that it would file a new Working Capital and Operating Reserves Policy that would implement this recommendation as part of NERC's upcoming 2013 Business Plan and Budget filing. NERC Initial Brief at 28-29. OE, however, believes that the new Policy should be filed in a separate compliance filing outside of the business plan and budget process. OE Brief at 31-32.

OE and NERC agree on the text of this recommendation as originally presented in the Audit Report, that NERC should "Establish more robust procedures and controls over NERC's use of working capital reserves." In its Initial Brief, NERC stated that it was developing a new Working Capital and Operating Reserves Policy, which had been posted for stakeholder input, and upon obtaining NERC Board approval of the new Policy, would include it in NERC's 2013 Business Plan and Budget filing due August 24, 2012.[18] In its Response Brief, OE states that NERC should not submit its proposed Working Capital and Operating Reserves Policy as part of its Business Plan and Budget filing, but rather in a separate compliance filing. OE's reasons are that (i) the Commission has only 70 days to review and approve NERC's annual business plan and budget filings, and (ii) stakeholders' opportunity for comment on the new Policy should not be truncated or rushed. (OE Brief at 31-32.)

However, because the new Working Capital and Operating Reserves Policy had been through a stakeholder review process and received the approval of the NERC Board Finance and

[17] Although Recommendation 4 is presented in the Audit Report in the section on NERC Budget Process, it does not relate to the topic of "redirection" of budgeted funds to new activities and controls on the use of reserves that is the subject matter of Recommendations 1, 2 and 3. Rather, Recommendation 4 pertains more directly to NERC's Time Reporting and Accounting Systems, similar to Recommendations 9-15.

[18] As discussed below, the new Working Capital and Operating Reserves Policy also addresses, in part, Recommendations 2 and 4.

Audit Committee ("FAC") and the full NERC Board, NERC included the new Policy as Exhibit C of its 2013 Business Plan and Budget that was filed with the Commission on August 24, 2012 (Docket No. RR12-13-000). NERC also developed its proposed Working Capital and Operating Reserves amounts for 2013, as reflected in the budget filing, based on the new Policy. The new Working Capital and Operating Reserves Policy:

- Defines Working Capital Reserves as the amount NERC needs to meet projected annual cash flow requirements and any cash balance requirements under the terms of any loan, credit or other agreements to which NERC is a party. The amount of Working Capital Reserves needed for these purposes is to be budgeted and justified each year separately from Operating Reserves. Funds needed for contingencies are not considered part of Working Capital Reserves
- Establishes three separate Operating Reserve accounts, for (i) known contingencies for which timing and amount are uncertain, (ii) unknown contingencies, and (iii) excess funds generated by the System Operator Certification Program.
- Specifies that the amounts in the first two Operating Reserves accounts are to be separately budgeted and justified each year; amounts accumulated in the third account are to be used solely for purposes of the System Operator Certification Program. Further, the budget for the known contingencies account must state the specific contingencies for which provision is being made and specify the range of potential expenditures for each contingency.
- Establishes guidelines and authorities (management, Board committee and Board approval requirements) to access funds in each of the Working Capital and Operating Reserves accounts and to use these funds for activities in excess of the amounts budgeted for the activities.
- Establishes authorities (management, Board committee and Board approval requirements) to hire personnel in excess of the total staffing levels in the approved business plan and budget.

NERC believed that it was important to proceed to develop the new, more detailed Policy and to use it in developing its 2013 budget. NERC submits that the Working Capital and Operating Reserves Policy is sufficiently detailed, and sufficiently explained in the 2013 Business Plan and Budget filing, that the Commission will be able to evaluate it in the course of reviewing the Business Plan and Budget filing. The Commission, of course, has the ability, in its order on the 2013 Business Plan and Budget, to direct NERC to provide more explanation or justification for the Policy in a compliance filing in that proceeding.

With respect to opportunity for stakeholder review of and input to the new Working Capital and Operating Reserves Policy, the proposed Policy was included in Draft #2 of the 2013 Business Plan and Budget, which was posted on NERC's Website for stakeholder comment on June 4, 2012, more than 60 days in advance of the NERC Board meeting at which the 2013 Business Plan and Budget, including the new Policy, was presented to the Board for approval.[19] Only one set of stakeholder comments relating to the proposed Policy was submitted. Those comments were submitted by the Ontario Independent Electricity System Operator ("IESO"). Thus, no stakeholders operating under the jurisdiction of the Commission submitted comments concerning the Policy. Further, the IESO comments were not directed to the Working Capital and Operating Reserves Policy itself, but rather only to the amounts that Draft #2 of the Business Plan and Budget specified would be included in certain of the Working Capital and Operating Reserves accounts.[20] Additionally, stakeholders have the opportunity to submit comments to the Commission on NERC's new Working Capital and Operating Reserves Policy during the comment period the Commission has established for the 2013 Business Plan and Budget in Docket No. RR12-13-000.[21]

OE's position on implementation of Recommendation 1 is inconsistent with the focus of the "performance audit" (according to Audit Staff) as a means to identify areas in which the entity's processes and operations can be improved going forward (*see* §II.B above). Audit Staff identified what it perceived to be a weakness in NERC's current operations and made a recommendation for improvement. Audit Staff and NERC agree on the text of the

[19] NERC sent notice that Draft #2 was posted for comment on the NERC Website to a broad distribution list of interested persons and entities, by e-mail.

[20] The text of the IESO comments is provided in Attachment 12 to NERC's 2013 Business Plan and Budget filing in Docket No. RR12-13-000. After considering the IESO comments and other input on this topic, NERC reduced the amounts included in certain of the Working Capital and Operating Reserves accounts in its final filed 2013 Business Plan and Budget from the amounts indicated in Draft #2.

[21] On August 27, 2012, the Commission issued a notice in Docket No. RR12-13-000 setting the public comment period on NERC's 2013 Business Plan and Budget filing to run through September 14, 2012.

recommendation. NERC has expeditiously implemented the recommendation by developing a new Working Capital and Operating Reserves Policy as part of the process of developing its 2013 budget, including providing opportunity for stakeholder input on the proposed Policy and obtaining Board of Trustees approval. NERC incorporated the new Policy into the development of the Working Capital and Operating Reserves amounts in its 2013 budget. The Policy has been included as part of NERC's 2013 Business Plan and Budget that has been filed with the Commission. What could be more responsive? In contrast, under OE's approach, implementation of a new policy on Working Capital Reserves would be delayed until at least after (i) briefing in this docket is completed, (ii) the Commission issues its order in the docket, (iii) NERC makes a compliance filing, which would include its proposed Policy responsive to Recommendation 1, at some date following issuance of the order, and (iv) the Commission issues an order on the compliance filing.

Accordingly, NERC submits that its new Working Capital and Operating Reserves Policy, which addresses agreed Recommendation 1, can be adequately reviewed, and any adjustments the Commission finds necessary can be addressed, in the context of NERC's 2013 Business Plan and Budget filing, and that a separate filing and proceeding to review the new Policy is not needed.

Recommendation 2. Audit Report Recommendation 2 is:

> Develop a transparent process that permits the Commission, the BOT [NERC Board] and stakeholders opportunity to review the expenditure of funds approved for specific statutory activities to be redirected to unbudgeted activities, and develop and obtain Board approval of enhanced guidelines governing such expenditures, including criteria for determining when Board and Commission approval is required.

NERC proposes to revise Recommendation 2 to:

> Continue to make improvements in budget transparency that informs the Commission, the Board and stakeholders concerning the expenditure of funds approved for specific budgeted activities on unbudgeted activities, and develop and obtain Board approval of enhanced guidelines governing such expenditures,

> including criteria for determining when Board approval is required. (NERC Initial Brief at 27.)

The only meaningful difference between the two versions of Recommendation 2 is OE's insistence that in at least some circumstances, NERC should be required to obtain Commission approval before initiating "significant unbudgeted discretionary projects" (OE Brief at 29-30). As NERC has pointed out, the Commission's regulations already specify when NERC must obtain Commission approval for expenditures or activities between annual budget filings: "On a demonstration of unforeseen and extraordinary circumstances requiring additional funds prior to the next Electric Reliability Organization fiscal year," NERC may file a request for authorization to collect a special assessment. 18 C.F.R. §39.4(d). Such filing "shall include supporting materials explaining the proposed collection in sufficient detail to justify the requested funding, including any departure from the approved funding formula or method," and is to be approved, disapproved, remanded or modified by the Commission.

The circumstances specified in §39.4(d), which goes unmentioned in the OE Brief, are the only circumstances in which the Commission has specified that a filing with and approval by the Commission is required in order for NERC to deviate from the spending proposed in its annual business plan and budget. Further, OE has no real answer to NERC's point that having to get separate Commission approval, between budget filings, to spend funds to respond to new needs that arise between budget filings (other than as specified in §39.4(d)) would be unworkable. OE's position also ignores the fact that NERC **annually** must file a new business plan and budget, with detailed descriptions and justifications of its proposed programs and activities and the expenditures within each program, for Commission approval. Thus, NERC could not get very far down the road of spending funds on a new, unbudgeted activity before it must make the next annual business plan and budget filing with the Commission explaining and justifying the expenditures on the activity. Moreover, if the new activity required spending at a level that could not be supported by NERC's approved ERO assessment for the year and

available reserves, a filing with the Commission would be required pursuant to §39.4(d).[22]

Aside from the disagreement over the need to file for and obtain Commission approval before NERC may spend funds on "significant unbudgeted discretionary projects," NERC's new Working Capital and Operating Reserves Policy addresses Audit Staff's concerns underlying Recommendation 2, under either formulation of its text.[23] The Policy specifies:

- Funds may be drawn from Working Capital Reserves only to the extent necessary to satisfy daily cash flow requirements, and only on the authority of NERC's Chief Financial and Administrative Officer, and shall be promptly replenished to the extent possible from future excess cash flows.
- Funds may be expended from the known contingencies Operating Reserve account only up to the amounts specified in the approved budget for each known contingency, and only on the authority of NERC's President and Chief Executive Officer ("CEO").
- Budgeted expenditures of funds in the System Operator Certification Program Operating Reserve account may be made up to the amount specified in the approved budget, and only on the authority of NERC's President and CEO.
- Expenditures of funds in the unforeseen contingencies Operating Reserve account, and unbudgeted expenditures of funds from the System Operator Certification Program Operating Reserve account, may be made only pursuant to the following approvals:
  - Up to $250,000, only on authority of the NERC President and CEO.
  - Greater than $250,000 but less than $500,000, only with approval of the Finance and Audit Committee of the NERC Board.
  - Greater than $500,000, only with approval of the NERC Board after notice to and recommendation by the FAC.

Further, under the Policy, any expenditure of funds in excess of NERC's approved budget, inclusive of budgeted Working Capital and Operating Reserves, requires prior approval of NERC's Board, after notice to and recommendation of the FAC. Additionally, the Policy

[22] NERC reiterates that the Audit Report found no instance in which NERC intentionally spent less on a budgeted activity than the amount specified in its approved business plan and budget, in order to redirect those budgeted funds to a new, unbudgeted activity. In the example cited in the Audit Report and the OE Brief - expenditures on NERC's two office relocations and its data center relocation during 2011- the activity was included in the 2011 Business Plan and Budget and the expenditures above the 2011 budgeted amount were made from available Working Capital Reserves, not by diverting funds from other budgeted activities to the office relocations. *See* NERC Initial Brief at 24-25; OE Brief at 21 (recognizing that the 2011 expenditures on the office relocations in excess of the specific budgeted amounts came from available Working Capital Reserves).

[23] OE indicates it is aware that the new Working Capital and Operating Reserves Policy will govern any "redirection" of budgeted funds to unbudgeted activities. OE Brief at 32.

mandates that any addition of full-time equivalent employees ("FTEs") or headcount, regardless of the source and availability of funding, which are in excess of the total FTEs or total headcount set forth in the approved business plan and budget for the year, requires approval of the NERC Board after review by the FAC and the Board Corporate Governance and Human Resources Committee. Thus, personnel additions beyond the total staffing levels specified in the approved budget require specific Board approval following review by the Board committees responsible for both budgeting and finance and human resources and staffing.[24]

Importantly, the Policy specifies that budgeted funds may be "redirected" to unbudgeted activities only pursuant to the authorization required (as detailed above) to expend funds from the unforeseen contingencies Operating Reserve account:

> During the course of the year, events may unfold such that some approved budget areas may run below budget, making funds available to satisfy other resource needs based on changing priorities. In the event such under runs occur, these excess funds shall be added to the unforeseen contingency operating reserve and the president and chief executive officer shall have the authority to expend such funds, and management shall also be responsible for reporting such expenditures, in the same manner as the expenditure of funds for other unforeseen contingencies set forth above.

While NERC did not have (contrary to OE's characterization) "unlimited discretion to redirect budgeted funds to other activities" (OE Brief at 33) *before* the audit, NERC certainly will not have any such discretion prospectively under the new Working Capital and Operating Reserves Policy. Similarly, while OE says the Audit Report found NERC had no clear approved policies governing how "redirected" funds may be spent and which expenditures warranted informing the NERC Board and stakeholders in advance (OE Brief at 27), the Working Capital and Operating Reserves Policy addresses this concern.

[24] Personnel Expenses typically comprise approximately 60% of NERC's budget, and personnel additions usually also necessitate some increased expenditures in other budget accounts such as Travel, Meetings, Office Rent, Office Costs, and Capital Expenditures for Computers & Software, Furniture & Fixtures, and Equipment. Personnel Expenses plus the related, personnel-driven costs together comprise about 77% of NERC's budget. *See* NERC Initial Brief at 33-34; OE Brief at 44 (noting that employee compensation is 61.4% of NERC's 2012 budget).

Under the Working Capital and Operating Reserves Policy, as described above, expenditures from the unforeseen contingencies Operating Reserve account (which will be the only means of "redirecting" funds to new, unbudgeted activities) of between $250,000 and $500,000 will require prior approval of the NERC Board FAC, and expenditures in excess of $500,000 will require approval of the full NERC Board. Requests to increase total FTE staffing or headcount above the numbers specified in the approved budget will also require Board approval. Any such requests will have to be presented at a regular or special meeting of the FAC or the Board (as applicable), which means that the request will be detailed, with supporting information, in a meeting agenda posted on the NERC Website in advance of the meeting, and the action taken on the request by the FAC or the Board will be memorialized in meeting minutes that will also be posted on the NERC Website. Therefore, stakeholders and Commission representatives will have advance notice of any such requests to the FAC or the Board for approval of significant expenditures from the unforeseen contingencies Operating Reserve account or to add FTE staff or headcount above the levels specified in the approved budget.

OE contends that the provision in NERC's version of Recommendation 2 by which NERC commits to make continued improvements in transparency concerning its budgets and "redirected" funds is too vague to be meaningful. OE Brief at 32-33. However, NERC's Working Capital and Operating Reserves Policy is detailed and specific; and NERC will have to make a compliance filing or filings in this proceeding, on a schedule set by the Commission, in which NERC will have to detail the specific steps it is taking to implement Recommendation 2. Stakeholders and the Commissions will have the opportunity to review NERC's specific proposed actions in the context of the compliance filing(s).

Finally, it has been NERC's practice, and the new Working Capital and Operating Reserves Policy requires, that "[a]ll expenditures of contingency funds . . . shall be separately reported in the budget variance reports prepared by management and included in the quarterly

Finance and Audit Committee agenda materials, which are posted on [NERC's] website."[25] OE Staff apparently believes that a procedure by which budget variances and expenditures of funds from contingency reserves are reported in quarterly variance reports is inadequate because it does not entail Commission pre-approval. However, such disclosure procedures are the hallmark of a wide range of compliance regimes, from the securities laws to state and federal campaign finance laws and many others. NERC's quarterly, publicly-posted variance reports give both stakeholders and Commission staff a window into NERC's expenditures and the extent, if any, to which they deviate from the approved budget.

Recommendation 3. Audit Report Recommendation 3 is that NERC should "[r]equest budgetary funds for activities initiated between budget cycles that were not included in the annual budget filing in a manner similar to section 1108 of the NERC Rules of Procedure (ROP)." NERC deleted this recommendation, because (1) 18 C.F.R. §39.4(d) (which ROP §1108 is intended to implement) already specifies the circumstances under which NERC must request Commission approval for expenditures not specified in the approved annual budget, and (2) requiring NERC to request approval to spend funds on any activities that were not included in the annual budget (which is what Recommendation 3 would literally require) would be unworkable and prevent NERC from addressing emerging reliability issues in a timely manner. NERC Initial Brief at 31-32. In its Response Brief, OE does not attempt to modify Recommendation 3 to something that would be arguably workable, but rather states that deletion of this recommendation is acceptable on condition that the Audit Report version of Recommendation 2 is adopted. OE Brief at 33. NERC does not accept the Audit Report version of Recommendation 2; therefore, NERC does not accept OE's condition regarding deletion of Recommendation 3.

[25] As explained immediately above, there will be advance notice, in the form of posted FAC or Board meeting agendas, of requests for approval of expenditures in excess of $250,000 from the unforeseen contingencies Operating Reserve account.

In its discussion of Recommendations 2 and 3, OE essentially concedes that NERC could not plausibly be required to request Commission approval to expend funds on any "activities initiated between budgetary cycles that were not included in the annual budget filing" and still do its job as the ERO. Instead, OE contends in its Brief that Commission approval should only be required for "significant [undefined] redirections of funds." OE Brief at 33. As noted, Audit Report Recommendation 3 is unworkable and untenable as written, and OE has not provided any modification to Recommendation 3 to attempt to make it workable (including providing any parameters for "significant redirections").

Although OE states that it would accept the deletion of Recommendation 3 if Audit report Recommendation 2 is adopted, OE also states that "Recommendation 3 is unnecessary *if* Recommendation 2 provides for Commission review and approval of guidelines that govern significant redirection of funds and delineate the activities and budget variances that do not require prior review or approval." OE Brief at 33 (emphasis in original). While NERC does not agree with the specific wording of Audit Report Recommendation 2, NERC believes that its new Working Capital and Operating Reserves Policy will satisfy the requirements listed by OE in the immediately preceding sentence. More generally, NERC agrees with OE that Recommendation 2 encompasses the concerns underlying Recommendation 3 and that Recommendation 3 is unnecessary if an appropriate version of Recommendation 2 is adopted. For the reasons given in the discussion of Recommendation 2 above, NERC's version of Recommendation 2 is appropriate, and is sufficient to warrant elimination of Recommendation 3.

B. Time Reporting and Accounting System

The section of the Audit Report on "Time Reporting and Accounting System" presented seven recommendations, nos. 9 through 15. In addition, as noted above, Recommendation 4 is appropriately discussed under this topic. Recommendations 10, 11, 14 and 15 are agreed. Recommendations 4, 9, 12 and 13 remain disputed. The fundamental issues underlying the

disputed recommendations are (1) whether NERC should be required to immediately adopt "project-specific" time reporting, expense reporting, accounting and budgeting systems, (2) what Audit Staff and OE even mean by "project-specific" cost reporting, accounting and budgeting systems, and (3) why it is so important that NERC be mandated to adopt "project-specific" cost reporting, accounting and budgeting systems. The answer to the first question is no. The answer to the questions 2 and 3 is that one cannot tell from reading the Audit Report and the OE Brief.

Recommendation 4. Audit Report Recommendation 4 is that NERC should:

> Increase the granularity of the NERC budget filings by: (1) breaking out significant cost categories in its expenses; (2) identifying proposed budgeted expenditures, at a minimum, on a project specific basis; and (3) separating working capital reserves needed for operations from working capital reserves needed for contingencies and identifying those contingencies.

NERC's proposed version of Recommendation 4 is:

> Increase the granularity of NERC budget filings by: (1) breaking out budgeted expenses, such as budgeted contractors and consultant expenditures, into more detailed cost categories; and (2) separating working capital reserves needed for operations from working capital reserves needed for contingencies to the extent they are known during business planning. (NERC Initial Brief at 28.)

NERC's version of item (1) in this recommendation preserves the Recommendation's key concept that budgeted expenses should be broken out into more detailed cost categories, while providing an example of a major cost category – budgeted contractors and consultant expenditures – for which NERC admittedly has not provided significant detail in previous years' budgets, but will in the future.[26] NERC deleted item (2) from the Audit Report recommendation because a requirement to budget all expenditures on a "project specific basis" is undefined, but would likely be costly and administratively cumbersome for NERC to implement, and would not contribute to the reliability of the bulk power system. Item (2) in the Audit Report's recommendation would require NERC to adopt "project-specific" budgeting and accounting

[26] In fact, in its 2013 Business Plan and Budget filed in Docket No. RR12-13-000, NERC has provided considerably more granularity and detail about the budgeted Consultants & Contracts expenses than it has provided in previous years' budgets.

before a determination has been made that it will provide sufficient additional useful information to management to justify the costs. Item (2) in the NERC version of this recommendation is similar to item (3) in the Audit Report Recommendation, and, NERC submits, both versions are fully addressed by NERC's new Working Capital and Operating Reserves Policy, as described above in the discussion of Recommendation 1.

Although OE states that "NERC's proposed changes are not acceptable" (OE Brief, App. A, at 1), OE primarily takes issue with NERC's deletion of the requirement that NERC must budget its expenditures on a "project-specific basis."[27] (OE Brief at 33-34.) Despite the concern expressed in NERC's Initial Brief over the undefined nature of the Audit Report's phrase "at a minimum, on a project specific basis," OE has not provided any clarity in its Response Brief as to what is intended by "at a minimum, on a project specific basis." Instead, OE offers only the unsubstantiated, conclusory assertion that Staff examined NERC's time recording and expense tracking systems "and believes that NERC would only need to make minor modifications to track time and expenses for individual projects." (OE Brief at 33.) While any "examination" Audit Staff made of NERC's time recording and expense tracking systems during the audit was necessarily cursory, the NERC Finance and Accounting personnel who work with these systems on a daily basis emphatically disagree that all that would be needed would be "minor modifications" to NERC's accounting software. NERC's current accounting system was not designed to track costs on a "project" level and could not be used to do so without significant additional administrative effort and associated costs. (*See* additional discussion under

[27] OE also objects to NERC's purported "deletion" of the requirement in item (1) of the recommendation that NERC "break out significant cost categories in its expenses." (OE Brief at 33.) However, NERC already breaks out its budgeted expenses into significant cost categories, both as to program area (such as Reliability Standards, Compliance Operations, Compliance Enforcement, and Critical Infrastructure) and type of expenditure (*e.g.*, Salary expense, Benefits expense, Retirement expense, Travel expense, Meetings expense, Conference Call expense and Office Rent). The language in NERC's version of this recommendation that it "break[ ] out budgeted expenses . . . into *more detailed* cost categories" (emphasis added) will actually require **greater** granularity in the budget presentation than would the Audit Report's version of item (1) of this recommendation.

Recommendation 13, below).

Further, OE has completely overlooked the bigger problem with its proposed requirement for accounting and budgeting on a "project specific" basis. Audit Report Recommendation 4 does not simply require NERC to develop an accounting and reporting system that would enable it to easily capture all the time and expenses incurred on identifiable major projects. Rather, it would require NERC to revise its accounting, time recording and expense tracking systems to be systems in which all of NERC's activities must be defined as specific "projects" so that every expenditure of employee time and other expenses can be linked to a unique, defined "project;" as opposed to major activities, which is what NERC is proposing as an initial step to gain further experience and provide a basis for a cost-benefit analysis of adopting more detailed project-level time and expense accounting. While some companies structure their accounting, budgeting and financial reporting on the basis of "projects," it is a fundamentally different accounting system from the one NERC has in place (and the Commission has approved[28]). Thus, a requirement to budget and record all expenditures on a "project-specific" basis could require significant modifications to NERC's accounting system.

OE states that NERC has suggested that "more granular project tracking and budgeting would not provide useful information to its management." OE Brief at 34. NERC has not made such a suggestion. To the contrary, NERC stated in its Initial Brief that, although it disagreed with the text of Audit Report Recommendation 4, "NERC does, however, agree that its budgeted expenditures can be presented in more detailed cost categories than is currently the case."[29] What NERC **has** stated, with respect to OE's insistence on "project specific" budgeting and

[28] *Order Conditionally Accepting Compliance Filing*, 123 FERC ¶ 61,282 (2008).

[29] NERC Initial Brief at 33. NERC went on to describe ways in which it would be providing increased granularity in its budgets. *Id* at 33-34. And in fact, OE later acknowledges that "NERC concurs with staff's view that increased granularity of time and expense accounting would improve transparency and accountability and enhance the Commission's ability to carry out its oversight responsibilities." OE Brief at 42.

accounting, is that:

> NERC does not believe, at this time, that for an organization its size, and given the benefits NERC anticipates from utilizing the additional functionality of its recently-installed time accounting system as further described herein, that the costs and administrative complexities of implementing and maintaining this level of "project" time accounting would be justified by the additional benefits it would provide. (NERC Initial Brief at 40-41.)

OE provides no response to this concern. Nor (to get to the crux of the issue over the different formulations of item (1) in Recommendation 4) has OE explained, in either the Audit Report or its Response Brief, *why* it is important for NERC to adopt "project-specific" budgeting and accounting at this time, rather than waiting until after NERC has implemented additional granularity in its time reporting and budgeting to determine whether "project-specific" accounting and budgeting is cost beneficial. NERC agrees that more granular detail in its budgets than provided in previous years is appropriate, and this is what NERC's version of item (1) in Recommendation 4 would require – without prescribing adoption of a particular model of accounting and budgeting.

OE does not identify any specific concerns with item (2) in NERC's version of Recommendation 4 (which corresponds to item (3) in the Audit Report recommendation). In any event, as noted, NERC's new Working Capital and Operating Reserves Policy fully addresses either version. NERC's version of Recommendation 4 should be adopted.

Recommendation 9. OE's proposed version of Recommendation 9, which is a slight modification of this recommendation from the Audit Report, is:

> Continue to implement a time reporting system with the functionality to track employees' time based on the amount of time spent on specific projects or activities and on statutory or non-statutory reliability activities.[30]

NERC's proposed version of Recommendation 9 is:

[30] The slight modification to this recommendation is the addition of "Continue to" at the start of this recommendation, to recognize that NERC has recently purchased and installed a new time reporting system that will enable time to be recorded in more detailed categories than under the predecessor system. OE Brief at 44 note 131 and at Appendix 1, page 2, note 2.

> Continue implementation of a time reporting system with the functionality to track employees' time based on the amount of time spent on functional activities or key specific projects. (NERC Initial Brief at 42.)

The difference between the two versions is the phrase "amount of time spent on *specific projects or activities and on statutory or non-statutory reliability activities*" (OE version) versus the phrase "amount of time spent on *functional activities or key specific projects*" (NERC version).

OE's Brief provides no specific justification for its version of Recommendation 9 (or its versions of disputed Recommendations 12 and 13), but only states that NERC "has provided no credible support for . . . substantively modifying Recommendation 9", and offers the general proposition that "Improving transparency through project specific tracking of employee time and expenses will provide numerous benefits, including enhanced Commission oversight." OE Brief at 44. Once again, as with Recommendation 4, OE provides no reasons why the Commission should mandate that NERC adopt a time recording and expense tracking system that requires all NERC activities to be defined as specific "projects" and requires all time and expenses to be associated with a specific "project."

As described in the Audit Report and in NERC's Initial Brief, NERC has in fact recently procured and implemented a new employee time-tracking system with greater functionality than the predecessor system to provide for more detailed time reporting by employees. Audit Report at 36; NERC Initial Brief at 40. Under its version of Recommendation 9, NERC is proposing a gradual approach to increasing the granularity of time reporting, with evaluation of the costs and benefits at each step, rather than a mandated, comprehensive switch to a project-based accounting and time-keeping system with an unknown cost-benefit trade-off. Implementation of a time-recording system that provides for time to be recorded on the basis of "functional activities," as stated in NERC's version of Recommendation 9, will enable time to be recorded and tracked by major corporate and departmental activities, as well as the program or department the employee spends the time supporting, including cross-department support activities (*e.g.*,

support provided by Critical Infrastructure Department ("CID") staff to Compliance Program audits of compliance with Critical Infrastructure Protection standards, or support provided by Compliance Program or CID staff to Reliability Standards Program standards development projects). Similarly, implementation of a time-recording system that provides for time to be recorded on the basis of "key specific projects," as stated in NERC's version of the recommendation, will enable time to be recorded to significant projects (which are the projects most likely to involve more than one program or department), without requiring a comprehensive revamping of NERC's accounting and time and expense recording processes to identify every NERC activity as a unique "project."

To implement this recommendation, NERC is developing a list of activity codes to be used for purposes of recording employee time. The list under development currently provides for a total of approximately 95 activity codes against which employee time could be recorded. For all cross-organizational support work, time would be charged to the appropriate departmental activity code under the department that has lead accountability for the activity (regardless of the employee's "home" program or department). Implementation of these time-tracking codes would represent a significant increase in the level of detail and granularity at which NERC employees record their time; however, the codes can be implemented at this level of detail relatively simply and without significant incremental cost in terms of set-up, employee training and system maintenance. At the same time, implementation of these activity codes would represent a "first step" of increased granularity, which NERC will evaluate after a reasonable period of use to assess whether additional granularity (*i.e.*, adoption of even more detailed activity codes) would be cost-beneficial in terms of the incremental information provided to management. NERC is planning to implement these more detailed activity codes in January 2013, with training of employees on use of the new activity codes taking place in the fourth quarter of 2012. In addition to monthly and quarterly reviews of this information by

management, after NERC has 6 to 9 months of data, NERC will conduct a more comprehensive review of the use of these codes and assess at that time whether implementation of additional, even more detailed codes would be sufficiently beneficial in terms of management information to justify the additional costs of implementation and maintenance. NERC proposes to file the results of that assessment as a compliance filing with respect to this audit recommendation.

NERC's version of Recommendation 9, and its planned implementation steps as described immediately above, would fully address the concerns expressed in the Audit Report that are the basis for Recommendation 9. The OE Brief describes those concerns as follows:

> [Audit] Staff expressed concerns with NERC's pre-2012 policy of tracking most employees' time for attendance purposes only and recording that time under employees' administratively-assigned operating division instead of tracking actual time spent on specific projects. [Footnote: Audit Report at 35.] The Audit Report noted that this practice was particularly problematic because NERC's operating divisions had shifted over time and NERC evolved into a "matrix" organization structure in which projects often spanned operating divisions. [Footnote: *Id.*] . . . NERC was actually only tracking employee time by the operating division in which a staff member was employed. (OE Brief at 38; emphasis added.)

Under NERC's version of Recommendation 9, and its planned implementation as described above, employee time will be tracked in *considerably* more detail than under the practice that concerned Audit Staff of "tracking most employees' time for attendance purposes only and recording that time under employees' administratively-assigned operating division." Employees will be required to record their time to an activity code that relates the subject matter of the activity (which is not necessarily led by the employee's home department). Thus, all employees working on a common activity (*e.g.*, standards development or Regional Entity compliance program oversight) will record their time for that activity against the same activity code regardless of the department in which the employee is based. Reports can then be run showing the total time devoted to that activity, total time by person and total time by department. Thus, the time-tracking system will recognize and require the recording of time spent on cross-departmental and cross-functional activities. The Audit Report's concerns that NERC's previous

time-recording procedures were not appropriate for the evolving "matrix" nature of the organization will be fully addressed.[31]

Finally, NERC's version of Recommendation 9 deletes the reference to recording time based on "statutory or non-statutory reliability activities," because NERC does not engage in non-statutory activities and does not anticipate doing so.[32] There are no non-statutory activities to develop codes for. NERC acknowledges that it could add an activity code for "non-statutory activities" to the list of activity codes it is developing, but that activity code would not need to be used. While NERC has no plans at present to engage in non-statutory activities, if NERC ever chooses to engage in a non-statutory activity, additional codes can be added to track the time spent on those activities, in addition to NERC putting in place other accounting controls to ensure the proper allocation of costs associated with those activities.

For these reasons, NERC's version of Recommendation 9 should be adopted.

Recommendation 12. NERC proposes deletion of Audit Report Recommendation 12, which states: "Develop project and business and activity codes to allow better project management, including tracking of operating expenses to project-specific levels." Recommendations 4, 9 and 13 adequately cover the subject matter of recording and reporting employee time and expenses in greater detail and with greater granularity, including with more detailed activity codes or (as urged by OE) on a "project specific basis." Recommendation 12

[31] NERC believes that OE and the Audit Report overstate the extent of the "matrix" nature of the NERC organization with regards to its impact on employee time recording. Most NERC employees spend the vast majority of their time working on activities of the program or department to which the employee is assigned. However, NERC recognizes that there are cross-functional and cross-departmental activities (in fact, NERC is striving to increase the amount of cross-functional support provided among various programs). Therefore, NERC agrees that cross-functional and cross-departmental support activities should be captured in the time tracking system, and is planning enhancements, as described above, that will accomplish this.

[32] If the Commission were to determine that any of NERC's current activities are non-statutory activities and required NERC to develop a separate source of funding for the activity, NERC would have to seriously consider ceasing to perform the activity. Receiving financial support from industry sources other than through the statutory assessment mechanism and other, existing sources could raise questions about NERC's independence.

adds nothing to Recommendations 4, 9 and 13. OE has provided no explanation of how Recommendation 12 differs from Recommendations 4, 9, and 13, nor has OE suggested any specific, unique implementation steps that NERC would be expected to implement to address Recommendation 12, that would not otherwise be encompassed by the implementation actions for Recommendations 4, 9 and 13. In fact, OE has not offered any specific justification for Recommendation 12. Recommendation 12 should be deleted.

Recommendation 13. Audit Report Recommendation 13 is:

> To the extent consistent with good business practices, NERC should expeditiously implement functionality in the expense reporting software to allow the tracking of expenses on a project and activity basis.

NERC proposes that Recommendation 13 be revised to state:

> Conduct a cost-benefit analysis in 2013 of implementing a more detailed project level budgeting and accounting system. (NERC Initial Brief at 43.)

While the Audit Report recommendation uses the phrase "to the extent consistent with good business practices," the NERC version states in a more straightforward manner that NERC must "conduct a cost benefit analysis in 2013." Further, for this recommendation as for others under this topic, OE has not provided any explanation of why NERC should be mandated to move ("expeditiously" or otherwise) to a system of tracking expenses on a project-specific basis.

NERC's version of Recommendation 13 ties to its version of Recommendation 9. NERC plans to implement expense reporting at a similar level of detail as it will implement for employee time, as described above in the discussion of Recommendation 9. After utilizing the more detailed time reporting and expense reporting systems for 6 to 9 months, and gaining background and information regarding the costs and benefits of implementation of project-level reporting and accounting systems, NERC will use this information to conduct a cost-benefit analysis of implementing "project level" budgeting and accounting systems compared to the continued use of its current systems. The cost-benefit analysis will analyze the value, in terms of providing useful information for management, of implementing "project level" time reporting

and accounting systems, and the related costs. NERC will report the results of the cost-benefit analysis in an informational filing with the Commission. Stakeholders will be able to see and comment on the cost-benefit analysis and the Commission will be able to specifically review the results. NERC's version of Recommendation 13, and its approach to this topic, will provide for incremental steps of increasing detail in time recording and expense reporting, with an appropriate stopping point to analyze whether introduction of further detail into NERC's time recording and expense reporting systems is justified by the costs – rather than a mandated flash cut to a "project-specific" time and expense reporting system as would be required by Audit Report Recommendation 13 (and related Audit Report Recommendations 4, 9 and 12).

OE contends that NERC can implement "project-specific" tracking of expenses simply by adding an extra column to its accounting software to hold a "project code field," which OE asserts "could be added with minimal cost." OE Brief at 43. NERC's current expense system would permit a project code to be assigned to an expense report, but not to an individual transaction, which would be required to correctly allocate expenses when multiple projects or activities are related to the expenses incurred. Further, even if the software modifications needed to overcome these problems were relatively simple, OE has greatly understated the additional resources that would be required for NERC to adopt "project-specific" cost and time reporting. As noted earlier, NERC's current accounting system was not designed to track costs on a "project-specific" basis and could not be used to do so without significant additional administrative effort and associated costs. NERC does not wish to prejudge the cost-benefit analysis it will conduct under its version of Recommendation 13, but adding an extra column in a software program is barely the start of implementing and maintaining a project-based accounting system. Other activities required for initial implementation and (probably more significantly) ongoing maintenance of such a system would include:

- Creating an initial list of "projects" (and related codes) that capture all of NERC's current activities.

- Training employees in the use of the new coding system for recording time and expenses.
- Identifying new activities when they are initiated and either associating each new activity with an existing "project," or creating a new "project" for the new activity.
- Monitoring for the completion of projects and deletion or deactivation of the "project" from the accounting code system, so that the system does not contain numerous unneeded project codes that an employee might inadvertently use to enter time or expenses.
- Maintaining four separate systems for consistency: general ledger, payroll, timekeeping and travel expense.
- Notifying NERC's employees each time a new project code is created of the existence of the new code and the activities for which time and expenses are to be recorded using the new code.
- Monitoring time and expense submissions into the system on an ongoing basis to catch errors in the coding and submission of information.

In contrast, the tentative activity codes that NERC has developed (as described above in the discussion of Recommendation 9), while they will introduce considerably more detail into NERC's budgeting and accounting system, are not expected to require the level of continuing attention to maintenance and revision that would be needed to maintain the "project-specific" time recording and expense tracking systems that OE advocates.

A fundamental problem with Audit Report Recommendations 9 and 13 is that NERC's current payroll and timekeeping system cannot calculate payroll expenses at the "project" level. NERC's staff is salaried staff, not hourly staff, and although all hours worked are tracked, employees are paid based on the allocation of an assumed 2,080 hours per year (40 hours times 52 weeks) to 24 semi-monthly pay periods, *i.e.*, 86.67 hours per pay period. The timekeeping system may show the employee has worked 100 hours on various activities during the pay period, but the current system cannot allocate the employee's payroll expense at the "project" level because the hours recorded as worked is more than the hours paid. The percentage of time worked on various activities can be calculated, but accounting staff would have to manually create the journal entry to post to the system, instead of using the payroll system to create the journal entry that is posted to the ledger. Additionally, the submission and entry of employee

time sheets necessarily lags the pay period in which the employee did the work and the related pay date.

OE argues that "Project-specific tracking would absorb appreciable amounts of staff time only if each NERC employee worked on dozens of projects each day." OE Brief at 43-44. OE evidently fails to appreciate the point NERC was making. What NERC stated in its Initial Brief was: "The Audit Report does not explain what Audit Staff means by 'project-specific basis.' Presumably this would involve breaking down NERC's activities into scores of 'projects' and requiring NERC's employees, each day, to determine which of the projects they have worked on." NERC Initial Brief at 40. Even if a NERC employee only worked on a small number of "projects" in a day (or in a longer period such as a week or a pay period, since, as in most such systems, the employee would not be expected to enter his or her time into the system on a daily basis), the employee would still have to check the project code list to verify that he or she had identified all the projects he or she had worked on and that the proper codes were used.[33] As in any accounting system, proper and complete entries at the individual level are critical or else the system will not provide the anticipated management information benefits and in fact could provide misleading information. [34]

Accordingly, NERC's version of Recommendation no. 13 should be adopted.

C. Board of Trustees Compensation and Expenses

This topic encompasses Recommendations 25-31. Recommendations 30 and 31 are agreed. Recommendations 25, 26, 27, 28 and 29 remain in dispute. OE has proposed a modification to NERC's version of Recommendation 29 but, as discussed below, it is not

[33] Many NERC employees, particularly management employees, do spend time on multiple activities during the course of a day.

[34] In a rather impressive display of sophistry, the OE Brief, after failing to define or explain what OE contemplates by "project-specific" reporting systems or the level of granularity the Audit Report contemplates, argues that NERC's concerns about the administrative burdens of such a system are "speculative" because NERC does not know what the Audit Report meant by "project-specific" accounting. OE Brief at 44.

acceptable to NERC.[35] Disputed Recommendations 25-28 involve two fundamental issues: (1) has NERC provided sufficient basis to show that its current method of compensating its Trustees is reasonable and within the range of Board discretion, and (2) should NERC be required to track, or conduct detailed studies of, the actual amounts of time its Trustees spend on NERC activities, and base its Trustee compensation on the results of such tracking and studies. The answer to the first question is yes. The answer to the second question is no.

Consideration of the Audit report's recommendations on Board compensation must start with the fact that, as the OE Brief makes clear, the Audit Report did not find NERC's Board compensation to be excessive (OE Brief at 62). Audit Staff also made it clear that it was not taking issue with the level of Board compensation.[36] Therefore, it is difficult to understand why OE and Audit Staff insist on being so prescriptive about the method by which NERC determines Trustee compensation.

Recommendation 25. NERC believes Recommendation 25 should be deleted.

As the OE Brief describes, for the years 2006 through 2010, compensation to the NERC Trustees consisted of a fixed annual payment of $30,000 to $32,000 per year and additional payments based on the numbers of meetings and calls participated in by the Trustee. OE Brief at 61. Although OE contends that under this compensation plan Trustee compensation was "linked in part to time spent on NERC activities" (*id*. at 54), that characterization is inaccurate – the previous compensation method based compensation in part on the numbers of meetings and calls attended, *not* on the amount of time spent on NERC activities. Trustees were compensated based on attendance at a meeting or conference call, regardless of its duration, and regardless of how much time they spent preparing for the meeting or engaged in other NERC activities.

[35] Disputed Recommendations 25-28 relate to Board compensation and disputed Recommendation 29 relates to Board expenses.

[36] Audit Report Appendix B at B-12.

In 2011, NERC moved to a flat annual retainer payment as the method of Trustee compensation. OE states that in doing so, NERC did not follow a 2008 Board Compensation Policy that specified the applicable Board committee was to determine Trustee compensation based on, among other factors, an "evaluat[ion of] the amount of work and level of responsibility the BOT is being asked to undertake" (OE Brief at 54-55 and 61). OE is incorrect. The Trustee compensation plan adopted in 2011 provides for different levels of compensation to each Trustee based on the numbers of committees and the particular committees each Trustee serves on (since some committees require more work), with the Chairman of the Board receiving additional compensation. *See* NERC Initial Brief at 67-68. Thus, the amount of work and level of responsibility each Trustee is being asked to undertake is taken into account.

Nonetheless, Audit Report Recommendation 25 would require NERC to "Consider returning to the performance-based method of compensating BOT members until NERC gains the necessary experience to support a change to a flat-fee compensation model." This recommendation is flawed in several respects, and should be deleted.

First, Recommendation 25 incorrectly refers to NERC's previous compensation method as "performance based." It was not "performance based." It compensated Trustees, in part, based on attendance at meetings and participation in conference calls. The compensation was not based on the quality (or lack thereof) of the Trustees' performance of their responsibilities as Board members. As described at pages 66-67 of NERC's Initial Brief, NERC has other mechanisms in place to evaluate the quality of Trustees' performance of their responsibilities.

Second, Recommendation 25 is based in large part on the Audit Report's criticisms of a consultant report that was prepared in 2010 in connection with consideration of adoption of the annual retainer compensation method, and, more generally, on what OE perceives to be a lack of evidentiary support for the decision to adopt this method at the time it was made in 2011. OE Brief at 60-63. However, consistent with the purpose of a performance audit (as stated by Audit

Staff) to identify opportunities to improve NERC's operations prospectively (*see* §II.B above), the relevant question is whether the annual retainer method is reasonable and appropriate within the range of Board discretion – not whether Audit Staff could find a satisfactory (to Audit Staff) amount of contemporaneous documentation from 2011 on the basis for this compensation method. NERC has provided numerous reasons supporting the use of the annual retainer method of compensation as reasonable and appropriate, as compared to one based on a combination of an annual fee and Trustee attendance at meetings. NERC Initial Brief at 63-68. OE fails to address these reasons head-on, other than arguing that some of them were not cited in the 2011 consultant study. In particular:

- OE does not dispute (and in fact acknowledges) that Trustee compensation based on a fixed annual retainer rather than on the number of meetings called and attended enables NERC to budget this expense item more accurately. OE Brief at 61.[37]
- OE does not dispute that a per-meeting compensation approach creates an incentive to schedule additional meetings.
- OE does not dispute (and in fact acknowledges) that the greater predictability of compensation and the tax planning advantages, from the Trustee perspective, of the fixed annual retainer method is beneficial in Trustee recruitment. OE Brief at 61-62.
- OE does not dispute that having to track the amount of time that each Trustee actually spends on NERC activities would create additional administrative burdens and costs for both NERC and its Trustees.

Despite not disputing these points, OE says that NERC did not provide any evidence that unnecessary meetings were being called, that Trustee candidates were concerned about variable compensation, or that additional administrative costs were being incurred. (OE Brief at 62.) But these are structural issues. Saying that the compensation method does not need to be designed to eliminate incentives for unnecessary meetings until unnecessary meetings have actually occurred

[37] OE asserts that Trustee compensation is no different than other NERC expenses that are "trued up annually." OE Brief at 61. NERC does not understand the point of this comment. While NERC files budget-to-actual cost "true-up" reports with the Commission annually, neither Trustee compensation nor any other expenses are "trued up" in the sense that NERC assesses a year-end additional charge (or refund) to the load-serving entities reflecting any variances from the budgeted amounts used to set the original assessments. OE's comment seems to view NERC's expenses like utility costs that are recovered from customers through an automatic adjustment charge in the utility's tariff, which is certainly not the case for NERC's expenses.

is like saying that federal officeholders and candidates should not be required to file reports of their campaign contributions and expenditures with the Federal Election Commission until they have actually violated the law.

NERC has demonstrated that its current annual retainer method of Trustee compensation is reasonable and appropriate, and certainly within the range of reasonable Board judgment. That should be all that is necessary to resolve this issue, regardless of the quality or extent of contemporaneous documentary justification for adoption of the current method in 2011 that NERC was able to produce.[38]

Third, OE contends that the move to the fixed annual retainer compensation method contravened the 2008 Board Compensation Policy, referred to above, because the move was not supported "with a time study based on actual time spent by the BOT on BOT activities or a representative study of the actual time spent on these activities." OE Brief at 56. But the 2008 Board Compensation Policy did not require that compensation be based on a "time study based on actual time spent by the BOT." Rather, it required that in developing the Trustee compensation plan, the Board's Corporate Governance and Human Resources Committee "evaluate the amount of work and level of responsibility trustees are being asked to undertake" (emphasis added). OE Brief at 54. As explained above, the current Trustee compensation plan takes into account the amount of work and level of responsibility each Trustee is being asked to undertake.

Fourth, implicit in Audit Report Recommendation 25 is a presumption that the previous method that compensated Trustees in part based on attendance at meetings was a preferred or superior method, and that NERC somehow had a burden of proof to justify switching to another

[38] OE notes that the 2010 consultant's report on Board compensation stated that less than 30% of corporate boards used annual fees. OE Brief at 56. OE fails to mention the more recent evidence (contained in the public report of a leading compensation consulting firm that was not commissioned by NERC) that only 37% of boards are paid per-meeting fees, down from 72% in 2001 and 57% in 2006, and just 35% of companies pay fees for board committee meetings. *See* NERC Initial Brief at 66.

Trustee compensation method. However, neither the Audit Report nor the OE Brief explains why the previous method warrants the benefit of such a presumption, or why the previous method is better than the current method. Without such an explanation, there is no basis for complaining that NERC failed to justify adoption of the current method rather than staying with the previous method. Again, NERC explained in its Initial Brief why the annual retainer method of compensation, coupled with its other mechanisms in place to directly evaluate Trustee performance, is superior to a compensation method based on attendance.

Fifth, Recommendation 25 would require NERC to consider returning to its previous Board compensation method, based on attendance, "until NERC gains the necessary [unspecified] experience to support a change to a flat-fee compensation method." However, no "experience" is necessary to support the use of a flat-fee compensation method.

NERC recognizes that Audit Report Recommendation 25 would only require NERC to "consider" returning to the previous compensation method. In this aspect, however, Recommendation 25 is unnecessary because it is duplicative of NERC's version of Recommendation 28, which requires NERC to continue to conduct annual reviews of the Board compensation plan, taking into account Board time and participation on Board activities. In connection with Recommendation 28, NERC has committed that (as provided in the mandate of the Corporate Governance and Human Resources Committee of the NERC Board) it will continue to evaluate the Board compensation plan annually. NERC Initial Brief at 72 and 73-74.

Recommendation 26. Audit Report Recommendation 26 is that NERC should "Establish a method for tracking BOT time and participation on BOT activities to be able to properly evaluate and quantify the performance of each trustee." NERC deleted this recommendation as unnecessary. NERC does record Trustees' attendance at meetings and

conference calls,[39] but does not see a need to track the amount of time spent by Trustees in meetings, conference calls and other NERC activities, in order to be able to "properly evaluate and quantify the performance of each trustee." As noted above and as explained in its Initial Brief (at 66-67), NERC has other mechanisms in place to evaluate Trustee performance (including mechanisms that provide for direct stakeholder input), and does not need to track the hours that each Trustee spends on NERC activities in order to be able to evaluate the quality of the Trustee's performance of his or her responsibilities. Tracking hours would only record time and would not provide a measure of the actual effectiveness of the Trustee in performing his or her responsibilities. Moreover, implementing a time-tracking system would be burdensome to the Trustees and create yet another additional administrative activity for NERC staff. Recommendation 26 should be deleted.

Recommendation 27. Audit Report Recommendation 27 is that NERC should "Implement the planned BOT tracking software to assist in measuring BOT participation and reducing undue administrative burden." NERC deleted this recommendation because, as stated in NERC's Initial Brief, there is no "planned BOT tracking software." NERC explained in its Initial Brief that Audit Staff may have been under the misimpression that NERC's recently-implemented enhanced employee time recording system would be used for Trustees. NERC Initial Brief at 73. Based on the OE Brief, NERC now understands that the Audit Report was referring to a vendor-provided electronic portal and software which NERC was considering acquiring, referred to as "Digital Books for Trustees." OE Brief at 63 note 196. NERC has now acquired and implemented this tool (the product NERC acquired is called "Diligent Boardbooks"). This secure electronic tool enables Board members to access the often voluminous Board and committee meeting materials and other materials relating to NERC

[39] The Trustees attending a Board or Board committee meeting or participating in a Board or Board committee conference call are listed in the minutes of the event.

activities without having to send them bulky paper documents or large e-mail attachments that may prove to be undeliverable due to size. The Diligent Boardbooks tool includes a calendar device Trustees can use, but does not provide time tracking or entry capability for hours spent.

In summary, NERC has no plans to expend funds to acquire software that would track Trustee time. In any event, NERC reiterates that tracking the actual number of hours that each Trustee spends in meetings, conference calls and other NERC related activities is not necessary for an evaluation of the Trustees' performance.[40] As noted, Trustee attendance at Board meetings, committee meetings and conference calls, as well as some other NERC activities, is recorded, and this is sufficient information on the extent of each Trustee's level of effort for purposes of the annual review of the Board compensation plan, along with the other information available on the Trustees' performance in carrying out their responsibilities. Recommendation 27 is unnecessary and should be deleted.

Recommendation 28. Audit Report Recommendation 28 is:

> Conduct an analysis of BOT participation and effort based on a time study using actual time spent during BOT activities, or a representative study of the actual time spent and implement a compensation methodology that pays BOT members reasonably for performance of their duties.

NERC proposes that this Recommendation be revised to the following:

> Continue to conduct annual reviews of the Board compensation plan, taking into account Board time and participation on Board activities and conduct periodic market studies regarding the structure and amount of Board compensation.

The Audit Report version of this recommendation would mandate that NERC conduct a specific study of the amount of time spent by Trustees on Board activities, and then implement a Trustee compensation method based on the results of that study. The directive in Audit Report Recommendation 28 would unequivocally be micromanagement. It would also be a much

[40] On page 65 of its Initial Brief, NERC provided examples of some of the many NERC-related activities in which the Trustees participate, in addition to attending the quarterly Board and Board committee meetings.

deeper dive into management and board decision-making prerogatives than the Commission has previously taken with respect to entities under its jurisdiction.[41] *See* NERC Initial Brief at 13-16.

As noted above, and as reflected in NERC's version of Recommendation 28, the Corporate Governance and Human Resources Committee of the NERC Board is mandated to conduct an annual review of the Board compensation plan. As reflected in NERC's version of this recommendation, the annual reviews "tak[e] into account Board time and participation on Board activities." This is a sufficient requirement that the level of effort expended by, and participation of, Trustees on NERC activities be taken into account in determining how, and how much, Trustees will be compensated – without requiring that specific studies of the amount of time spent by Trustees be conducted or that a Trustee time-tracking tool be used in determining Trustee compensation.[42] The NERC version of Recommendation 28 also specifies that periodic market studies shall be conducted regarding the structure and amount of Board compensation, for use in determining the Board compensation plan. NERC's version of this recommendation provides for annual review of Trustee compensation and specifies that Trustee participation and effort and market data on board compensation will be taken into account. The NERC version provides sufficient guidance for the determination of Board compensation without being

[41] Although OE disclaims that it is attempting to micro-manage NERC's Trustee compensation decisions, OE makes detailed, intrusive suggestions such as that NERC should have increased the fixed retainer component of the Trustees' compensation to compensate them for out-of-meeting activities (OE Brief at 61 note 187) and should have set a "minimum meeting duration" so that Trustees would not be compensated for meetings that were too short. *Id.* at 62.

[42] OE states that NERC "already must track" Trustee time because nonprofits must report to the Internal Revenue Service ("IRS"), on IRS Form 990, the trustee "average hours per week." OE Brief at 62 and 63. However, the IRS form requires the organization to provide an estimate of the average hours per week each person listed in the report devotes to the organization's activities. (*See Instructions for Form 990 Return of Organization Exempt from Income Tax*, at 26 (Instructions for Part VII, Section A, Column B) (available at: http://www.irs.gov/pub/irs-pdf/i990.pdf)). It does not require actual tracking of time. NERC fulfills this reporting requirement by using an estimate provided by each Trustee of his or her average number of hours per week devoted to NERC business during the year. NERC presumes that OE would not accept these Trustee-provided annual estimates as sufficient to satisfy the requirements of Audit Report Recommendations 26-28 for "tracking" of Trustee time and studies of the actual time spent by Trustees on NERC activities.

prescriptive or requiring a specific type of study, and should be adopted as the recommendation on this topic.[43]

Recommendation 29. In its Initial Brief, NERC proposed a modified version of Audit Report Recommendation 29, to read as follows:

> Estimate and include in its annual budgets an amount of funding to cover expenses for Trustees in connection with Board and Board committee meetings and other NERC activities that it deems appropriate and seek approval for such funding. (NERC Initial Brief at 72.)

In its Response Brief, OE indicates states that the NERC version of Recommendation 29 is acceptable to OE if the phrase "for Trustees" is deleted. OE Brief at 64. NERC understands the purpose of OE's proposed further modification to be that all expenses relating to Board and Board committee meetings, not just the costs incurred by Trustees, would be budgeted in a separate account. However, NERC does not accept this further revision. OE's further revision would require, for example, that the travel expenses of NERC management and staff to attend Board meetings would have to be separately budgeted and (when incurred) charged to the "Board meetings" account rather than to the departmental travel expenses accounts in which all other travel costs of department employees are recorded. NERC's version of Recommendation 29 will satisfy the underlying objective of capturing all expenses for Trustees incurred in connection with Board meetings, Board committee meetings and other NERC activities in which one or more Trustees participate.

D. NERC Activities

There are two recommendations in this section of the Audit Report, Recommendations 37 and 38. With respect to Recommendation 37, the disagreement is over the manner in which NERC implements the recommendation. However, as discussed immediately below, NERC proposes a modification to its plan for implementing the recommendation which NERC believes

[43] Moreover, the NERC version of Recommendation 28 is consistent with the 2008 Board Compensation Policy cited by OE. OE Brief at 54-55.

will satisfy OE's concern. With respect to Recommendation 38, NERC and OE do not agree on the text of the recommendation.

Recommendation 37. In its Initial Brief, NERC proposed a revised version of Recommendation 37, reading as follows:

> Establish written criteria for determining whether an activity is a statutory activity and should be funded under section 215 through an open and transparent process initiated by NERC. (NERC Initial Brief at 99.)

NERC also proposed the following process for implementing this recommendation:

> To implement this recommendation, NERC plans to develop the criteria through a stakeholder process that it will initiate in the fourth quarter of 2012 and complete by July 2013, in sufficient time to submit the criteria in, and use the criteria in preparing, NERC's 2014 business plan and budget filing. The Commission would then be able to review and, to the extent it deems necessary, rule on the criteria in the context of reviewing and ruling on NERC's 2014 business plan and budget, which will also take into account stakeholder input regarding the criteria and the scope of NERC's activities. (NERC Initial Brief at 100.)

OE does not state any disagreement with the text of NERC's version of Recommendation 37. However, OE states that "Staff and NERC disagree on implementation of this recommendation" (OE Brief, Appendix A at 6), that "Staff does not accept NERC's proposal to delay its filing of the new criteria and processes to be developed under Recommendation 37" (OE Brief at 78), and that the Commission should reject NERC's proposal to submit the criteria and processes for the first time in NERC's 2014 budget filing,[44] and should require NERC to submit the criteria and processes at an earlier date, in a compliance filing. *Id*. OE also states that it agrees the new criteria and processes should go into effect as part of NERC's 2014 budget. *Id*.

NERC accepts OE's position that the criteria that NERC will develop through a stakeholder process pursuant to Recommendation 37 should be filed with the Commission in a compliance filing in advance of filing the 2014 Business Plan and Budget. NERC commits to completing its process for developing the criteria and to file the criteria with the Commission, in

[44] The 2014 Business Plan and Budget filing will need to be filed at the Commission by August 23, 2013.

a compliance filing, by March 1, 2013. NERC will use the filed criteria in developing its 2014 Business Plan and Budget, with any revisions indicated by the Commission's order on the compliance filing, if that order is issued sufficiently in advance of the filing date (August 23, 2013) for the 2014 Business Plan and Budget to be taken into account in budget development. If the order is not issued in sufficient time to be taken into account in developing the 2014 Business Plan and Budget, then NERC will reflect any revisions to the criteria indicated by the Commission's order in preparing the following year's business plan and budget.

Recommendation 38. In its Initial Brief, NERC proposed a revised version of Recommendation 38, reading as follows:

> In its annual business plan and budget filings, provide an explanation as to why the proposed activities to be undertaken by each program area for the budget year are statutory, including, at a minimum: a description and the purpose of the major activities to be undertaken by each program area and an explanation for why the activity is a statutory activity. (NERC Initial Brief at 99.)

OE's only objection to NERC's proposed text of this recommendation is to NERC's proposal (as described by OE) "to explain why only 'major activities' – rather than *all* activities – are statutory." OE Brief at 78-79 (emphasis in original). NERC submits that OE is taking the term "major activities" in NERC's version out of context. The first sentence of NERC's version would require NERC to provide, in each annual business plan and budget filing, "an explanation as to why the proposed activities to be undertaken for the budget year are statutory." The reference to "major activities" in the subordinate clause recognizes that various activities in a program area can be grouped into categories and the purpose and statutory basis for each such category explained. An example of a "major activity" would be providing stakeholder education regarding standards and compliance, versus identifying and explaining the Section 215 basis for each workshop or seminar that will be held in furtherance of this activity. If providing such stakeholder education is a statutory activity, then all individual education and training sessions

and associated support activities are statutory without the need to describe each of them and their individual connections to Section 215 in the business plan and budget document.

Further, OE's concerns are unwarranted given that this recommendation is enforceable by the Commission on an ongoing basis through its review of NERC's annual business plan and budget filings. If the Commission concludes that a NERC budget filing has not provided a sufficient explanation of why a particular activity included in the business plan and budget is a statutory activity that should be funded pursuant to Section 215, the Commission can order NERC to provide more information in a compliance filing, or can direct that the activity and related costs be removed from the budget. NERC has a strong incentive to provide, in its business plan and budget filings, complete explanations of why all of its proposed activities are statutory, in order to avoid having activities removed from the budget and to avoid having to prepare and submit compliance filings.

E. Other Recommendations - Conditions Proposed by OE / Accepted by NERC

1. Employee Entertainment – Recommendations 22, 23 and 24

In its Initial Brief, NERC proposed the following revised versions of Recommendations 22, 23 and 24 (NERC Initial Brief at 60-61):

> 22. Explicitly budget for employee rewards and recognition and entertainment expenses by including line items of sufficient granularity in the budget filings.
>
> 23. Use miscellaneous expense accounts to track expenses which are for employee rewards and recognition or entertainment separately from other business-related expenses in its accounting system.
>
> 24. Ensure rewards and recognition expenses and entertainment expenses are clearly and transparently presented to the Board, the Commission, and stakeholders in the budget before these costs are incurred.

In its Response Brief, OE states: "NERC's proposed changes to Recommendations 22, 23, and 24 are acceptable on the condition that NERC develop and submit clear policies and procedures that identify the costs to be recorded as employee rewards and recognition, and develop and file policies and procedures for how NERC will provide such rewards and

recognition." OE Brief, Appendix A at 4 note 3; *see* OE Brief at 53-54. NERC accepts this condition. NERC will develop (1) policies and procedures that identify the costs to be recorded as employee rewards and recognition, and (2) policies and procedures for how NERC will provide such rewards and recognition, and will submit these policies and procedures in the compliance filing scheduled by the Commission in this proceeding.

2. NERC as the ES-ISAC – Recommendations 39, 40, 41 and 42

In its Initial Brief, NERC proposed that Audit Report Recommendations 40, 41 and 42 be deleted and that Audit Report Recommendation 39 be replaced with the following text that encompassed all four recommendations:

> Provide additional information in NERC's 2013 Business Plan and Budget regarding NERC's role as the ES-ISAC; and initiate an open and transparent process to provide opportunities for stakeholder input regarding NERC's role as the ES-ISAC, including (1) the impact, if any, on NERC's compliance-related activities of "walling off" certain staff from the ES-ISAC activities; and (2) access of FERC staff to ES-ISAC information for situational awareness and compliance purposes. (NERC Initial Brief at 105-106.)

In its Response Brief, OE states that NERC's proposed changes to Recommendation 39 and the deletion of Recommendations 40, 41 and 42 are acceptable "with the condition that a clarification of the Commission's ES-ISAC oversight responsibilities is clearly laid out as part of this process, and provided the Commission has an opportunity to expressly consider and approve or disapprove ES-ISAC's statutory funding eligibility." OE Brief, Appendix 1 at 7 note 5; *see* OE Brief at 85. NERC agrees with these conditions. With regard to the first condition, the stakeholder process that NERC will conduct pursuant to Recommendation 39 will address clarification of the Commission's ES-ISAC oversight responsibilities. With regard to the second condition, the Commission can consider and approve or disapprove the ES-ISAC's statutory funding eligibility in a future business plan and budget proceeding, or in a separate proceeding established by the Commission. Recommendation 38 (*see* §III.D, above) will require NERC to include in its annual business plan and budget filings a description of the purpose of the ES-

ISAC activity and an explanation of why it should be funded pursuant to §215.

IV. Factual Findings

In this section, NERC responds to assertions in the OE Brief concerning the factual findings in the Audit Report that have not been already addressed in NERC's Initial Brief or in the discussion of a related recommendation in §III above.

A. NERC Budget Process

Although NERC has agreed (and has developed and implemented) a detailed written procedure on the approvals required to use funds from Working Capital and Operating Reserves and to spend funds budgeted for one activity on another activity, NERC disagrees with OE's statement that NERC had limited procedures and controls concerning these matters. (OE Brief at 5, 21, 27.) NERC has in place policies specifying that expenditures of funds in excess of budgeted amounts are required to be approved by the applicable department head, the NERC Chief Financial Officer and, depending on the amount and nature of the expense, by NERC's President and CEO. Further, the availability of funds to be used for the purposes specified in such requests is evaluated in light of NERC's other funding needs.

With respect to the only instance of purportedly "redirected" funds cited in the Audit Report, the expenditures in 2011 from Working Capital Reserves in order to expeditiously complete NERC's office relocations and data center relocation, NERC agrees that it explicitly identified $1,175,000 of specific relocation-related expenditures in its 2011 Business Plan and Budget, but disagrees with OE's contention that NERC was limited to spending no more than that amount in 2011 on the office relocations. OE Brief at 21, 25, 31. NERC clearly stated in its 2011 Business Plan and Budget filing that it would use Working Capital Reserves to fund any additional expenditures on the office relocations in 2011. *See* NERC Initial Brief at 24-25. OE not only gives short shrift to this plan, which was clearly disclosed in the 2011 Business Plan and Budget filing, but also fails to respond to NERC's explanation of why it was prudent to proceed

to complete the office and data center relocations as expeditiously as possible once they were announced.[45] (*See id.* at 25-26.) However, OE does acknowledge that the Audit Report did not address the prudence of any past expenditures. OE Brief at 27. Further, the fact that NERC was relocating its offices, and specifically that the headquarters office would be moved from Princeton to Atlanta, and the reasons for those decisions, were set forth in detail in the 2011 Business Plan and Budget filing. *See* NERC Initial Brief at 24. Presumably OE is not suggesting that the Commission, having approved the relocation decision in the 2011 Business Plan and Budget, should have had the opportunity to revisit that approval in the following two budget cycles. NERC emphasizes again that the additional 2011 expenditures were funded from Working Capital Reserves that were higher than expected at year-end 2010 – not by intentionally spending less than the budgeted amounts on other programs in order to free up funds for the office relocations. NERC Initial Brief at 25.

OE states that NERC officers told Audit Staff that working capital reserves were viewed as contingency funds to be used for unexpected expenditures. OE Brief at 21 note 60. But that is exactly what the Commission stated in one of its early NERC budgeted-related orders: "Working capital reserves provide readily available funds, which are available without a charge for or restriction on their use, to meet unforeseen expenditures." *North American Electric Reliability Corp.*, 129 FERC ¶ 61,040 (2009) at P 24.

Although NERC has agreed to increase the level of detail provided in its budget filings, NERC disagrees with OE's assertion that NERC heretofore has presented only "high level" information in its business plans and budgets. OE Brief at 5. For example, NERC's 2012 Business Plan and Budget document (the last one prepared and filed prior to the audit) was 134

[45] NERC did originally intend to spread the work and related expenditures for the office and data center relocations over 2 to 3 years in order to spread out the expenditures and reduce their impact in terms of causing year-to-year fluctuations in the assessments to load-serving entities. However, after it announced the relocations, NERC realized that they needed to be carried out much more expeditiously, for the reasons explained at NERC Initial Brief at 25-26.

single-spaced pages long, not counting the tables that showed the allocation of the 2012 ERO funding requirement to the Regions and the calculation of assessments to individual load-serving entities. A detailed statement of revenues, operating expenses and capital expenditures was provided for the entire company and for each of the five statutory programs and five administrative departments. These statements showed the budgeted 2012 operating expenses and capital assets expenditures broken out into numerous categories, including Salaries, Payroll Taxes, Benefits, Retirement costs, Meetings expense, Travel expense, Conference Call expense, Consultants & Contracts expense, Office Rent, Office Costs, Furniture and Fixtures capital expenditures, Computer Equipment and Software capital expenditures, Depreciation, and more. The statements also showed the 2011 budgeted amount and projected amount for each line item and the change to the 2012 budgeted amount. The Business Plan and Budget document contained, for each statutory program and administrative department, a description of its activities, a discussion of its principal goals and deliverables/objectives for 2012, and a discussion of the reasons for cost increases or decreases from the 2011 budget for those line items for which significant changes were budgeted. Separately, in Section B of the Business Plan and Budget, detailed tables were included showing detailed budgeted expense changes in each of numerous expense categories, including Personnel Expenses (Salary, Payroll Taxes, Benefits and Retirement costs); Meetings, Travel and Conference Call expenses; Consultants & Contracts expense; Office Rent; and Office Costs, with explanations provided for significant changes from the 2011 budget. Finally, 19 pages of detailed business planning and budgeting assumptions were provided.

Similarly unsupportable is OE's assertion that NERC's annual true-up reports to the Commission have provided only high level information and were not at the same level of granularity as the budgets. OE Brief at 5, 22. The format of the true-up reports has included statements of revenues, expenses and capital asset activity at the same level of detail as those

statements provided in the budget, *i.e.*, for the entire company and for each of the statutory programs and administrative departments, with each statement in the true-up report showing the same line items as in the budget. The true-up report has shown the budgeted amount, actual amount, and variance for each line item. NERC has applied a threshold for providing narrative explanations of the line item variances on the individual statements – generally for variances greater than the larger of 10% of the budgeted amount or $10,000 – and the Commission's orders accepting the true-up filings have not indicated that this variance threshold for providing narrative explanations should be lowered.

NERC has provided the level of detail and information in its business plan and budget filings and in its annual true-up reports that was indicated by the Commission's previous budget-related orders and guidance received from the Commission staff who review NERC's budget filings. NERC does not dispute that it is appropriate for Audit Staff to make recommendations for improvements going forward (in this case, to provide more detail in future business plan and budget filings), but to find that the amount and detail of information NERC provided in its annual business plan and budget filings and true-ups violated any Commission requirements, or were deficient, is unsupportable. The Audit Report's proposed findings under NERC Budget Process should be rejected by the Commission.

B. NERC Oversight of the Regional Entities' Budgets

NERC has agreed to the recommendations in this section of the Audit Report (Recommendations 6, 7, 8), relating to NERC's oversight of the preparation of the Regional Entities' business plans and budgets, and NERC has already implemented actions in response to these recommendations in connection with preparation of the 2013 Regional Entity business plans and budgets, including providing for more substantive reviews and input from NERC program and department heads. However, NERC does not agree with OE's assertion that NERC should have used the budget preparation process to evaluate the composition of the Regional

Entities' CIP audit teams and the skills of audit team members. OE Brief at 35. While ensuring that the Regional Entities perform satisfactory CIP compliance audits is an appropriate activity, NERC does not believe that the review of the composition and skills of the Regional Entity CIP compliance audit teams is an activity that should necessarily be carried out as part of the budget preparation process.

C. Time Reporting and Accounting System

OE states that Audit Staff found "evidence of NERC first-line managers' positive reactions to [sic] when staff suggested increased timekeeping granularity." OE Brief at 42. As previously stated, NERC has installed a new time accounting system and its management team has worked to develop a set of activity codes that will provide additional granularity for use by management and others. Resources are not unlimited, and management and stakeholders (and the Commission) must focus on whether the costs of such enhancements are justified by the benefits they provide. It is doubtful that Audit Staff and NERC's first-line managers discussed the costs as well as the benefits of a "project-level" time accounting system in any detail or with sufficient information to support the conclusion that OE suggests with respect to the implementation of "project-level" time accounting.

D. Employee Compensation

NERC has agreed to all three of the Audit Report's recommendations on this topic (Recommendations 16, 17, 18). The OE Brief contains no new arguments regarding the Audit Report's findings that were not addressed in NERC's Initial Brief. With respect to the Audit Report's criticisms of the Mercer compensation studies, NERC notes that the OE Brief states that "NERC's explanation of the Mercer studies' assumptions, coupled with [NERC's] acceptance of the Audit Report's three recommendations, address staff's concerns." OE Brief at 48.

E. Standard for Determining the Reasonableness of Expenses

NERC has agreed to all three of the Audit Report's recommendations on this topic

(Recommendations 19, 20, 21). The OE Brief contains no new arguments regarding the Audit Report's findings that were not addressed in NERC's Initial Brief. However, NERC does not agree with OE's characterization that expenditures for employee rewards and recognition are not "routine business expenses." OE Brief at 48-49. All manner of businesses and organizations incur expenses to reward or recognize employees for excellent performance or efforts beyond what is normally required, or to boost employee morale or for team-building purposes. These expenditures are considered ordinary and appropriate costs of operating the business. These comments are also relevant to the topic of Entertainment Expenses, below.[46]

F. Employee Entertainment

NERC and OE have reached agreement on the three recommendations on this topic (Recommendations 22, 23, 24), including OE's conditions to acceptance of NERC's versions of these recommendations. *See* §III.E.1 above. The OE Brief contains no new arguments regarding the Audit Report's findings that were not addressed in NERC's Initial Brief. However, see the comments concerning the accounting for employee rewards and recognition expenses under Standard for Determining the Reasonableness of Expenses, above.

G. Board of Trustees Compensation and Expenses

All of the arguments in the Audit Report and the OE Brief concerning the Audit Findings on this topic have been addressed in either or both of NERC's Initial Brief or the discussion of the recommendations on this topic in §III.C above. Although NERC is agreeing to take various actions based on the recommendations, there is no basis for any audit findings that NERC's performance was deficient with regards to Board compensation or expenses.

[46] Additionally, the suggestion that it is improper to record the employee expenses as "routine business expenses" was not made in the Audit Report and is raised for the first time in the OE Brief. Neither the proposed Audit Finding nor the three recommendations on this topic address the accounting for employee expenses.

H. Retirement Plans

NERC and OE have reached agreement on the three recommendations on this topic (Recommendations 32, 33 and 34). However, NERC takes exception to OE's characterization that NERC, in its Initial Brief, attempted to justify its retirement plan provisions by "describing their evolution." OE Brief at 66. OE misses the point of the discussion referred to, at pages 76-77 of NERC's Initial Brief, which was to show that NERC's retirement plan provisions were adopted in an effort to remain competitive with companies and organizations with which NERC competes for employees, including for-profit companies that can offer compensation plan provisions (such as stock options and performance share grants) that NERC cannot offer. NERC therefore decided to offer other compensation and benefit provisions (such as the additional 10% 401(k) contribution) in order to provide a competitive overall compensation and benefits package. Similarly, OE's statement that NERC's retirement plan package was higher than industry average and did not reflect market conditions (OE Brief at 67) reflects an evaluation of an individual component of total remuneration out of context and fails to recognize that NERC competed for employees with for-profit companies that could offer compensation and benefits components that NERC cannot or did not offer.

Finally, OE notes that the Audit Report did not rely on any NERC violations of IRS requirements concerning its retirement plans to reach the Audit Findings on this topic. OE Brief at 67. However, the absence of any violations of IRS requirements should have been relevant to Audit Staff's analysis, because the provisions of 401(k) and other retirement plans are largely driven by the requirements and limitations of the Internal Revenue Code and IRS regulations.

I. NERC Critical Infrastructure Protection Program

NERC and OE are in agreement on the two recommendations under this topic (Recommendations 35 and 36). However, NERC takes issue with a number of assertions in the OE Brief.

First, the number of Regional Entity CIP compliance audits on which the Commission chooses to expend its resources by sending observers (OE Brief at 68) is not a valid or reasonable guide to the number of CIP audits to which NERC should send observers in order to exercise appropriate oversight over the Regional Entities' CIP auditing activities. The NERC CIP Auditors who provide Regional oversight maintain an audit attendance selection process based on location, Regional Entity and available resources. Each calendar year, the NERC Critical Infrastructure Department ("CID") assesses U.S. and Canadian registered entities scheduled for a CIP standards compliance audit using the master audit schedule maintained by the NERC Compliance Operations department. In determining which CIP compliance audits to attend, CID applies the criteria listed at page 85 of NERC's Initial Brief.

Second, attending Regional Entity CIP compliance audits of registered entities is one of many available methods to assess the Regional Entity's performance under the Compliance Monitoring and Enforcement Program. Additional oversight activities may include engagements at the Regional Entities' offices to review processes, tools and process actions. Key Reliability Spot Checks is another method that is used to assess Regional Entity performance. Review of Regional Entity processing and transition of compliance issues from auditing or field staff to the enforcement staff, and review of mitigation plans and enforcement actions, are also oversight activities with respect to the Regional Entities' CIP compliance programs.

Third, OE asserts that by not attending the CIP compliance audits that were attended by Commission representatives, NERC "shifted primary responsibility for overseeing [Regional Entity] CIP compliance audits to FERC." OE Brief at 68. There is no support for this assertion, and NERC disagrees with the implication that every CIP audit conducted by a Regional Entity needs an "overseer." The Regional Entities are, in fact, primarily responsible for carrying out the CIP audit program (as well as the audit program for the operations and planning standards). However, as explained in NERC's Initial Brief, NERC has sought to provide guidance and

oversight to the Regional Entities in their conduct of their CIP compliance audit programs, through such activities as development and refinement of the Reliability Standards Audit Worksheets ("RSAWs") for the CIP Standards, CIP auditor training workshops and seminars, development and issuance of Compliance Application Notices ("CANs") which provide guidance on application of the CIP standards to auditors as well as to industry, and review of the Regional Entities' CIP audit reports. *See* NERC Initial Brief at 82-83. In fact, OE acknowledges that attending the Regional Entities' CIP audits is not the only way to provide oversight to their CIP programs, and disclaims any intention to convey such an impression. OE Brief at 71.

Further, as is well known, compliance auditors are trained to review documentary evidence of compliance, in preference to oral "testimony" from personnel of the registered entity. (Much like Audit Staff here, we note.) Compliance audits are typically scheduled for the registered entity's location where there are a large number of standards requirements scheduled to be audited. Registered entities are generally requested and expected to submit their documentary evidence to the audit team in advance. The documents can be reviewed by NERC staff, as needed, either before or after the actual on-site audit. In short, it is not necessary for NERC personnel to be physically in attendance at the registered entity's location during a compliance audit in order to provide oversight of the audit.

OE states that "Whether [Regional Entity] staff adequately perform their CIP compliance activities is a different question outside this audit's scope." OE Brief at 71. But with no evidence that the Regional Entities are failing to adequately carry out their CIP compliance auditing responsibilities, there is no basis for a finding that NERC's oversight activities were inadequate. OE also asserts that "More active NERC oversight [read: attendance at audits] could have provided additional technical guidance to improve both [Regional Entity] team performance and the performance of audited registered entities" and could have "ensur[ed] greater regional consistency among [Regional Entities]." OE Brief at 72. Compliance audits are

just one of many tools for effecting change in future performance of a registered entity. Other CIP-related activities NERC has engaged in, such as training and educational activities for industry on CIP requirements and cyber security threats (*see* NERC Initial Brief at 81-82) also are directed to improving the performance of registered entities in the cyber security area. In addition, there are other activities such as creation and revision of the RSAWs, CIP auditor training, development and issuance of CANs, review of the CIP audit reports from all Regional Entities, and review of possible CIP violations identified by the Regional Entities, that NERC has used to ensure consistency among the Regional Entities in their enforcement of the CIP standards.

Finally, OE ignores the significance of the evidence that, in fact, the Regional Entity CIP compliance programs have been very active in identifying violations of the CIP standards over the last two years since registered entities became obligated to be in auditable compliance with the CIP standards (NERC Brief at 84), and OE offers no response to the fact that NERC has significantly increased its CIP staffing and budget since 2010 (*id*. at 85-86).

J. NERC Activities

The arguments in the Audit Report and the OE Brief concerning the Audit Findings on this topic have been addressed in either or both of NERC's Initial Brief or the discussion of the recommendations on this topic in §III.D above. Although NERC is agreeing to take various actions based on the recommendations, there is no basis for any audit findings that NERC's performance was deficient in this area. NERC notes that the discussion on this topic in the OE Brief is considerably more restrained than the discussion in the Audit Report (which is turn was more restrained than the discussion in the Draft Audit Report, after Audit Staff received and considered NERC's comments on the Draft Audit Report). The OE Brief emphasizes that "the Audit Report did not suggest that the Commission revisit its acceptance of NERC's six broad program areas as statutory." OE Brief at 77.

K. NERC as the Electric Sector Information Sharing and Analysis Center

All of the arguments in the Audit Report and the OE Brief concerning the Audit Findings on this topic have been addressed in either or both of NERC's Initial Brief or the discussion of the recommendations on this topic in §III.E.2 above. The two points listed in the second full paragraph on page 83 of the OE Brief will be addressed through NERC's compliance with Recommendation 39 and the additional conditions proposed by OE that NERC has agreed to.

V. Conclusion

For the reasons set forth in the Initial Brief and this Reply Brief of the North American Electric Reliability Corporation, NERC respectfully requests that the Commission issue an order adopting the agreed audit recommendations and related conditions (where applicable), and adopting NERC's versions of the recommendations on which there is not agreement.

Respectfully submitted,

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APPENDIX A

STATUS OF AGREEMENT ON

AUDIT STAFF'S RECOMMENDATIONS

No.	Audit Staff Recommendation	NERC Recommendation	Status
1	Establish more robust procedures and controls over NERC's use of working capital reserves.	Establish more robust procedures and controls over NERC's use of working capital reserves.	Agreed (no difference) as to Recommendation text; disagree on implementation.
2	Develop a transparent process that permits the Commission, the BOT and stakeholders opportunity to review the expenditure of funds approved for specific statutory activities to be redirected to unbudgeted activities, and develop and obtain Board approval of enhanced guidelines governing such expenditures, including criteria for determining when Board and Commission approval is required.	Continue to make improvements in budget transparency that informs the Commission, the Board and stakeholders concerning the expenditure of funds approved for specific budgeted activities on unbudgeted activities, and develop and obtain Board approval of enhanced guidelines governing such expenditures, including criteria for determining when Board approval is required.	Disputed.
3	Request budgetary funds for activities initiated between budget cycles that were not included in the annual budget filing in a manner similar to section 1108 of the NERC Rules of Procedure (ROP).	NERC deleted this recommendation.	Audit Staff accepts deletion of this Recommendation if Audit Staff Recommendation 2 is adopted; NERC does not accept Audit Staff Recommendation 2.
4	Increase the granularity of the NERC budget filings by: (1) breaking out significant cost categories in its expenses; (2) identifying proposed budgeted expenditures, at a minimum, on a project specific basis; and (3) separating working capital reserves needed for operations from working capital reserves needed for contingencies and identifying those contingencies.	Increase the granularity of the NERC budget filings by: (1) breaking out budgeted expenses, such as budgeted contractors and consultant expenditures, into more detailed cost categories; and (2) separating working capital reserves needed for operations from working capital reserves needed for contingencies to the extent they are known during business planning.	Disputed.
5	Increase the granularity of the NERC true-up filings in line with the budget filings.	Increase the granularity of the NERC true-up filings in line with the budget filings.	Agreed (no difference).

6	Increase the level of NERC review of proposed Regional Entity business plans and budgets, including qualitative and quantitative analyses, with a specific focus on increasing the amount of review provided by NERC's statutory program departments to the business plans and budget of their counterpart Regional Entity functions.	Increase the level of NERC review of proposed Regional Entity business plans and budgets, including qualitative and quantitative analyses, with a specific focus on increasing the amount of review provided by NERC's statutory program departments to the business plans and budget of their counterpart Regional Entity functions.	Agreed (no difference).
7	Establish policies and procedures for using information gained and lessons learned from NERC's oversight of Regional Entity operations in the review process for Regional Entity business plans and budgets.	Establish policies and procedures for using information gained and lessons learned from NERC's oversight of Regional Entity operations in the review process for Regional Entity business plans and budgets.	Agreed (no difference).
8	Provide budget changes and recommendations to the Regional Entities during the early stages of the Regional Entity budget processes so there is sufficient time to incorporate NERC's recommendations prior to final review and approval of such business plans and budgets by the Board.	Provide budget changes and recommendations to the Regional Entities during the early stages of the Regional Entity budget processes so there is sufficient time to incorporate NERC's recommendations prior to final review and approval of such business plans and budgets by the Board.	Agreed (no difference).
9	Continue to implement a time reporting system with the functionality to track employees' time based on the amount of time spent on specific projects or activities and on statutory or non-statutory reliability activities.	Continue implementation of a time reporting system with the functionality to track employees' time based on the amount of time spent on functional activities or key specific projects.	Disputed.
10	Develop and implement more comprehensive policies and procedures governing employee time reporting and tracking.	Develop and implement more comprehensive policies and procedures governing employee time reporting and tracking.	Agreed (no difference).
11	Provide training to NERC employees on the proper use of the new time reporting	Provide training to NERC employees on the proper use of the new time reporting	Agreed (no difference).

	system.	system.	
12	Develop project and business activity codes to allow better project management, including tracking of operating expenses to project-specific levels.	NERC deleted this recommendation.	Disputed.
13	To the extent consistent with good business practices, NERC should expeditiously implement functionality in the expense reporting software to allow the tracking of expenses on a project and activity basis.	Conduct a cost-benefit analysis in 2013 of implementing a more detailed project level budgeting and accounting system.	Disputed.
14	Improve automated controls in its accounting system, such as flags and alerts, to ensure proper accounting classifications, efficiency, and oversight for reporting and analyzing expenses.	Improve automated controls in its accounting system, such as flags and alerts, to ensure proper accounting classifications, efficiency, and oversight for reporting and analyzing expenses.	Agreed (no difference).
15	Establish a comprehensive, single-source accounting manual consisting of comprehensive accounting policies, procedures, controls, guidance, and other materials to ensure costs are properly classified, reviewed, approved, and presented accurately in NERC's accounting system, financial statements, and budget filings.	Establish a comprehensive, single-source accounting manual consisting of comprehensive accounting policies, procedures, controls, guidance, and other materials to ensure costs are properly classified, reviewed, approved, and presented accurately in NERC's accounting system, financial statements, and budget filings.	Agreed (no difference).
16	Continue to conduct on a routine and periodic basis a thorough review of its entire organization to determine the particular skills and competencies that are required to perform the necessary tasks of each organizational position.	Continue to conduct on a routine and periodic basis a thorough review of its entire organization to determine the particular skills and competencies that are required to perform the necessary tasks of each organizational position.	Agreed (no difference).
17	Continue to perform routine and periodic updates to employee compensation studies, using comparability data that target the required	Continue to perform routine and periodic updates to employee compensation studies, using comparability data that target the required	Agreed (no difference).

	skill sets and competences needed to carry out NERC's mission as the ERO.	skill sets and competences needed to carry out NERC's mission as the ERO.	
18	Use total compensation and update policies to reflect the use of total compensation as the relevant guideline in assessing salaries, retirement benefits, bonuses and other forms of compensation.	Use total compensation, and update policies to reflect the use of total compensation as the relevant guideline in assessing salaries, retirement benefits, bonuses and other forms of compensation.	Agreed (no difference).
19	Enhance formal policies, procedures, and guidance governing expenses incurred by employees to include the following: (1) developing a well-documented reasonableness standard for employee and Trustee meal, hotel and other travel expenses, including guidance on what constitutes a reasonable cost; (2) detailed steps for reviewing and approving expenses; and (3) other necessary procedures to provide clear guidance to employees.	Enhance formal policies, procedures, and guidance governing expenses incurred by employees to include the following: (1) developing well-documented reasonableness standards for employee and Trustee meal, hotel and other travel expenses, including guidance on what constitutes a reasonable cost; (2) detailed steps for reviewing and approving expenses; and (3) other necessary procedures to provide clear guidance to employees.	Agreed (no difference).
20	In the enhancements under recommendation 19, NERC should evaluate the effectiveness of dividing its process for approving expenses into two steps, leaving managers responsible for approving the purpose and rationale for incurring expenses and designating accounting staff to be responsible for evaluating the reasonableness of expenses.	In the enhancements under recommendation 19, NERC should evaluate the effectiveness of dividing its process for approving expenses into two steps, leaving managers responsible for approving the purpose and rationale for incurring expenses and designating accounting staff to be responsible for evaluating the reasonableness of expenses.	Agreed (no difference).
21	Devise formalized recruitment and hiring policies, procedures, and strategies that address, among other things, controls over the total compensation packages, salary, retention bonuses, benefits, and other accommodations offered to	Devise formalized recruitment and hiring policies, procedures, and strategies that address, among other things, controls over the total compensation packages, salary, retention bonuses, benefits, and other accommodations offered to	Agreed (no difference).

	prospective employees. The policies and procedures should also address the qualifications and experience of prospective employees.	prospective employees. The policies and procedures should also address the qualifications and experience of prospective employees.	
22	Explicitly budget for employee entertainment expenses by including line items of sufficient granularity in the budget filings.	Explicitly budget for employee rewards and recognition and entertainment expenses by including line items of sufficient granularity in the budget filings.	NERC version agreed to with condition that NERC develop and submit clear policies and procedures that identify the nature of the costs to be recorded as employee rewards and recognition, and develop and file policies for how NERC will provide such rewards and recognition.
23	Use miscellaneous expense accounts to track entertainment expenses separately from business-related expenses in its accounting system.	Use miscellaneous expense accounts to track expenses which are for employee rewards and recognition or entertainment separately from other business-related expenses in its accounting system.	NERC version agreed to with condition that NERC develop and submit clear policies and procedures that identify the nature of the costs to be recorded as employee rewards and recognition, and develop and file policies for how NERC will provide such rewards and recognition.
24	Ensure entertainment expenses are clearly and transparently presented to the BOT, Commission, and stakeholders in the budget before these costs are incurred.	Ensure rewards and recognition expenses and entertainment expenses are clearly and transparently presented to the Board, Commission, and stakeholders in the budget before these costs are incurred.	NERC version agreed to with condition that NERC develop and submit clear policies and procedures that identify the nature of the costs to be recorded as employee rewards and recognition, and develop and file policies for how NERC will provide such rewards and recognition.
25	Consider returning to the performance-based method of compensating BOT members until NERC gains the necessary experience to support a change to a flat-fee compensation model.	NERC deleted this recommendation.	Disputed.
26	Establish a method for	NERC deleted this	Disputed.

	tracking BOT time and participation on BOT activities to be able to properly evaluate and quantify the performance of each trustee.	recommendation.	
27	Implement the planned BOT tracking software to assist in measuring BOT participation and reducing undue administrative burden.	NERC deleted this recommendation.	Disputed.
28	Conduct an analysis of BOT participation and effort based on a time study using actual time spent during BOT activities, or a representative study of the actual time spent and implement a compensation methodology that pays BOT members reasonably for performance of their duties.	Continue to conduct annual reviews of the Board compensation plan, taking into account Board time and participation on Board activities and conduct periodic market studies regarding the structure and amount of Board compensation.	Disputed.
29	Estimate and include in its annual budgets an amount of funding to cover expenses in connection with Board and Board committee meetings and other NERC activities that it deems appropriate and seek approval for such funding.	Estimate and include in its annual budgets an amount of funding to cover expenses for Trustees in connection with Board and Board committee meetings and other NERC activities that it deems appropriate and seek approval for such funding.	Disputed. Audit Staff modified version deletes "for Trustees" from NERC version.
30	Track the expenses actually incurred on the BOT to the budgeted amounts for such expenses.	Track the expenses actually incurred on the BOT to the budgeted amounts for such expenses.	Agreed (no difference).
31	Develop appropriate policies for the giving of gifts, funded from NERC's own resources or paid by any NERC officer or employee to a Trustee.	Develop appropriate policies for the giving of gifts, funded from NERC's own resources or paid by any NERC officer or employee to a Trustee.	Agreed (no difference).
32	Determine its retirement obligations using relevant comparability and other data that reflects current market conditions.	Determine its retirement obligations using relevant comparability and other data that reflects current market conditions.	Agreed (no difference).
33	Work with the BOT to craft total remuneration policy based on principles of total	Work with the Board to craft a total remuneration policy based on principles of total	Agreed (no difference).

	compensation, electric power industry practices, and other relevant factors. This policy should include procedures to justify that all retirement plan contribution levels are appropriate and reasonable.	compensation, electric power industry practices, and other relevant factors. This policy should include procedures to justify that all retirement plan contribution levels are appropriate and reasonable.	
34	Develop an alternative mechanism for addressing retirement contributions in excess of the IRS cap that maintains the payment as a retirement benefit and not as additional compensation to the employee.	Continue to use the mechanism that has been adopted and consider additional mechanisms to allow employees to address tax deferred retirement saving of contributions in excess of the IRS cap on 401(k) contributions.	Agreed to NERC version.
35	Conduct an assessment of existing CIP-related staffing to ensure that NERC staff work aligns with section 215 activities, and that there are adequate resources to accomplish CIP work.	Conduct an assessment of existing CIP-related staffing levels to ensure there are adequate resources to accomplish CIP work, particularly with respect to Regional Entity CIP auditing and other Regional Entity CIP-related CMEP activities.	Agreed to NERC version.
36	Devote greater resources to carry out its duties under the CMEP as to the CIP-002 through CIP-009 standards and provide effective oversight of CIP CMEP activities by the Regional Entities.	Devote greater resources to carry out its duties under the CMEP as to the CIP-002 through CIP-009 standards and provide effective oversight of CIP CMEP activities by the Regional Entities.	Agreed (no difference).
37	Establish written criteria for determining whether a reliability activity should be funded under section 215 through coordination and discussion with Commission staff and stakeholders. Submit to audit staff the criteria established from this collaborative process.	Establish written criteria for determining whether an activity is a statutory activity and should be funded under section 215 through an open and transparent process initiated by NERC.	Audit Staff and NERC disagree on how to implement this Recommendation; however, NERC now proposes to implement it via a March 1, 2013 compliance filing with the Commission.
38	Identify all ERO activities funded under section 215, detailing at a minimum: the purpose of the activity, a description, and the justification for using	In its annual business plan and budget filings, provide an explanation as to why the proposed activities to be undertaken by each program area for the budget year are	Disputed.

	section 215 funding. Submit all documentation to audit staff for these reliability activities.	statutory, including, at a minimum: a description and the purpose of the major activities to be undertaken by each program area and an explanation for why the activity is a statutory activity.	
39	Work with Commission staff to define NERC's role as the ES-ISAC, to evaluate NERC's role as the ES-ISAC in connection with NERC's other roles as the ERO, and to clearly lay out the Commission's role in overseeing the ES-ISAC.	Provide additional information in NERC's 2013 Business Plan and Budget regarding NERC's role as the ES-ISAC; and initiate an open and transparent process to provide opportunities for stakeholder input regarding NERC's role as the ES-ISAC, including (1) the impact, if any, on NERC's compliance-related activities of "walling off" certain staff from the ES-ISAC activities; and (2) access of FERC staff to ES-ISAC information for situational awareness and compliance purposes.	Agreed to NERC version with condition that a clarification of the Commission's ES-ISAC oversight responsibilities is clearly laid out as part of this process, and that the Commission has an opportunity to expressly consider and approve or disapprove ES-ISAC's statutory funding eligibility.
40	Evaluate the impact on compliance-related activities of "walling off" certain staff from these activities, and modify NERC's current proposal for redefining the operation of the ES-ISAC to include clear guidance on how the "walled off" sub-division will interact with the ERO.	NERC deleted this recommendation because it is subsumed by NERC's proposed no. 39.	Deletion agreed to with the condition stated in 39 above.
41	Clarify the flow of information between the ES-ISAC and the FERC staff for situational awareness and compliance purposes.	NERC deleted this recommendation because it is subsumed by NERC's proposed no. 39.	Deletion agreed to with the condition stated in 39 above.
42	Determine whether the funding of the ES-ISAC, in whole or in part, should be treated as non-statutory and, if so, how to manage such funding.	NERC deleted this recommendation because it is subsumed by NERC's proposed no. 39 and proposed nos. 37 and 38 in the preceding section on "NERC Activities."	Deletion agreed to with the condition stated in 39 above.

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Chicago, Illinois, this 10th day of September, 2012.

/s/ Owen E. MacBride
Owen E. MacBride

Attorney for North American
Electric Reliability Corporation

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RM06-16-000

September 13, 2012

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005-3801

Attention: Holly A. Hawkins
Assistant General Counsel for Standards and Critical Infrastructure Protection

Reference: Filing for Approval of Errata Change to NERC Glossary of Terms

Dear Ms. Hawkins:

On March 16, 2012, the North American Electric Reliability Corporation (NERC) submitted a filing that requested that the NERC Glossary of Terms be amended to modify the definition of "Interconnection Reliability Operating Limit (IROL)" by replacing the reference to "Cascading Outages" with "Cascading outages."

NERC notes that the proposed term "Cascading Outages" was remanded in the Commission Order[1] which approved the term "IROL".

Notice of this filing was issued on July 25, 2012, with protests and interventions due on or before August 15, 2012.

Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.214. No protests were filed.

[1] *Facilities Design, Connections and Maintenance Reliability Standards*, 121 FERC ¶ 61,296 (December 27, 2007).

NERC's uncontested filing is approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability, under 18 C.F.R. § 375.303, as of the date of this order.

This action shall not be construed as accepting any other contingency plan pursuant to 18 C.F.R. § 375.303(a)(1)(i) or any other data or report pursuant to 18 C.F.R. § 375.303(b)(3)(iv). This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order pursuant to 18 C.F.R. § 385.713.

Sincerely,

Joseph H. McClelland, Director
Office of Electric Reliability

20120913-3010 FERC PDF (Unofficial) 09/13/2012

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD12-4-000

September 13, 2012

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005-3801

Attention: Holly A. Hawkins
Assistant General Counsel for Standards and Critical Infrastructure Protection

Reference: Petition for Approval of Errata Changes to Seven Reliability Standards

Dear Ms. Hawkins:

On June 5, 2012, the North American Electric Reliability Corporation (NERC) submitted a filing that requested approval of errata changes to seven Reliability Standards as follows:

- BAL-005-0.1b Automatic Generation Control - replace Appendix 1 with a correct version of a Commission-approved interpretation, and make an internal reference correction in the interpretation;
- EOP-001-0b Emergency Operations Planning - update the title of Attachment 1 and correct internal references thereto, and correct an incorrect internal reference in Appendix 2;
- EOP-001-2b Emergency Operations Planning - update the title of Attachment 1 and correct internal references thereto, and update references in Appendix 1 to the correct standard;
- EOP-002-3 Capacity and Energy Emergencies - update the title of Attachment 1 and correct internal references thereto; remove parenthetical reference to a retired Attachment to another standard;
- IRO-005-3a Reliability Coordination – Current Day Operations - remove outdated internal reference in two Measures;

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• PER-001-0.1 Operating Personnel Responsibility and Authority - correct transposition error of two words in a Measure; and

• TOP-002-2b Normal Operations Planning - remove incorrect language in Effective Date section of Exhibit B; remove two retired sub-requirements and parenthetical reference thereto, and correct Measure to reflect these changes.

Each change above is also accompanied by a revision to the numbering of the Reliability Standard and version history. Each errata change was submitted to NERC's Standards Committee, which found that the proposed corrections do not change the scope or intent of the associated Standards, nor do they have a material impact on the end users of the Standards.

Notice of this filing was issued on June 6, 2012, with protests and interventions due on or before June 26, 2012.

Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.214. No protests were filed.

NERC's uncontested filing is approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability, under 18 C.F.R. § 375.303, as of the date of this order.

This action shall not be construed as accepting any other contingency plan pursuant to 18 C.F.R. § 375.303(a)(1)(i) or any other data or report pursuant to 18 C.F.R. § 375.303(b)(3)(iv). This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order pursuant to 18 C.F.R. § 385.713.

Sincerely,

Joseph H. McClelland, Director
Office of Electric Reliability

Document Content(s)

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Revisions to Electric Reliability	**)**	**Docket Nos. RM12-6-000**
Organization Definition of Bulk Electric System	**)**	**RM12-7-000**
And Rules of Procedure		

REPLY COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

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September 19, 2012

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Revisions to Electric Reliability	**)**	**Docket Nos. RM12-6-000**
Organization Definition of Bulk Electric System	**)**	**RM12-7-000**
And Rules of Procedure	**)**	

REPLY COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

The North American Electric Reliability Corporation ("NERC")[1] hereby provides these reply comments in response to the comments submitted on September 4, 2012 on the Federal Energy Regulatory Commission's ("FERC" or "Commission") June 22, 2012, Notice of Proposed Rulemaking ("NOPR")[2] regarding revisions to the Electric Reliability Organization ("ERO") Definition of Bulk Electric System ("BES Definition") and Rules of Procedure.

I. BACKGROUND

In the NOPR, the Commission proposed to approve a modification to the currently-effective definition of "bulk electric system."[3] The proposed modification to the definition removes language allowing for regional discretion in the currently-effective bulk electric system definition. The proposed revised definition also establishes a bright-line threshold so that the

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[1] The Federal Energy Regulatory Commission certified NERC as the electric reliability organization ("ERO") in its order issued on July 20, 2006 in Docket No. RR06-1-000. *North American Electric Reliability Corporation*, 116 FERC ¶ 61,062 (2006).

[2] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, 139 FERC ¶ 61,247 (June 22, 2012) ("NOPR").

[3] NERC proposes the following "core" definition of bulk electric system:

> Unless modified by the [inclusion and exclusion] lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

"bulk electric system" will include facilities operated at 100 kV or higher, if they are Transmission Elements, or connected at 100 kV or higher, if they are Real Power or Reactive Power resources.[4] The new proposed definition contains specific inclusions and exclusions to provide clarity in the definition that the facilities described in certain configurations are included in or excluded from the BES Definition. Comments on the NOPR were due on September 4, 2012, and NERC and a significant number of entities submitted comments. Pursuant to Rule 212, NERC respectfully offers these reply comments in order to clarify several issues raised by other commenters.

II. COMMENTS

NERC offers comments on the following: (1) the extent of the Commission's jurisdiction in connection with the scope of the BES Definition, (2) the exceptions process as set forth in the Rules of Procedure, and (3) the scope of Phase 2 of the BES Definition.[5] In addition, several entities offer revised language to the BES Definition for consideration by the Commission.[6] As the Commission has noted in prior instances, such comments should have been submitted during the standard development process and the Commission should reject such comments.[7]

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[4] Unless otherwise designated, all capitalized terms shall have the meaning set forth in the Glossary of Terms Used in NERC Reliability Standards, available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

[5] In response to the request for clarification by Alameda Municipal Power regarding the ability of parties to seek exceptions for proposed facilities, NERC notes that Section 1.1 provides that an entity planning the connection of a new Element for which it believes an Exception would be appropriate may request an Exception prior to commercial operation of the Element. *See Comments of Alameda Municipal Power* at 17 ("AMP seeks clarification that parties may seek exceptions for proposed facilities, and not just for existing facilities. Allowing exceptions to be sought for proposed facilities would provide an opportunity for entities to make reasoned decisions about planned system improvements.").

[6] *See e.g.,Comments of the PSEG Companies* at 2.

[7] See *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006)("we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission.").

A. The BES Definition Accurately Reflects the Extent of the Commission's Jurisdiction

With respect to comments submitted regarding the extent of the Commission's jurisdiction under Section 215 of the Federal Power Act ("FPA"),[8] NERC notes that the exemption of local distribution facilities in the BES Definition and the exclusion of radial systems as described in Exclusion E1, appropriately reflect the Commission's jurisdiction under Section 215.[9] As the Commission acknowledged in Order No. 743, Congress has specifically exempted facilities used in the local distribution of energy from the definition of Bulk-Power System, and such facilities accordingly cannot be included as part of the BES as defined by NERC.[10]

The sole fact that industrial generators are intrastate facilities that only serve load does not mean that they are excluded from the Commission's jurisdiction under Section 215. Section 215 applies to both interstate and intrastate facilities -- whether or not Section 215 applies to industrial generators depends on whether they are users, owners or operators of the bulk-power system and the current criteria for that determination are set forth in NERC's Compliance

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[8] Several commenters state that because industrial generators are intrastate facilities that only serve the owner's load, they are excluded from the jurisdiction of the Commission. *See Comments of Barrick Goldstrike Mines Inc.*, at 13 ("Accordingly, these intrastate industrial generators are not now subject to FERC jurisdiction and NERC's reliability rules must therefore stay within the limits imposed by the statutory text set forth by Congress."); *Comments of the Industrial Users of Utah* at 3-4 ("Because these industrial generators are intrastate facilities that serve only the owner's load, they are excluded from the jurisdiction of FERC and NERC. ").

[9] FPA Section 215(b)(1), titled "Jurisdiction and Applicability," describes the Commission's reliability jurisdiction as follows:

> The Commission shall have jurisdiction . . . over . . . all users, owners and operators of the bulk-power system, including but not limited to the entities described in section 201(f), for purposes of approving reliability standards established under this section and enforcing compliance with [FPA section 215]. All users, owners and operators of the bulk-power system shall comply with reliability standards that take effect under this section.
>
> 16 U.S.C. § 824o(b)(1).

[10] *See* Order No. 743, 133 FERC ¶ 61,150 at P 37 (2010); *see also* Order No. 743-A, 134 FERC ¶ 61,210 at P 58 ("[W]e reiterate that facilities used for local distribution are excluded from the Bulk-Power System definition under *section 215*, and thus are excluded from the bulk electric system.")(2011).

Registry. NERC respectfully submits that the BES Definition appropriately reflects the exemption of facilities used in local distribution and accurately reflects the Commission's jurisdiction.

B. The Exceptions Process is Sufficiently Robust and Transparent

1. The Limitation on the Right to File an Exception Request is Appropriate

Section 1.1 of Appendix 5C to the NERC Rules of Procedure details who is entitled to file an Exception Request. The exceptions process is based on the NERC Compliance Registry and the NERC Functional Model. The right to file an Exception Request is not limited to the Owner of the Element that is the subject of the Exception Request. Rather, the Regional Entity or a Registered Entity performing reliability functions that would have the Element within its Scope of Responsibility may submit an Exception Request with respect to the Element.

> The Owner of the Element to which the Exception Request applies or, with respect to an Element owned by another Registered Entity, any Regional Entity, Planning Authority ("PA"), Reliability Coordinator ("RC"), Transmission Operator ("TOP"), Transmission Planner ("TP") or Balancing Authority ("BA") that has (or will have upon inclusion of the Elements in the BES) the Elements covered by an Exception Request within its Scope of Responsibility may submit an Exception Request for the Element as provided in this Exception Procedure

Several commenters have raised concerns regarding the role of state commissions[11] and Regional Transmission Organizations/Independent System Operators ("RTOs/ISOs") within the

[11] *See Comments of the New York State Public Service Commission* at 7 ("the NOPR does not include any meaningful opportunities for the participation of states in the exception process for excluding facilities that are not necessary for the reliable operation of the interconnected transmission network. Because the states are appropriate entities that should be working with local Transmission Owners and/or regional reliability councils to identify local distribution facilities, the Commission should expressly provide for state involvement in any such process."); *Comments of the National Association of Regulatory Utility Commissioners* at 7 ("the Commission should direct NERC to amend the Rules of Procedure to ensure the relevant State regulatory authorities receive the same notice and access to information as Planning authorities and other entities and should have the same right to provide comment and input to the Regional Entity as is provided to other stakeholders.").

exceptions process.[12] NERC submits that the limitation on the right to file an Exception Request to the above-listed entities is appropriate. This procedure reflects an effective and efficient way to bring to bear the information required to process Exception Requests. RTOs and ISOs have the ability to file an Exception Request where they are acting in their capacity as Planning Authorities, Reliability Coordinators, Transmission Operators, Transmission Planners or Balancing Authorities. The exceptions process is technical and is based on engineering expertise, and these are the necessary parties with the required information. State commissions have other means and methods at their disposal for working with entities to identify candidates for an Exception Request. For these reasons, the limitation on the right to file an Exception Request is appropriate and administratively efficient.

2. Notice Regarding Exception Requests is Sufficient

Commenters have stated that state regulatory authorities should receive notice and access to information regarding Exception Requests.[13] Attachment 9 of NERC's Petition, (The Development Process and Basis for the RoP Team Recommended Provisions- How Stakeholder Comments were Considered and Addressed), includes a discussion (at p. 6-7) regarding the role of state regulators within the exceptions process.

> The Team specifically provided that (1) detailed notice of any request would be provided to every Registered Entity with reliability oversight obligation for the Element subject to the Request and (2) general information about the request will be publicly posted. The RoP team believes that it has achieved sufficient balance between the protection of CEII and other confidential information and the need to have a process as transparent as possible to ensure consistency. The RoP Team believes that third parties (including state regulatory agencies) will have adequate opportunity to provide comments regarding the request without formally participating in the process

[12] *See e.g., Comments of the Midwest Independent Transmission System Operator, Inc.* at 9-13.

[13] *See infra.* at n.11.

This process provides as much transparency as possible, while maintaining protection and confidentiality of information. As noted above, NERC maintains that it is unnecessary for there to be an explicit role for specific third parties within the exceptions process and asserts that the notice provided with respect to Exception Requests is sufficient.

3. <u>The Requirements for Submitting an Exception Request Must be Consistent</u>

The Midwest Independent Transmission System Operator, Inc. suggests that the Commission should "lower the requirements for RTOs when filing exception requests for exclusion and/or inclusion of facilities within their scope of responsibility."[14] NERC disagrees. This concept is inconsistent with the need to provide a consistent and clear basis for determining the outcome of exception requests. The Rules of Procedure require the submitting entity to include a common set of data and information with each exception request (the "Detailed Information to Support an Exception Request"). The Detailed Information is intended to ensure that a consistent baseline of technical information is provided to the Regional Entity and NERC with all exception requests, in addition to the specific information and arguments submitted by the submitting entity in support of its exception request. For these reasons, NERC asserts that it is appropriate that the information required for an exception request is the same, regardless of the identity of the submitter.

C. Phase 2 of the BES Definition

A number of comments submitted in response to the BES NOPR raise issues that are currently being addressed by Phase 2 of the BES Definition.[15] Project 2010-17, Definition of

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[14] *Comments of the Midwest Independent Transmission System Operator, Inc*. at 12.

[15] *See e.g*., *Comments of Consumers Energy Company* at 3 ("the scope of Inclusion I4 is unclear"); *Comments of Barrick Goldstrike Mines, Inc.* at 5 ("It is unclear what 'not . . . non-retail generation' means.")*; Comments of the Dow Chemical Company* at 1 ("the requirement that power may only flow into, and not out of, a local network should be clarified to apply only to power that originates outside of, and flows through, a local network."); *Comments of the New England States Committee on Electricity* at 3("NERC's proposal provides no technical

Bulk Electric System was divided into phases in order to meet the Commission's directives in Order Nos. 743 and 743-A, while also addressing the concerns raised by stakeholders in the standard development process. As outlined in the Phase 2 Standards Authorization Request ("SAR"),[16] Phase 2 of the BES Definition will include an analysis of the-following issues which were identified during the development of Phase 1:

- Development of a technical justification to set the appropriate threshold for Real and Reactive Power Resources necessary for the reliable operation of the BES;
- Determination of whether there is a need for the BES Definition to encompass a contiguous BES;
- Determination of whether there is a technical justification to revise the current 100 kV bright-line voltage level;
- Determination of whether there is a technical justification to support allowing power flow out of the local network under certain conditions and if so, what the maximum allowable flow and duration should be.

In addition, Phase 2 will provide clarity to the following:

- The relationship between the BES Definition and the ERO Statement of Compliance Registry Criteria established in Order No. 693;
- The use of the term "non-retail generation;"
- The language for Inclusion I4 on dispersed power resources;
- The appropriate points of demarcation between Transmission, Generation and Distribution.

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justification for relying on the bright-line approach."); *Comments of the New York State Public Service Commission* at 3 ("The NOPR lacks a technical justification for a 100 kV bright-line definition."); *Comments of Southern Company Services, Inc.* at 5 ("further consideration should be given as to whether inclusion I2 should be made more consistent with the Registry Criteria.").

[16] *See* http://www.nerc.com/filez/standards/Project2010-17_BES.html; *see also*, http://www.nerc.com/docs/standards/sar/BES_Definition_Fact_Sheet_20110920_final.pdf.

Phase 2 may also include other improvements to the BES Definition. NERC encourages commenters to participate in the standard development process and respectfully requests that the Commission continue to allow these issues to be addressed in Phase 2 of the BES Definition.

III. CONCLUSION

For the reasons stated above, NERC respectfully requests that the Commission accept these comments for consideration.

Respectfully submitted,

/s/ Stacey Tyrewala

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Dated: September 19, 2012

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 19th day of September, 2012.

/s/ Stacey Tyrewala
Stacey Tyrewala
Attorney for North American Electric Reliability Corporation

140 FERC ¶ 61,203
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM12-12-000]

Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding

(Issued September 20, 2012)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: Under section 215 of the Federal Power Act (FPA),[1] the Federal Energy Regulatory Commission (Commission) proposes to approve regional Reliability Standard PRC-006-NPCC-1 (Automatic Underfrequency Load Shedding). The North American Electric Reliability Corporation (NERC) submitted the proposed regional Reliability Standard to the Commission for approval. The proposed regional Reliability Standard applies to generator owners, planning coordinators, distribution providers, and transmission owners in the Northeast Power Coordinating Council Region and is designed to ensure the development of an effective automatic underfrequency load shedding (UFLS) program to preserve the security and integrity of the Bulk-Power System during declining system frequency events, in coordination with the NERC continent-wide UFLS Reliability Standard PRC-006-1. The Commission also proposes

[1] 16 U.S.C. 824(o) (2006).

to approve the associated violation risk factors and violation severity levels, implementation plan, and effective dates proposed by NERC.

DATES: Comments are due [INSERT DATE 60 days after publication in the **FEDERAL REGISTER**]

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

140 FERC ¶ 61,203
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding

Docket No. RM12-12-000

NOTICE OF PROPOSED RULEMAKING

(Issued September 20, 2012)

1. Under section 215 of the Federal Power Act (FPA), the Federal Energy Regulatory Commission (Commission) proposes to approve regional Reliability Standard PRC-006-NPCC-1 (Automatic Underfrequency Load Shedding). The North American Electric Reliability Corporation (NERC) submitted the proposed regional Reliability Standard to the Commission for approval. The proposed regional Reliability Standard applies to generator owners, planning coordinators, distribution providers, and transmission owners in the Northeast Power Coordinating Council (NPCC) Region and is designed to ensure the development of an effective automatic underfrequency load shedding (UFLS) program to preserve the security and integrity of the Bulk-Power System during declining system frequency events, in coordination with NERC's continent-wide UFLS Reliability Standard PRC-006-1.

2. The Commission also proposes to approve the associated violation risk factors (VRF) and violation severity levels (VSL), implementation plan, and effective dates proposed by NERC.

I. Background

A. Mandatory Reliability Standards

3. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards that are subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by NERC, subject to Commission oversight, or by the Commission independently.[2]

4. A Regional Entity may develop a Reliability Standard for Commission approval to be effective in that region only.[3] In Order No. 672, the Commission stated that:

> As a general matter, we will accept the following two types of regional differences, provided they are otherwise just, reasonable, not unduly discriminatory or preferential and in the public interest, as required under the statute: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) a regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System.[4]

[2] *See* 16 U.S.C. § 824o(e) (2006).

[3] 16 U.S.C. § 824o(e)(4). A Regional Entity is an entity approved by the Commission to enforce Reliability Standards under delegated authority from the ERO. *See* 16 U.S.C. § 824o(a)(7) and (e)(4).

[4] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 291, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006)).

5. On April 19, 2007, the Commission accepted delegation agreements between NERC and each of the eight Regional Entities.[5] In the order, the Commission accepted NPCC as a Regional Entity.

6. NERC Reliability Standard PRC-006-1 establishes continent-wide design and documentation requirements for UFLS programs that arrest declining frequency and assist recovery of frequency following system events leading to frequency degradation.

B. Proposed Regional Reliability Standard PRC-006-NPCC-1

7. On May 4, 2012, NERC petitioned the Commission to approve proposed regional Reliability Standard PRC-006-NPCC-1 and the associated VRFs and VSLs, effective dates, and implementation plan.[6] NERC states that the proposed regional Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest because it satisfies the factors set forth in Order No. 672, which the Commission applies when reviewing a proposed Reliability Standard.[7] NERC states that PRC-006-NPCC-1 also satisfies the additional criteria required for approval of regional Reliability

[5] *North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, *order on reh'g*, 120 FERC ¶ 61,239 (2007).

[6] Proposed regional Reliability Standard PRC-006-NPCC-1 is available on the Commission's eLibrary document retrieval system in Docket No. RM12-12-000 and on the NERC website, www.nerc.com. On August 3, 2012, NERC filed an errata attaching the proposed implementation plan.

[7] NERC Petition at 9-29 (citing Order No. 672, FERC Stats. & Regs. ¶ 31,204 at PP 323-335, 444).

Standards because it adds specificity not contained in the NERC continent-wide UFLS Reliability Standard PRC-006-1.[8]

8. Proposed regional Reliability Standard PRC-006-NPCC-1 has 23 requirements, each having an associated measure of compliance. The proposed standard also includes Figure 1, which includes a curve that establishes a threshold for setting underfrequency trip protection for generators in the portion of the NPCC Region in the Eastern Interconnection. NERC explains that the proposed regional Reliability Standard is based on the program characteristics defined within NPCC Directory #12 Underfrequency Load Shedding Program Requirements, which contains the criteria that govern the NPCC Automatic UFLS program that have been in place since June 26, 2009.[9] NERC states that the proposed regional Reliability Standard will achieve a coordinated, comprehensive UFLS region-wide consistent program within the NPCC Region and provides the regional requirements necessary to achieve and facilitate the broader program characteristics contained in the requirements of the NERC Reliability Standard PRC-006-1.[10] NERC states that the proposed regional Reliability Standard is designed to work in conjunction with and augment Reliability Standard PRC-006-1 by mitigating the consequences of an underfrequency event, while accommodating differences in system transmission and distribution topology among NPCC planning coordinators due to

[8] NERC Petition at 29-30.

[9] *Id.* at 11.

[10] *Id.* at 29-30.

historical design criteria, makeup of load demands, and generation resources.[11] NERC further states that the proposed regional Reliability Standard also facilitates uniformity, compliance, and clearly delineates what the applicable entities' requirements are within the NPCC Region to achieve a robust, reliable and effective UFLS program.[12]

9. NERC also proposes VRFs and VSLs for each requirement of the proposed regional Reliability Standard and an implementation plan and effective dates. NERC states that these proposals were developed and reviewed for consistency with NERC and Commission guidelines.

10. NERC proposes two effective dates for the proposed regional Reliability Standard. NERC states that Requirements R1 through R7 would become effective on the first day of the first calendar quarter following applicable regulatory approval but no earlier than January 1, 2016. The implementation plan states that the January 1, 2016 effective date for Requirements R1 through R7 is meant to allow for completion of the on-going six-year implementation period for NPCC Directory #12 Underfrequency Load Shedding Program Requirements.[13] The implementation plan provides that the plan for "this

[11] *Id*. at 30.

[12] *Id*.

[13] NPCC Directory #12 Underfrequency Load Shedding Program Requirements contains the pre-existing criteria that govern the NPCC Automatic UFLS program developed by the NPCC Working Group on Inter-Area Dynamic Analysis. NERC Petition at 11. The implementation plan was submitted as an exhibit to the August 3, 2012 NERC errata filing. As found on the Commission's eLibrary system in Docket No. RM12-12-000, the implementation plan is located in Exhibit A (PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding Regional Reliability Standard Proposed and

(continued)

standard is based, in part, on the timelines reflected in the existing and ongoing Implementation Plan for NPCC Directory #12 absent the annual milestones required by Directory #12."[14] With respect to Requirements R8 through R23, NERC proposes that they become effective the first day of the first calendar quarter two years following applicable regulatory approval.

II. Discussion

A. PRC-006-NPCC-1

11. Pursuant to FPA section 215(d)(2), we propose to approve regional Reliability Standard PRC-006-NPCC-1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. Proposed regional Reliability Standard PRC-006-NPCC-1 is designed to operate in conjunction with the NERC continent-wide UFLS Reliability Standard PRC-006-1 by mitigating the consequences of underfrequency events, while accommodating differences in system transmission and distribution topology among NPCC planning coordinators due to historical design criteria, makeup of load demands, and generation resources.

12. The proposed regional Reliability Standard includes requirements not found in the corresponding NERC continent-wide UFLS Reliability Standard PRC-006-1 that are more stringent than Reliability Standard PRC-006-1 and accommodate differences in

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Implementation Plan for Approval) of the errata filing beginning at page 29 of the PDF electronic file submitted by NERC.

[14] *Id*.

system transmission and distribution topology among NPCC planning coordinators due to historical design criteria, makeup of load demands, and generation resources.[15]

13. For example, the generator underfrequency trip threshold in PRC-006-NPCC-1, Requirement R13 is more stringent than the threshold specified in the continent-wide Reliability Standard PRC-006-1. Requirement R13 of the proposed regional Reliability Standard requires generator owners to set their generator underfrequency trip relay setting below the generator underfrequency trip protection settings threshold shown in Figure 1, except as otherwise provided in Requirements R16 and R19. This requirement is more stringent than the corresponding requirement in Reliability Standard PRC-006-1, Requirement R4, because the continent-wide Reliability Standard requires a higher generator underfrequency trip setting.[16] In addition, the continent-wide Reliability Standard PRC-006-1 does not require generator owners to have compensatory load shedding provisions if their units trip above the underfrequency tripping threshold requirements specified in PRC-006-1, Attachment 1. By contrast, proposed regional Reliability Standard PRC-006-NPCC-1, Requirement R16.3, requires that each generator owner of existing non-nuclear units "[h]ave compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the

[15] NERC Petition at 29-30.

[16] Higher underfrequency trip settings result in generators tripping offline sooner than lower underfrequency trip settings.

loss of their generator due to early tripping."[17] The proposed regional Reliability Standard PRC-006-NPCC-1 is therefore more stringent, while also accommodating NPCC's generation resource mix, because it requires compensatory load shedding by existing non-nuclear units, but not existing nuclear units, to make up for the loss of generation due to early tripping of the generators.[18]

14. While we propose to approve regional Reliability Standard PRC-006-NPCC-1, the Commission seeks comment on: (1) the technical basis for the 57.8 Hz maximum tripping limit for existing nuclear units established in Requirement R19; and (2) the time-frames for actions that result in changes to the NPCC UFLS program.

15. First, Requirement R19 of the proposed regional Reliability Standard for existing nuclear generating plants provides that:

> R19 Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]
>
> 19.1 Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design licensing limitations but not greater than 57.8Hz.
>
> 19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1

[17] Attachment B to proposed regional Reliability Standard PRC-006-NPCC-1 establishes the compensatory load shedding criteria for the portion of NPCC located in the United States for existing non-nuclear units.

[18] *Compare* proposed regional Reliability Standard PRC-006-NPCC-1, Requirement R16, *with* proposed regional Reliability Standard PRC-006-NPCC-1, Requirement R19.

Hz.

19.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

16. The NERC petition does not explain the technical basis for establishing 57.8 Hz as the maximum frequency at which existing nuclear units may trip pursuant to Requirement R19.1. The NERC petition states that the proposed regional Reliability Standard was based on the work of an NPCC working group.[19] However, the NERC petition and its attachments do not provide any information as to how the 57.8 Hz figure was developed. We seek comment from NPCC, NERC, and other interested entities explaining the technical basis for the 57.8 Hz limit established in Requirement R19.1.

17. Second, Requirement R3 of NERC's Reliability Standard PRC-006-1 requires the planning coordinator to set the schedule for the distribution providers and transmission owners to implement the UFLS program. The regional Reliability Standard PRC-006-NPCC-1, Requirements R5, R16.2, and R19.3, require distribution providers, transmission owners, and generator owners to provide, inform, and transmit exceptions to the UFLS program and justifications for the exceptions to the planning coordinator. The requirements, however, do not specify a time-frame for the completion of these actions. Requirements R5, R16.2, and R19.3 address actions that can result in changes to the UFLS program and should occur before the UFLS program is implemented, thus making it necessary for entities to provide the required information to the planning coordinator

[19] NERC Petition at 11.

within a specified period of time. We note there are other requirements in the proposed regional Reliability Standard that also require actions of distribution providers, transmission owners, and generator owners that should occur before the UFLS program is implemented that include specific time-frames.[20] The Commission seeks comment on whether Requirements R5, R16.2, and R19.3 should also specify time-frames for completion of the required actions and, if so, the appropriate time-frames for each.

B. Violation Risk Factors and Violation Severity Levels

18. NERC states that each Requirement of the proposed regional Reliability Standard PRC-006-NPCC-1 includes one VRF and one VSL and that the ranges of penalties for violations will be based on the sanctions table and supporting penalty determination process described in the Commission-approved NERC Sanctions Guideline. The Commission proposes to approve the VRFs and VSLs for regional Reliability Standard PRC-006-NPCC-1 proposed by NERC as consistent with the Commission's established guidelines.[21]

C. Implementation Plan and Effective Dates

19. NERC proposes that Requirements R1 through R7 become effective on the first day of the first calendar quarter following applicable regulatory approval but no earlier than January 1, 2016 while Requirements R8 through R23 become effective the first day of the first calendar quarter two years following applicable regulatory approval. NERC

[20] *See, e.g.*, Requirements R11, R14, and R23 of proposed regional Reliability Standard PRC-006-NPCC-1.

[21] *North American Electric Reliability Corp.*, 135 FERC ¶ 61,166 (2011).

states that the implementation plan provides that "this standard is based, in part, on the timelines reflected in the existing and ongoing Implementation Plan for NPCC Directory #12 absent the annual milestones required by Directory #12."[22] The Commission proposes to accept the implementation plan and effective dates proposed by NERC for regional Reliability Standard PRC-006-NPCC-1.

III. Information Collection Statement

20. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[23] Upon approval of a collection(s) of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

21. The Commission is submitting these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of the PRA. Comments are solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of the provided burden estimate, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

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[22] NERC August 3, 2012 Errata at 29 of PDF electronic file.

[23] 5 C.F.R. § 1320.11.

22. This Notice of Proposed Rulemaking proposes to approve regional Reliability Standard PRC-006-NPCC-1. This is the first time NERC has requested Commission approval of the proposed regional Reliability Standard. NERC states in its petition that UFLS requirements have been in place at a continent-wide level and within NPCC for many years prior to implementation of the Commission-approved Reliability Standards in 2007. Because the UFLS requirements have been in place prior to the development of PRC-006-NPCC-1, the proposed regional Reliability Standard is largely associated with requirements that applicable entities are already following.[24] The proposed regional Reliability Standard PRC-006-NPCC-1 is designed to work in conjunction with and augment the NERC continent-wide UFLS Reliability Standard PRC-006-1 by mitigating the consequences of underfrequency events, while accommodating differences in system transmission and distribution topology among NPCC planning coordinators due to historical design criteria, makeup of load demands, and generation resources. The proposed regional Reliability Standard is only applicable to generator owners, planning coordinators, distribution providers, and transmission owners in the NPCC Region. The reporting requirements in proposed regional Reliability Standard PRC-006-NPCC-1 only pertain to entities within the NPCC Region.

[24] *See* 5 C.F.R. § 1320.3(b)(2) ("The time, effort, and financial resources necessary to comply with a collection of information that would be incurred by persons in the normal course of their activities (e.g., in compiling and maintaining business records) will be excluded from the 'burden' if the agency demonstrates that the reporting, recordkeeping, or disclosure activities needed to comply are usual and customary.").

23. Public Reporting Burden: Our estimate below regarding the number of respondents is based on the NERC Compliance Registry as of July 24, 2012. According to the NERC Compliance Registry, there are 2 planning coordinators and 135 generator owners within the United States portion of the NPCC Region. The Commission bases individual burden estimates on the time needed for planning coordinators to incrementally gather data, run studies, and analyze study results to design or update the UFLS programs that are required in the regional Reliability Standard in addition to the requirements of the NERC Reliability Standard PRC-006-1.[25] Additionally, generator owners must set each underfrequency trip relay below the appropriate generator underfrequency trip protection settings threshold curve in PRC-006-NPCC-1, Figure 1 and provide the generator underfrequency trip setting and time delay to its planning coordinator within 45 days of the planning coordinator's request. These burden estimates are consistent with estimates for similar tasks in other Commission-approved Reliability Standards. The following estimates relate to the requirements for this Notice of Proposed Rulemaking in Docket No. RM12-12-000 (For Planning Coordinators) and are in addition to the burden for the continent-wide Reliability Standard PRC-006-1, which was approved in Order No. 763 (approved by OMB Control No.1902-0244 on7/9/2012).

[25] The burden estimates for Reliability Standard PRC-006-1 are included in Order No. 763 and are not repeated here.

PRC-006-NPCC-1 (FERC-725L) (Automatic Underfrequency Load Shedding)[26]	Number of Respondents Annually (1)	Number of Responses per Respondent (2)	Average Burden Hours Per Response (3)	Total Annual Burden Hours (1)x(2)x(3)
PCs*: Design and document Automatic UFLS Program	2	1	8	16
PCs: Update and Maintain UFLS Program Database			16	32
GOs*: Provide Documentation and Data to the Planning Coordinator	135	1	16	2160
GOs: Record Retention			4	540
Total				2748

*PC=planning coordinator; GO=generator owner

Total Annual Hours for Collection: (Compliance/Documentation) = 2,748 hours.

Total Reporting Cost for planning coordinators: = 48 hours @ $120/hour = $5,760.

Total Reporting Cost for generator owners: = 2,160 hours @ $120/hour = $259,200.

Total Record Retention Cost for generator owners: 540 hours @ $28/hour = $15,120.

Total Annual Cost (Reporting + Record Retention)[27]: = $5760 + $259,200 +$15,120 = $280,080.

Title: Mandatory Reliability Standards for the NPCC Region

[26] Proposed regional Reliability Standard PRC-006-NPCC-1 applies to planning coordinators, transmission owners, distribution providers and generator owners. However, the burden associated with the transmission owners and distribution providers is not included within this table because the Commission accounted for it under Commission-approved Reliability Standards PRC-006-1, PRC-007-0 and PRC-009-0.

[27] The Commission bases the hourly reporting cost on the cost of an engineer to implement the requirements of the rule. The record retention cost comes from Commission staff research on record retention requirements.

Action: Proposed Collection FERC-725L.

OMB Control No.: To be determined.

Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

Frequency of Responses: On Occasion.

Necessity of the Information: This proposed rule proposes to approve the regional Reliability Standard pertaining to automatic underfrequency load shedding. The proposed regional Reliability Standard helps ensure the development of an effective UFLS program that preserves the security and integrity of the Bulk-Power System during declining system frequency events in coordination with the continent-wide Reliability Standard PRC-006-1 requirements.

Internal Review: The Commission reviewed the proposed regional Reliability Standard and made a determination that its action is necessary to implement section 215 of the FPA. These requirements, if accepted, should conform to the Commission's expectation for UFLS programs as well as procedures within the NPCC Region.

24. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

25. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory

Commission, phone: (202) 395-4638, fax: (202) 395-7285]. For security reasons, comments to OMB should be submitted by e-mail to: oira_submission@omb.eop.gov. Comments submitted to OMB should include FERC-725L and Docket Number RM12-12-000.

IV. Environmental Analysis

26. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[28] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[29] The actions proposed here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act Certification

27. The Regulatory Flexibility Act of 1980 (RFA)[30] generally requires a description and analysis of any rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business

[28] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

[29] 18 C.F.R. § 380.4(a)(2)(ii).

[30] 5 U.S.C. 601-612.

Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[31] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[32]

28. Proposed regional Reliability Standard PRC-006-NPCC-1 proposes to achieve a coordinated, comprehensive UFLS region-wide consistent program within the NPCC Region to achieve and facilitate the broader program characteristics contained in the requirements of the continent-wide Reliability Standard PRC-006-1.[33] It will be applicable to planning coordinators, generator owners, transmission owners and distribution providers. Comparison of the NERC Compliance Registry with data submitted to the Energy Information Administration on Form EIA-861 indicates that 5 small entities are registered as generator owners in the United States portion of the NPCC Region.[34] The Commission estimates that the small generator owners to whom the proposed regional Reliability Standard applies will incur compliance and record keeping costs of $10,160 ($2,032 per generator owner). Accordingly, proposed regional

[31] 13 C.F.R. 121.101.

[32] 13 C.F.R. 121.201, Sector 22, Utilities & n.1.

[33] NERC Petition at 29-30

[34] The two planning coordinators in the United States portion of the NPCC Region are not considered small entities.

Reliability Standard PRC-006-NPCC-1 should not impose a significant operating cost increase or decrease on the affected small entities.

29. Further, NERC explains that the cost for smaller entities to implement regional Reliability Standard PRC-006-NPCC-1 was considered during the development process. NERC states that proposed regional Reliability Standard PRC-006-NPCC-1 provides an opportunity for smaller entities to aggregate their load with other such entities in the same electrical island. This allows each smaller entity's respective planning coordinator to achieve the desired aggregate outcome within that island according to program characteristics.[35]

30. Based on this understanding, the Commission certifies that the regional Reliability Standard will not have a significant economic impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

VI. Comment Procedures

31. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [INSERT DATE 60 days after publication in the **FEDERAL REGISTER**]]. Comments must refer to Docket No. RM12-12-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

[35] NERC Petition at 25.

32. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

33. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426.

34. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

35. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

36. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and

Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

37. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

REGIONAL RELIABILITY STANDARD PRC-006-SERC-01 – AUTOMATIC UNDERFREQUENCY LOAD SHEDDING	**)** **)** **)**	**Docket No. RM12-9-000**

FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN SUPPORT OF THE SERC RELIABILITY CORPORATION RESPONSE TO THE NOTICE OF PROPOSED RULEMAKING ON REGIONAL RELIABILITY STANDARD PRC-006-SERC-01

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September 24, 2012

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] submits this filing in support of the response of the SERC Reliability Corporation ("SERC") to the Notice of Proposed Rulemaking, issued on July 19, 2012, proposing to approve regional Reliability Standard PRC-006-SERC-01 - Automatic Underfrequency Load Shedding Requirements ("NOPR").

By this filing, NERC expresses its support for the response of SERC to the NOPR and requests that the Commission approve the standard consistent with this filing.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:

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[1] The Federal Energy Regulatory Commission ("FERC" or "Commission") certified NERC as the electric reliability organization ("ERO") in its order issued on July 20, 2006 in Docket No. RR06-1-000. *North American Reliability Corporation*, "Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing," 116 FERC ¶ 61,062 (July 20, 2006).

III. DISCUSSION

On February 1, 2012, NERC submitted a petition seeking approval of regional Reliability Standard PRC-006-SERC-01– Automatic Underfrequency Load Shedding Requirements ("NERC Petition").[2] On July 19, 2012, the Commission issued a NOPR[3] proposing to approve regional Reliability Standard PRC-006-SERC-01, but expressed concerns about a possible inconsistency between PRC-006-SERC-01 and the continent-wide PRC-006-1 — Automatic Underfrequency Load Shedding.[4]

On August 9, 2012, NERC submitted a compliance filing to Order No. 763, which addressed the Commission's concern regarding PRC-006-SERC-01 and PRC-006-1:

> NERC hereby clarifies that the continent-wide standard PRC-006-1 is not replaced by PRC-SERC-006-01. UFLS entities in the SERC Reliability Corporation Region must be compliant with both standards… In any event, UFLS entities must meet the schedule set by the Planning Coordinator to comply with PRC-006-1, Requirement R9, but the timeframe must not exceed 18 months in the SERC Reliability Corporation Region to comply with PRC-SERC-006-01, Requirement R6.

In its NOPR comments, SERC states that it does not oppose the above clarification by NERC, and SERC proposes to revise the rationale for Requirement R6 of PRC-SERC-006-01 as follows:

> The SDT believes it is necessary to put a requirement on how quickly changes to the scheme should be implemented. This requirement specifies that changes must be implemented within 18 months of notification by the PC. The 18 month interval was chosen to give a reasonable amount of time for making changes in the field. All of the SERC Region has existing UFLS schemes which, based on periodic simulations, have provided reliable

[2] Petition of the North American Electric Reliability Corporation for Approval of Regional Reliability Standard PRC-006-SERC-01, Docket No. RM12-9-000 (February 1, 2012).

[3] Notice of Proposed Rulemaking, *Regional Reliability Standard PRC-006-SERC-01 —Automatic Underfrequency Load Shedding Requirements*, 140 FERC ¶ 61,056, (2012).

[4] On May 7, 2012, the Commission issued Order No. 763 approving the continent-wide Reliability Standard PRC-006-1. *See Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, 139 FERC ¶ 61,098 (2012).

> protection for years. Events which result in islanding and an activation of the UFLS schemes are extremely rare *in SERC*. Therefore, the SDT does not believe that changes to an existing UFLS scheme will be needed in less than 18 months. However, if a PC determines there is a need for changing the UFLS scheme faster than 18 months, then the PC may require the implementation to be done sooner as allowed by NERC Reliability Standard PRC-006-1.

SERC also does not oppose modifying the VRF assigned to Requirement R6 of PRC-SERC-006-01 from "medium" to "high".

NERC supports the rationale for Requirement R6 of PRC-SERC-006-01, as revised by SERC, and modifying the VRF assignment to Requirement R6 of PRC-SERC-006-01 from "medium" to "high".

IV. CONCLUSION

NERC respectfully requests that the Commission approve the standard as proposed in the NOPR and consistent with this filing, as mandatory and enforceable.

Respectfully submitted,

/s/ Willie L. Phillips

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 24th day of September, 2012.

/s/ Willie L. Phillips
Willie L. Phillips
Attorney for North American Electric Reliability Corporation

Commissioner John R. Norris Statement
October 18, 2012
Docket Nos. RM12-22-000 and RM12-4-000
Item Nos. E-2 and E-3

Proposed Enhancements to Reliability of Bulk Power System

"These two reliability orders address two distinctly different challenges, and represent two different approaches to maintaining reliability. E-3, concerning Reliability Standard FAC-003-2 on Transmission Vegetation Management (FAC-003), to me is about executing the fundamentals necessary to keep the lights on. We know that, without continuous care of transmission rights of way, vegetation growth will, without question, grow into power lines and impact reliability. This second version of FAC-003 recognizes the inevitability of outages if vegetation management is not in a continual state of maintenance, and also recognizes that this maintenance must be preformed on all transmission facilities that have an impact on reliability. The inclusion of Interconnection Operating Limit (IROL) elements and Major Western Electricity Coordinating Council (WECC) Transfer Path elements is a good step in recognizing that the applicability of FAC-003 should include sub-200 kV facilities that are critical to grid reliability.

"The threat of geomagnetic disturbances (GMD) addressed in the proposed rule in E-2 is a different but equally important reliability challenge. A poster child for a Low Frequency–High Impact threat, GMD involves a judgment call that requires us to assess the likelihood of occurrence, how severe the impact could be, and the options to guard against that impact. Like a cyber attack, the potential size and duration of an outage that could result from a GMD demands that we take the precautions necessary to prevent, limit, or contain the potential impact. While I do not believe there is a reasonable option that will guarantee that GMDs will never impact the grid, there are shorter and longer-term steps that we can take to guard against their potential impacts. Recognizing that taking these steps will come with costs, we have to find a "sweet spot", if you will, where the cost of implementing reasonable reliability measures to guard against GMD impacts is appropriately balanced against the potential costs of a GMD event.

"Given the magnitude of the potential damage, I believe we are taking the right approach in this order by proposing to require that in stage two, there must be more extensive standards developed than just those that address operational and enhanced training procedures (the subject of stage one). The evidence before us today suggests that some or all vulnerable elements of the system will need further hardening to withstand a GMD. I think we appropriately give deference to NERC to make a needs assessment and design the additional measures necessary (through the development of the stage two standards) to meet the reliability needs identified in those assessments. But, as the proposed rule indicates, timing is of the essence. With the prediction of high solar flare activity on the very near time horizon, NERC will need to develop standards and industry to implement them much more rapidly than has previously been required. Again, this is another judgment call where we must decide what is reasonable and what is necessary. I ask NERC and the industry to accept this challenge and work as expeditiously as possible to meet it.

"In summary I think we have approached vegetation management like you would approach changing the oil in your car. You know that, if you do not do it, at some point your car will breakdown. And, preparing for GMDs is like buying insurance for you car. You hope that you will never need it - and in fact, you might not - but, it would be irresponsible to not determine what level of coverage you do need and to make the necessary investment to protect yourself and others from the risk and potential severity of an occurrence."

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Updated: October 18, 2012

News Release: October 18, 2012
Docket Nos. RM12-22-000, RM12-4-000
Item Nos. E-2 & E-3

FERC Proposes Enhancements to Reliability of Bulk Power System

The Federal Energy Regulatory Commission (FERC) today took steps to ensure continued reliable operation of the nation's bulk power system by proposing to approve a revised vegetation management standard and to require new standards addressing the impacts of a geomagnetic disturbance (GMD).

GMDs, which result in distortions to the earth's magnetic field, may cause severe problems with grid reliability, including blackouts as well as damage to critical or vulnerable equipment. Although strong disturbances are infrequent, current mandatory reliability standards do not adequately address vulnerabilities.

To address this reliability gap, today's Notice of Proposed Rulemaking (NOPR) proposes to direct the North American Electric Reliability Corporation (NERC), the FERC-approved Electric Reliability Organization, to develop and submit new GMD standards in a two-stage process.

First, within 90 days of the effective date of a final rule in the proceeding, NERC would file one or more standards requiring owners and operators of the bulk power system to develop and implement operational procedures to mitigate GMD effects. That such procedures already are in place in some areas should allow for faster development and implementation of these standards, the NOPR says.

In the second stage, FERC proposes that NERC file, within six months of a final rule, standards that require grid owners and operators to conduct initial and continuing assessments of the potential impacts of GMDs and, based on those assessments, implement strategies to protect the bulk power system, including automatic blocking of geomagnetically induced currents, instituting specification requirements for new equipment, inventory management, or isolating certain equipment that is not cost effective to retrofit. Stage two would be implemented in phases, focusing first on the most critical and vulnerable assets.

The NOPR does not propose specific requirements, but offers guidance regarding the assessments of the grid's vulnerability to GMDs, the mechanisms for protecting critical or vulnerable components and an implementation schedule. FERC seeks comments on all aspects of the proposal.

In a separate NOPR on vegetation management, FERC proposes to approve revisions submitted by NERC that would:

- Expand the applicability of the standard to include lines operated below 200 kilovolts that are part of an Interconnection Reliability Operating Limit or a Major Western Electricity Coordinating Council Transfer Path.
- Set a new minimum annual inspection requirement.
- Incorporate new minimum clearance distances into the text of the standard.

Comments on both proposals are due 60 days after publication in the *Federal Register*.

R-13-2

(30)

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Commissioner Cheryl A. LaFleur Statement
October 18, 2012
Docket Nos. RM12-22-000 and RM12-4-000
Item Nos. E-2 and E-3

Proposed Enhancements to Reliability of Bulk Power System

"Protecting the reliability of the nation's bulk electric system requires both day-to-day blocking and tackling to make sure that the lights stay on, and preparing for emerging issues including high-impact low-frequency events. Today, we are voting out Notices of Proposed Rulemaking that speak to both these components of reliability.

Vegetation Management Standard

"No issue is more central to reliability than timely and effective tree trimming to keep the transmission system operational. Indeed, a tree contact was a key contributing cause of the 2003 blackout that gave rise to this Commission's jurisdiction over reliability.

"I believe the vegetation management standard (FAC-003-2) that we propose to approve today represents an important step forward in addressing this basic reliability issue. In particular, I note that the new standard includes a requirement to maintain a defined Minimum Vegetation Clearing Distance (MVCD) for all transmission lines above 200 kv and lines below 200 KV that are part of an Interconnection Reliability Operating Limit or WECC Transfer Path, and, for the first time, a requirement to annually inspect 100 percent of the lines subject to the standard. These requirements are both clear and concrete.

"The standard we propose to approve today is one of the first results-based standards put forward by NERC. As I understand the concept of a results-based standard, it includes a clearly defined result – avoidance of outages caused by vegetation within a MVCD—on the basis of which to judge compliance with the standard. Because the standard is judged by results, it proposes to give more flexibility to transmission owners about how to meet those results, as long as they are met. This is an important concept, and the successful implementation of this standard may be a model for further results-based standards.

"I also appreciate the commitment by NERC and the industry, working with EPRI, to fund further empirical research on the proposed MVCD, since that is such a critical element of the proposed standard. I recognize that years of hard work went into this proposed standard, and appreciate the efforts of the NERC standards team as well as everyone here at FERC that worked on the standard.

Geomagnetic Disturbances

"The second Notice of Proposed Rulemaking relates to a very different issue, preventing or mitigating damage to the bulk electric system caused by geomagnetic disturbances resulting from solar storms. Solar storms are an acute example of "High Impact Low Frequency" events, which I believe are among the most difficult, but also the most necessary, to address through standards. Just as our society has over the centuries developed standards to protect elements of our infrastructure from high impact low frequency events like earthquakes and fires, I believe we must begin to address the challenge of making our electric grid resilient to geomagnetic disturbances. This is an issue in which I have taken a strong personal interest. As I have observed, the threat of geomagnetic disturbances damaging the power grid sounds like science fiction, but is in fact based on scientific fact. However, while the fact that geomagnetic disturbances can cause substantial harm to the electric grid is undisputed, the way in which that harm would occur is not without controversy. The technical community has debated whether geomagnetic disturbances caused by solar events would cause the bulk electric system to break apart due to excessive reactive power consumption, cause damage to high-voltage transformers and other key elements of the system due to inductive currents, or some combination of the two. Any of these results is unacceptable, and is exactly the

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sort of cascading disturbance to the bulk power system that section 215 of the Federal Power Act requires us to address. I believe that, while continuing to explore the technical issues, we can and should adopt “No Regrets” actions to prevent and mitigate grid damage from geomagnetic disturbances. The Notice of Proposed Rulemaking we are voting on today includes two such No Regrets actions, both of which are consistent with NERC’s assessment report on GmD issued earlier this year.

“First, we would require NERC to develop and propose a standard that requires transmission owners to take operational steps, to prepare for geomagnetic disturbances. This is one of the first actions proposed in NERC’s assessment and action plan. Because we are approaching a periodic solar maximum in 2013, increasing the threat of damaging solar storms, we are proposing to seek fast action on an operational standard.

“Second, we would require NERC to develop and propose a standard that would require transmission owners to undertake an assessment of the most vulnerable elements of the bulk electric system, and propose steps to prevent or mitigate damage to those elements from geomagnetic disturbances. As indicated in the Notice of Proposed Rulemaking, those steps could include installation of automatic blocking in certain vulnerable and critical transformers, requirement of withstand capability in transformers, inventory management strategies, operational plans to address critical elements of the system, and/or other steps that the industry and NERC may propose. Importantly, the proposed rule gives industry and NERC considerable flexibility of how to address this issue, but not the flexibility to ignore it.

“As with any other program to address pieces of the electric grid—and I have lived through quite a few—the appropriate action steps would likely vary based on how critical an asset was, where it was located, when it was scheduled to be replaced, whether it could be protected by islanding or operating protocols, or whether it needed to be retrofitted with protective equipment. Our collective understanding of these options would likely grow once we started the process.

“I know that the challenge of preparing our bulk electric system for geomagnetic disturbances is very complicated, and complicated challenges require complicated solutions. In the past, the electric grid has undergone many large-scale efforts to refurbish or replace electrical equipment to improve reliability, safety or environmental performance. Because of the size, diversity and continuous operation of the electric grid, these efforts are inevitably more complicated and take longer than expected. To me, that argues for getting started sooner rather than later.

“Finally, I believe it is appropriate to tackle this challenge now because the US is facing considerable investment in our transmission grid, driven by a change in power supply and replacement of aging infrastructure. We have a big opportunity to make sure the next generation of transmission equipment is built to withstand geomagnetic disturbances.

“I hope we will receive a broad range of comments on both Notice of Proposed Rulemaking. I would like to thank the FERC teams that worked on these proposed rules, and on the technical conference on GmD last spring on this issue. Thank you.”

Print this page

Updated: October 18, 2012

From:	Kimberly Mielcarek
To:	Kimberly Mielcarek
Subject:	NERC Statement - Response to FERC"s Proposed Rulemaking on Vegetation Management, Geomagnetic Disturbance Standards
Date:	Thursday, October 18, 2012 5:07:56 PM

Statement

Response to FERC's Proposed Rulemaking on Vegetation Management, Geomagnetic Disturbance Standards

Click for Announcement, FERC Announcement
Norris Statement, LaFleur Statement

WASHINGTON, DC -- The Federal Energy Regulatory Commission issued a notice of proposed rulemaking today proposing to approve the North American Electric Reliability Corporation's vegetation management standard (FAC-003-2). In separate action, the FERC proposed to direct NERC to develop standards that address geomagnetic disturbances and their impacts on the grid.

"The proposed approval of the results-based vegetation management standard is an important recognition of NERC's efforts on addressing this issue," said Gerry Cauley, president and chief executive officer at NERC. "The proposed rulemaking on geomagnetic disturbances provides a framework to address the current vulnerability, and to factor in the scientific and engineering analysis necessary to understand this complex issue."

For more information or assistance, please contact Kimberly Mielcarek.

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141 FERC ¶ 61,046
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

Docket No. RM12-4-000

Revisions to Reliability Standard for Transmission Vegetation Management

(Issued October 18, 2012)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: Pursuant to section 215 of the Federal Power Act, the Commission proposes to approve Reliability Standard FAC-003-2 (Transmission Vegetation Management), submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The proposed Reliability Standard would expand the applicability of the standard to include overhead transmission lines that are operated below 200 kV, if they are either an element of an Interconnection Reliability Operating Limit or an element of a Major WECC Transfer Path. In addition, the proposed Reliability Standard incorporates a new minimum annual vegetation inspection requirement, and incorporates new minimum vegetation clearance distances into the text of the standard.

The Commission also proposes to approve the three definitions, the implementation plan and the Violation Severity Levels associated with the proposed Reliability Standard. Finally, the Commission proposes to direct that NERC revise the

Violation Risk Factor for Requirement R2, and approve the remainder of the Violation Risk Factors.

DATES: Comments are due [INSERT DATE 60 days after publication in the **FEDERAL REGISTER**].

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

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SUPPLEMENTARY INFORMATION:

141 FERC ¶ 61,046
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Revisions to Reliability Standard for Transmission Vegetation Management — Docket No. RM12-4-000

NOTICE OF PROPOSED RULEMAKING

(Issued October 18, 2012)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission proposes to approve Reliability Standard FAC-003-2 (Transmission Vegetation Management), submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO). Proposed Reliability Standard FAC-003-2 modifies the currently effective standard, FAC-003-1 (the "Version 1" standard). The proposed modifications, in part, respond to certain Commission directives in Order No. 693, in which the Commission approved currently-effective Reliability Standard FAC-003-1.[2]

2. Proposed Reliability Standard FAC-003-2 has a number of features that make it an improvement over the Version 1 standard. For example, like Version 1, the proposed

[1] 16 U.S.C. § 824o (2006).

[2] *See Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

Reliability Standard would apply to all overhead transmission lines operated at or above 200 kV, but unlike Version 1, it would explicitly apply to any lower voltage overhead transmission line that is either an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.[3] This is a new class of transmission lines not previously required to comply with the Standard. The proposed Reliability Standard would also make explicit a transmission owner's obligation to prevent an encroachment into the minimum vegetation clearance distance (MVCD) for a line subject to the standard, regardless of whether that encroachment results in a sustained outage or fault.[4] Also, for the first time, the proposed Reliability Standard would require transmission owners to annually inspect all transmission lines subject to the standard and to complete 100 percent of their annual vegetation work plan. The proposed Reliability Standard also incorporates the MVCDs into the text of the standard, and does not rely on

[3] NERC defines "IROL" as "[a] System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System." NERC defines "System Operating Limit" as "[t]he value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria." *See* NERC Glossary of Terms Used in Reliability Standards (NERC Glossary) at 26, 48. The Western Electric Coordinating Council maintains a listing of Major WECC Transfer Paths, *available at* http://www.wecc.biz/Standards/Development/WECC-0091/Shared Documents/WECC-0091 Table Major Paths 4-28-08.doc.

[4] *See* Reliability Standard FAC-003-2, Requirements R1 and R2; *see also* Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard FAC-003-2 – Transmission Vegetation Management at 4, 6 (NERC Petition). NERC proposes to define MVCD as "the calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages." *Id.* at 2.

(continued…)

clearance distances from an outside reference, as is the case with the currently-effective Version 1 standard. We believe these beneficial provisions, and others discussed below, support our proposal to approve FAC-003-2.

3. A recurring cause in many blackouts has been vegetation-related outages. In fact one of the initiating causes of the 2003 Northeast blackout was inadequate vegetation management practices that led to tree contact.[5] Further, NERC has identified a focus on preventing non-random equipment outages such as those caused by vegetation as a top priority that will most likely have a positive impact on Bulk-Power System reliability.[6] We also note that industry has made important strides in reducing the instances of vegetation contact.[7] We believe that the revised FAC-003 standard we propose to approve in this rulemaking, together with a continued focus by industry on best practices for vegetation management, will serve to enhance the reliability of the Bulk-Power System. While we propose to approve NERC's use of the Gallet equation to determine the minimum vegetation clearing distances, we believe it is important that NERC develop

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[5] *See* U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations at 18, 57-64 (April 2004) (2003 Blackout Report).

[6] *See* Gerry Cauley written remarks for November 29, 2011 Reliability Technical Conference at 1, 4 and 5 (Docket No. AD12-1-000).

[7] *See, e.g.*, NERC's Second Quarter 2012 Vegetation-Related Transmission Outage Report at 6-7, available at http://www.nerc.com/fileUploads/File/Compliance/2Q2012_Vegetation%20Report_FINAL%20DRAFT.pdf.

empirical evidence that either confirms the MVCD values or gives reason to revisit the Reliability Standard. Accordingly, consistent with the activity that NERC has already initiated, the Commission proposes to direct that NERC conduct or commission testing to obtain empirical data and submit a report to the Commission providing the results of the testing.

4. We also propose to approve the three new or revised definitions associated with the proposed Reliability Standard for inclusion in NERC's Glossary. Specifically, we propose to approve the changes in the definition of "Right-of-Way (ROW)" and "Vegetation Inspection," as well as the addition of the term "Minimum Vegetation Clearance Distance (MVCD)" as defined in NERC's petition. We also propose to approve NERC's implementation plan for FAC-003-2.

5. While we believe that the proposed Reliability Standard will enhance reliability by requiring sub-200 kV transmission lines that are elements of an IROL or Major WECC Transfer Path to comply with its requirements, we seek comment on how NERC will ensure that IROLs are properly designated, as discussed in detail below. In addition, while we agree that a number of the proposed modifications clarify and make more explicit the transmission owner's obligations, we seek comment with regard to the enforceability of certain provisions.

6. We do not believe, however, that NERC has adequately supported the assignment of a "medium" Violation Risk Factor to Requirement R2, which pertains to preventing vegetation encroachments into the MVCD of transmission lines operated at 200 kV and above, but which are *not* part of an IROL or a Major WECC Transfer Path. As discussed

later, system events have originated from non-IROL facilities. Accordingly, as discussed below, we propose to direct that NERC submit a modification, within 60 days of the effective date of the Final Rule, assigning a "high" Violation Risk Factor for violations of Requirement R2.

I. Background

A. Section 215 of the FPA

7. Section 215 of the FPA requires the Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO subject to Commission oversight, or by the Commission independently.[8] Pursuant to the requirements of FPA section 215, the Commission established a process to select and certify an ERO[9] and, subsequently, certified NERC as the ERO.[10]

B. Reliability Standard FAC-003-1

8. Currently-effective Reliability Standard FAC-003-1 is applicable to transmission owners. The requirements of the Version 1 standard apply to (1) all transmission lines

[8] *See* 16 U.S.C. § 824o(e)(3).

[9] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[10] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006) (certifying NERC as the ERO responsible for the development and enforcement of mandatory Reliability Standards), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

operated at 200 kV or above, and (2) lower-voltage lines designated as "critical to the reliability of the electric system" by a Regional Entity.

9. Currently-effective FAC-003-1 contains four requirements. Requirement R1 requires each transmission owner to prepare, and keep current, a transmission vegetation management program (TVMP) that includes, *inter alia*, a Clearance 1 distance to be achieved at the time of vegetation management work, and a Clearance 2 distance to be maintained at all times. The Clearance 2 distance is set by each transmission owner at a level necessary to prevent flashover, but must be no less than the clearance distances established in the Institute of Electric and Electronics Engineers (IEEE) Standard 516-2003 (Guide for Maintenance Methods on Energized Power Lines). The Clearance 1 distances are established by each transmission owner, and the only numerical criterion under the current standard is that the "Clearance 1 distances shall be greater than those defined by Clearance 2."[11] Further, Requirement R1.3 requires that "[a]ll personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties."

10. Requirement R2 of the Version 1 standard requires that each transmission owner develop and implement an "annual plan for vegetation management work," allowing flexibility to adjust to "changing conditions." Pursuant to Requirement R3, transmission

[11] FAC-003-1, R1.2.1.

owners must report quarterly to the relevant Regional Entity "sustained transmission line outages … caused by vegetation." Requirement R4 requires the Regional Entity to report the outage information to NERC.

C. Order No. 693 Discussion Regarding Vegetation Management

11. On March 16, 2007, in Order No. 693, the Commission approved 83 of 107 proposed Reliability Standards pursuant to FPA section 215(d), including currently-effective FAC-003-1.[12] In addition, pursuant to section 215(d)(5) of the FPA, the Commission directed NERC to develop modifications to FAC-003-1 to address certain issues identified by the Commission, discussed below.

12. In the Notice of Proposed Rulemaking (NOPR) that preceded Order No. 693, the Commission proposed two directives requiring modification of NERC's proposed standard pursuant to section 215(d)(5) of the FPA.[13] The first would have directed NERC to develop a minimum vegetation inspection cycle, and the second would have required NERC to remove the standard's general limitation on applicability to transmission lines operated at 200 kV and above.[14] In Order No. 693, the Commission decided not to require either modification at that time, but continued to express its

[12] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 735.

[13] *Mandatory Reliability Standards for the Bulk Power System,* Notice of Proposed Rulemaking, 71 FR 64,770 (Nov. 3, 2006), FERC Stats. & Regs., Proposed Regulations 2004-2007 ¶ 32,608, at P 387 (2006).

[14] *Id.*

concern about the standard's limited applicability and the lack of a minimum vegetation inspection requirement.

13. The Commission instead required NERC to address a modification to the applicability of the standard through its Standards development process, directing NERC to "modify [FAC-003-1] to apply to Bulk-Power System transmission lines that have an impact on reliability as determined by the ERO."[15] In doing so, the Commission stated that it supported the "suggestions by [certain commenters] to limit applicability to lower voltage lines associated with IROL" and noted that "these suggestions should be part of the input to the Reliability Standards development process."[16] Finally, in response to concerns raised about the cost of compliance with the standard, the Commission explained that the ERO must "develop an acceptable definition that covers facilities that impact reliability but balances extending the applicability of this standard against unreasonably increasing the burden on transmission owners."[17]

14. Similarly, while the Commission decided not to require NERC to submit a modification to FAC-003-1 to incorporate a minimum vegetation inspection cycle as part of Order No. 693, the Commission noted that it "continues to be concerned with leaving

[15] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 706.

[16] *Id.*

[17] *Id.* P 708.

complete discretion to the transmission owners in determining inspection cycles.[18] The Commission also rejected the notion that incorporating such a minimum requirement would lead to a "lowest common denominator" and thereby potentially reduce the frequency of inspections for transmission owners with aggressive inspection cycles.[19] Although the Commission did not require a minimum inspection requirement as part of the standard, it directed NERC "to develop compliance audit procedures to identify appropriate inspection cycles based on local factors."[20]

15. With respect to minimum vegetation clearances distances, the Commission approved FAC-003-1's general approach and "reaffirm[ed] its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions."[21] However, the Commission directed NERC to "develop a Reliability Standard that defines the minimum clearance needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal and non-federal land"[22] and "decline[d] to endorse the use of IEEE 516 as the only minimum clearance."[23]

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[18] *Id.* P 721.

[19] *Id.* P 720.

[20] *Id.* P 735.

[21] *Id.* P 729.

[22] *Id.* P 732.

[23] *Id.* P 731.

16. Finally, the Commission directed NERC to address certain commenters' suggestion that, for purposes of the FAC-003 Reliability Standard, rights-of-way should be defined to encompass the required clearance area, and not the entire legal right-of-way, particularly where the legal right-of-way may greatly exceed the area needed for effective vegetation management.[24]

II. NERC Petition and Proposed Reliability Standard FAC-003-2

A. NERC Petition

17. In its petition, NERC maintains that proposed Reliability Standard FAC-003-2 is just and reasonable, as the proposal meets or exceeds each of the criteria the Commission has identified for evaluating a proposed Reliability Standard.[25] NERC asserts that the proposed Reliability Standard "achieves the specific reliability goal of maintaining a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission ROW and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading."[26] Moreover, NERC maintains that the proposed Reliability Standard contains a technically sound method to achieve that goal, as it requires transmission owners to prevent vegetation from encroaching into the flashover distances, requires consideration of conductor movement and growth rates (among other

[24] *Id.* P 734.

[25] *See* NERC Petition at 44.

[26] *Id.* at 45.

things), requires annual inspections, and requires completion of annual work needed to prevent encroachments. NERC asserts that FAC-003-2 is clear and unambiguous as to the requirements and penalties, and contains clear and objective measures for compliance.[27]

18. Further, NERC maintains that proposed Reliability Standard FAC-003-2 represents an improvement over the currently-effective standard, as FAC-003-2 enhances reliability, facilitates enforceability, and preserves necessary flexibility for transmission owners to address local vegetation conditions.[28] NERC asserts that the proposed Reliability Standard was developed with the shortcomings of the currently-effective standard, as identified in Order No. 693, in mind, including the directive to develop a standard that defines the minimum clearance needed to avoid sustained vegetation-related outages without relying on IEEE-516 to set these clearances.[29] NERC states that the Standard Drafting Team (SDT) considered four potential methods for deriving flashover distances for various voltages and altitudes, and of those, selected the "Gallet equation" because the "information to support the development of the standard was readily available in an industry recognized reference."[30] NERC asserts that the "distances

[27] *Id.* at 46-48; *see also id.* at 33-40.

[28] *Id.* at 3, 44-52.

[29] *See id.* at 5 (citing Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 731-732).

[30] *Id.*, *see also* Ex. I, Appx. 1.

derived using the Gallet Equation result in the probability of flashover in the range of 10^{-6}" (one in a million).[31]

19. NERC states that proposed FAC-003-2 continues to give transmission owners the necessary discretion to determine how to achieve the required clearances,[32] but is more stringent than the currently effective standard because it "explicitly treat[s] any encroachment into the MVCD (without contact, with a flashover, with a momentary

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[31] NERC Petition at 6. As NERC explained in its response to Question 1 of the Commission's Data Requests:

> The probability of a flashover, given a drop in voltage to 85% of the 'Critical Flashover Voltage (CFO),' is roughly .135% (or approximately 10^{-3}). This value represents the probability of a flashover, assuming the specified CFO is achieved or exceeded.
>
> However, this is not the only event being considered when attempting to model the probability of a vegetation flashover. The probability of achieving a maximum switching overvoltage ("Peak Voltage") in excess of the CFO must also be considered. This is shown on page 40 in equation 6 of the Technical Reference Document, and is specified there as roughly 0.135% (also approximately 10^{-3}).
>
> In other words, the conditional probability of flashover given that the 85% CFO has been exceeded is approximately 10^{-3}. However, the probability of the CFO being exceeded is *also* 10^{-3}. As these can be treated as two independent events, the probability is statistically "joint" (the probability of exceeding the CFO and the probability of a flashover given the exceeding of the CFO are independent events). Accordingly, the two probabilities are to be multiplied, yielding a probability on the order of magnitude of approximately 10^{-6}.

[32] NERC Petition at 6, 19-22.

outage, or with a sustained outage) as a violation of the standard."[33] According to NERC, the proposed Reliability Standard incorporates a new requirement to perform an annual inspection of all applicable lines and is "much more explicit regarding what actions must be taken to support vegetation management and reliability."[34]

20. NERC states that proposed FAC-003-2 was designed to address directives from Order No. 693, including the directives requiring that NERC address proposed modifications to expand the applicability of FAC-003-1, evaluate and consider specific proposals made by parties commenting on FAC-003-1, develop compliance audit procedures to identify appropriate inspection cycles, define the minimum clearances needed to avoid sustained vegetation-related outages applicable to transmission lines crossing both federal and non-federal land, and address suggestions that rights-of-way should be defined to encompass required clearance areas only. NERC also explains that proposed FAC-003-2 is one of the first Reliability Standards developed using NERC's "results-based" approach and, therefore, includes some restructuring of the standard to focus on completing objectives and achieving goals, as well as to ensure that enforcement is undertaken in a consistent and non-preferential manner.[35]

[33] *Id.* at 6.

[34] *Id.*

[35] *Id.* at 7.

21. NERC proposes an implementation plan for FAC-003-2.[36] For individual transmission lines that become subject to the vegetation management standard for the first time following designation as an element of an IROL or Major WECC Transfer Path, NERC asks that the requirements become effective the latter of (1) twelve months after the date of such designation, or (2) January 1 of the planning year when the line is forecast to become an element of an IROL or Major WECC Transfer Path.[37]

22. Accordingly, NERC requests that the Commission approve proposed FAC-003-2 and the associated Violation Risk Factors and Violation Severity Levels. NERC requests as an effective date for the Reliability Standard, "the first day of the first calendar quarter that is twelve months following the effective date of a Final Rule in this docket."[38] NERC further requests: (1) retirement of the Version 1 standard concurrent with the effective date of FAC-003-2; (2) approval of three definitions for inclusion in the NERC Glossary; and (3) approval of the implementation plan for proposed FAC-003-2.

B. Proposed Reliability Standard FAC-003-2 and NERC Explanation of Provisions

23. The proposed Reliability Standard includes seven requirements.

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[36] *Id.* at Ex. B.

[37] In considering this aspect of the proposed implementation plan, we assume that NERC asks that the proposed standard become effective on the "later" of alternative (1) or (2), rather than the "latter."

[38] *Id.* at 68.

24. **Requirements R1 and R2**: Pursuant to Requirements R1 and R2, transmission owners must "manage vegetation to prevent encroachments into the MVCD of its applicable line(s)," and any encroachment is considered a violation of these requirements regardless of whether it results in a sustained outage.[39] NERC characterizes this as a "zero tolerance" approach to vegetation management.[40] Further, NERC maintains that these requirements represent an improvement over the currently effective Version 1 Standard because the proposed standard makes the requirement to prevent encroachments explicit, and because it incorporates specific clearance distances into the standard itself based on "an established method for calculating the flashover distance for various voltages, altitudes, and atmospheric conditions."[41]

25. NERC has bifurcated the basic requirement to prevent encroachment into the MVCDs. Requirement R1 applies to IROL elements and Major WECC Transfer Path elements and is assigned a high Violation Risk Factor. Requirement R2 sets forth the same substantive requirements but pertains to non-IROL and non-Major WECC Transfer Path elements and is assigned a medium Violation Risk Factor. NERC explains that it

[39] *See* Reliability Standard FAC-003-2, Requirements R1 and R2, subsection 1 (transmission owners must manage vegetation to prevent, *inter alia*, "an encroachment into the MVCD, as shown in FAC-003-Table 2, observed in Real-Time, absent a Sustained Outage").

[40] NERC Petition at 6.

[41] *Id.* at 22.

bifurcated the requirement to "eliminate commingling of higher risk reliability objectives and lesser risk reliability objectives."[42]

26. In addition, NERC has included a footnote describing certain conditions or scenarios, outside the transmission owner's control, where an encroachment would be exempt from Requirements R1 and R2, including natural disasters and certain human or animal activity.[43] As NERC explains, the footnote "does not exempt the Transmission Owner from responsibility for encroachments caused by activities performed by their own employees or contractors, but it does exempt them from responsibility when other human activities, animal activities, or other environmental conditions outside their control lead to an encroachment that otherwise would not have occurred."[44]

27. **Requirement R3:** Requirement R3 requires a transmission owner to have "documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines." Requirement R3 requires that these strategies take into account movement of conductors (sag and sway), and the inter-relationship between vegetation growth rates, vegetation control methods, and inspection frequency. While NERC acknowledges that this requirement does not include the currently effective standard's requirement to establish a

[42] *Id.* at 22-23.

[43] *See* proposed Reliability Standard FAC-003-2, n.2.

[44] NERC Petition at 23.

Clearance 1 as part of the required TVMP, NERC notes that Clearance 1 levels are currently left largely to the discretion of the transmission owner and that the only numerical criterion for Clearance 1 is that it "must be some undefined amount larger than the minimum flashover distance [Clearance 2]."[45] NERC maintains that the proposed standard's requirement to avoid encroachments after taking into account conductor movement, vegetation growth rates, etc., "still retains the same obligations defined by 'Clearance 1.'"[46]

28. **Requirement R4:** Requirement R4 requires a transmission owner that has observed a vegetation condition likely to produce a fault to notify, "without any intentional time delay," the appropriate control center with switching authority for that transmission line. NERC states that the proposed requirement is an improvement over the Version 1 standard, in that it makes explicit the obligation to communicate imminent threats, rather than merely establish and document a process for doing so, as is currently required.[47] In addition, NERC explains that the currently-effective Reliability Standard's requirement that the process allow for "immediate" notification was "impractical at best," and was therefore replaced with the phrase "without any intentional time delay," which still requires timely notification.

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[45] *Id.* at 20.

[46] *Id.*

[47] *See id.* at 25-26 (referencing Requirement R1.5 of FAC-003-1).

29. **Requirement R5:** Requirement R5 requires a transmission owner constrained from performing vegetation management work needed to prevent a vegetation encroachment into the MVCD prior to implementation of the next annual work plan to take corrective action to prevent such encroachments. NERC contends that this proposed requirement represents an improvement over the currently-effective provision, Requirement R1.4, which merely requires the transmission owner to develop mitigation measures to address such circumstances, but does not affirmatively require the transmission owner to take corrective action. The proposed measures for determining compliance associated with proposed Requirement R5 provide examples of the kinds of corrective actions expected, including increased monitoring, line de-ratings, and revised work orders.[48]

30. **Requirement R6**: Pursuant to Requirement R6, each transmission owner shall inspect 100 percent of its applicable lines at least once per year and with no more than 18 months between inspections on the same Right-of-Way. NERC maintains that the new requirement is "an improvement to the standard that reduces risks," and notes that the currently effective standard allows the transmission owner to develop its own schedule for inspections (with no standard minimum time) and contains no explicit requirement that the transmission owner meet its established schedule.[49]

[48] *See id.* at 24-25.

[49] *Id.* at 17-18.

31. **Requirement R7:** Pursuant to Requirement R7, the transmission owner must complete 100 percent of its annual vegetation work plan, allowing for documented changes to the work plan as long as those modifications do not allow encroachment into the MVCD. NERC argues that this requirement represents an improvement over the currently effective standard because the current Requirement (R2) "does not mandate that entities plan to prevent encroachments into the MVCD, but simply that they implement whatever is included in the plan."[50]

32. NERC explains in its petition that certain requirements in the currently-effective Reliability Standard have not been translated into a requirement in the proposed standard. In particular, NERC notes that the Version 1 standard's reporting requirements, R3 and R4, have been moved into the compliance section of proposed standard FAC-003-2.[51] NERC maintains that the reporting requirement remains enforceable under NERC's Rules of Procedure, which gives NERC authority, *inter alia*, to require entities to provide "such information as is necessary to monitor compliance with the reliability standards."[52] NERC further notes that it can take action against any entity that fails to comply with such a reporting requirement (which would amount to a failure to comply with a NERC Rule of Procedure) pursuant to NERC Rule of Procedure Section 100, and that it is

[50] *Id.* at 28.

[51] *Id.* at 29-31.

[52] *Id.* at 31 (quoting NERC Rule of Procedure Section 400.3). This provision actually is located at Section 401.3.

obligated to notify the applicable governmental authorities of the entity's failure to comply.[53]

33. In addition, NERC acknowledges that the proposed standard no longer contains a requirement that personnel involved in the design and implementation of a vegetation management program have appropriate qualifications and training (currently set out in sub-requirement R1.3).[54] According to NERC, this provision of the Version 1 standard is "effectively meaningless," since "appropriate" qualifications and training are undefined and left entirely to the discretion of the transmission owner. Thus, NERC maintains that elimination of this sub-requirement does not impact reliability.

34. NERC is also seeking to revise the definitions of Right-of-Way (ROW) and Vegetation Inspection, and to add a new definition for MVCD.[55] NERC proposes that Right-of-Way be defined as the "corridor of land under a transmission line(s) needed to operate the line(s)," which may not exceed the Transmission Owner's legal rights but may be smaller. NERC proposes to modify "Vegetation Inspection" to allow both maintenance inspections and vegetation inspections to be performed concurrently. Finally, NERC proposes a new definition, "MVCD," to be "[t]he calculated minimum

[53] *See id.* at 31-32.

[54] *Id.* at 23-24.

[55] *See* NERC Petition, Ex. C.

distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages."

35. NERC explains in its petition how it will approach enforcement of each Requirement under FAC-003-2, noting that each Requirement has an associated compliance measure that identifies what is required and how the Requirement will be enforced. NERC explains, *inter alia*, that the measures for Requirements R1 and R2 require each transmission owner to have "evidence that it managed vegetation to prevent encroachment into the MVCD," and to be able to produce records "indicating the requirements were not violated."[56] In order to show compliance with Requirement R3, NERC explains that a transmission owner will be "obligated to show documentation, and that documentation must be sufficient to satisfy the auditor that the information contained in that documentation is sufficient that the Transmission Owner can use it to prevent encroachment into the MVCD."[57] Similarly, NERC explains that "entities will not be able to comply with [Requirement R7] without having a documented plan."[58]

36. NERC asserts that it has addressed seven directives in Order No. 693 regarding NERC's vegetation management standard.[59] First, NERC asserts that it has addressed the concerns in applying the vegetation management standard only to transmission lines that

[56] NERC Petition at 34.

[57] *Id.* at 35.

[58] *Id.* at 39.

[59] *See id.* at 40-44.

are 200 kV or above.[60] NERC notes that it has addressed that concern (and related directives) by extending the applicability of the proposed standard to overhead transmission lines that are either 200 kV and above, or less than 200 kV if the line is an element of an IROL or a Major WECC Transfer Path. In addition, NERC explains that it has developed an appropriate implementation plan for any new lines covered by the standard, thereby satisfying the Commission's directive to consider a delayed implementation date if lower-voltage facilities are included.[61] NERC further maintains that it has addressed the Commission's concern about allowing transmission owners full discretion to set inspection schedules by requiring inspections at least once per year, has satisfied the Commission's directive to define minimum clearances for both federal and non-federal lands by adopting MVCDs that apply to lines on both federal and non-federal lands, and has satisfied the Commission's directive to consider whether modifications to the definition of Right-of-Way were necessary through the proposed revision to that definition.[62]

III. PNNL Report and Comments

A. PNNL Report

37. As NERC explains in its petition, the Standard Drafting Team applied the "Gallet equation" to derive the MVCDs set forth in FAC-003-2. NERC describes the Gallet

[60] *Id.* at 40-42.

[61] *Id.* at 42-43.

[62] *Id.* at 43-44.

equation as a "well-known method of computing the required strike distance for proper insulation coordination."[63]

38. The Commission's Office of Electric Reliability retained the Pacific Northwest National Laboratory (PNNL) to undertake an "analysis of the mathematics and documentation of the technical justification behind the application of the Gallet equation and the assumptions used in the technical reference paper [Exh. A of NERC's petition]."[64]

39. PNNL's final *Report on the Applicability of the "Gallet Equation" to the Vegetation Clearances of NERC Reliability Standard FAC-003-2* (PNNL Report) was posted as part of the record in this docket on April 23, 2012, along with a notice inviting comment on the PNNL Report within 30 days.

40. While the PNNL Report points out benefits of the use of the Gallet equation, it raises questions about potential inconsistencies in NERC's filing.[65] The PNNL Report raises concerns about NERC's use of an assumed gap factor of 1.3, asserting that that figure has not been adequately supported for use with vegetation and that there is no

[63] NERC Petition, Ex. I (Technical Reference Document) at 39.

[64] *See* April 23, 2012 Notice Inviting Comments on Report.

[65] PNNL Report at iv-v ("The equation [the Gallet equation] is a good and simple-to-use way to solve a problem made difficult by the nonlinear interactions of the variables. However, in spite of the evident usefulness of the equation, inconsistencies are found in the NERC filing . . . .").

evidence that statistics relating to tower design are usable with vegetation.[66] Instead, the PNNL Report suggests that a "rod-plane gap and tree branch might have about the same gap factor (i.e., k=1),"[67] but does not provide any other indication of an appropriate gap factor for use with vegetation.

41. The PNNL Report further asserts that without NERC's assumption "that the gap between a power line and growing vegetation is stronger (by 30%) than the reference gap used in developing the Gallet equation," the minimum distances calculated would be about 50% larger.[68]

42. The PNNL Report also asserts that "[t]hough there is no obvious way to relate tower clearance to vegetation clearance," the proposed MVCDs in FAC-003-2 are small when compared to transmission tower design clearances:

> The values for tower clearance for a line at 500 kV in the Transmission Line Reference Book range from 8.3 ft. to over 17 ft. The NERC filing requires a gap less than 6 ft for the same voltage, even at high altitude. There is no reason to suppose that a tree could safely be allowed so much closer to a line (less than 6 ft) than a tower.[69]

[66] *See id.* at 11-13, 19.

[67] PNNL Report at 13.

[68] *Id.* at v.

[69] *Id.* at 19.

B. Comments in Response to PNNL Report

43. Nine sets of comments were filed in response to the PNNL Report, with timely submissions made by NERC, the Canadian Electricity Association, American Electric Power (AEP), Duke Energy Corporation (Duke), Oncor Electric Delivery Company LLC (Oncor), Kansas City Power & Light and KCP&L Greater Missouri Operations Company (KCP&L), Arizona Public Service Company (APS), and Salt River Project Agricultural Improvement and Power District (Salt River), as well as a joint submission by the Edison Electric Institute, the American Public Power Association, the National Rural Electric Cooperative Association and the Electric Power Supply Association (collectively, the Trade Associations).

44. In its comments, NERC asserts that the PNNL Report "(a) improperly juxtaposes data included in the FAC-003-2 Reliability Standard; (b) disregards NERC's justification regarding the selection of transient overvoltage calculations; (c) fails to consider joint probability of independent events when analyzing flashover probability; and (d) disagrees with the choice of gap factor for vegetation without providing any empirical evidence, scientific reasoning or expert consensus on what an appropriate gap factor should be."[70]

45. With regard to the assertion in the PNNL Report that there is no evidence that statistics relating to tower design are usable with vegetation, NERC explains the rationale for its use of the Gallet equation in some detail (discussed further in PP 47 - 48 below),

[70] NERC Comments on PNNL Report at 1-2 (NERC Comments).

and notes that the PNNL Report "disagrees with [NERC's] choice of gap factor for vegetation without providing any empirical evidence, scientific reasoning, or expert consensus on what an appropriate gap factor should be."[71] NERC explains that the Standard Drafting Team "relied on the scientific body of available knowledge and the opinions of experts (applied conservatively) currently working in the industry" to support a gap factor of 1.3.[72] By contrast, NERC asserts that "there is no justification for the suggestion that the gap factors for vegetation could be less than unity," and considers the PNNL Report's suggestion of a gap factor of 1.0 to be based "purely on speculation."[73]

46. With regard to PNNL's assertion that "inconsistencies are found in NERC's filing", NERC states that the "inconsistencies" identified by the PNNL Report in NERC's Technical Reference Document result from PNNL erroneously comparing two separate sets of data developed for different purposes. According to NERC, one set of data was developed to demonstrate the consistency between the clearance values set out in the IEEE-516 standard and the values generated using the Gallet equation when using similar assumptions as those used in the IEEE-516 standard. The second set of data was designed to generate appropriate clearance values using the Gallet equation and "a set of assumptions determined by the [SDT] to be consistent with the purposes of the

[71] *Id.* at 2.

[72] *Id.*, Att. A at 8.

[73] *Id.*

standard."[74] NERC responds that PNNL's comparison of the two sets of data is therefore "misleading."[75]

47. With respect to the gap factor, NERC maintains that it relied on a widely known and regarded source for determining the appropriate gap factor, which indicates that an appropriate gap factor for a conductor-to-lateral structure configuration is in the range of 1.25 to 1.40.[76] Specifically, NERC explains that the Standard Drafting Team (SDT) relied on the "widely regarded" *Insulation Coordination for Power Systems,* by Andrew Hileman, to develop the proposed gap factor of 1.3.[77] NERC indicated that there is a range of gap factors that could be used in the Gallet equation, each factor designed to represent the difference in voltage withstand capability[78] between a given object, i.e., the transmission wire or conductor, and a reference case, i.e., the object for which the distance from the wire must be established. The gap factor varies based on the nature of the "gap configuration" of the reference case. In its response to the PNNL Report, NERC

[74] *Id.*, Att. A at 2.

[75] *Id.*

[76] *Id.*, Att. A at 6-7.

[77] *Id.* (citing Andrew Hileman, *Insulation Coordination for Power Systems* 167 (Marcel Dekker, New York, NY 1999)).

[78] The PNNL Report defines "withstand" in this context as "[t]he capability of an insulation system to function as an insulator when a high voltage is applied." PNNL Report at 1.

provided the following table showing the range of gap factors (shown as k_g in the table below) based on the gap configuration:

Typical Value of Gap Factors k_g for Phase-Ground Insulations

Gap Configuration	Range of k_g	Typical value of k_g
Rod-plane	1.00	1.00
Rod-rod (vertical)	1.25 – 1.35	1.30
Rod-rod (horizontal)	1.25 – 1.45	1.35
Conductor-lateral structure	1.25 – 1.40	1.30
Conductor-lower rod	1.40 – 1.60	1.50

48. NERC then states that use of a gap factor of 1.3 is conservative:

> It is worth noting that the gap factors for many shapes that could approximate vegetation are even higher than the 1.3 used in FAC-003-2, with ranges that include values as high as 1.6. Hileman notes that in regards to the substation environment (which includes many objects, conducting and non-conducting, with varying shapes and configurations): "Practically, the lowest gap factor in the substations is 1.3, which normally is conservative."
>
> . . .
>
> [T]he [SDT] did not rely on any specific properties inherent in trees, rather, the [SDT] conservatively assumed that vegetation had the same properties as metal. The [SDT] elected to use the "typical" value for "conductor to lateral structure." Unlike the other examples given, which specify a "typical" value that is equivalent to the midpoint of the range, this value (1.3) is within the conservative third of the range (1.25 – 1.4).[79]

[79] *Id.* at 7.

49. In response to the assertion in the PNNL Report that "[t]here is no reason to suppose that a tree could safely be allowed so much closer to a line . . . than a tower" (see P 42, *supra*), NERC explains in its comments why NERC's proposed MVCDs may not be directly comparable to distances based on tower design:

> [C]are must be taken when making an interpretation of the tabular data, as the original survey participants may have answered the questions in a general context involving multiple structure designs. The final structure design parameters provided in the Red Book include the CFO gap plus other factors (such as insulator geometry, personnel safety and extreme lightning events). Accordingly, they should not be considered the final word with regard to Vegetation Management, as those distances were established to address a number of other issues. FAC-003-2 is not intended to mandate the parameters for all future line designs; it is focused solely on the distances necessary to mitigate the risk of vegetation related outages.

50. In addition to providing a response to the technical issues raised by the PNNL Report, NERC argues that the Commission is obligated under FPA section 215(d)(2) to give due weight to NERC's technical expertise with respect to the content of proposed standards.

51. Trade Associations, Duke, Oncor and other commenters support NERC's technical analysis. AEP and Oncor agree with NERC that the PNNL report contains inappropriate comparisons of data NERC presented in its petition and supporting materials, and that if NERC's Gallet-generated numbers are compared to the distances calculated under IEEE-516, the "clearances determined by the two calculations are in fact

closely aligned."[80] AEP and Oncor further maintain that the PNNL Report does not offer a "better alternative" to the use of the Gallet equation, and that it does not dispute the Standard Drafting Team's rationale for its selection of transmission overvoltages.[81] AEP and Oncor note that the PNNL Report acknowledges "that the Gallet Equation is 'a fair representation of the performance of an air gap of a few meters, a simple-to-use way to solve a problem made difficult by the nonlinear interactions of the variables' and that NERC has used the complete method that includes all the factors that go into the estimate of peak voltage."[82] AEP and Oncor also assert that proposed FAC-003-2, taken as a whole, will serve to improve the reliability of the system. AEP notes that the MVCDs included in Table 2 of the proposed Reliability Standard are merely the first piece of an overall strategy the transmission owner must develop to manage vegetation, and that the transmission owner must have documented strategies to prevent encroachments within all rated operating conditions, after taking into account sag, sway, and vegetative growth.

52. KCP&L comments that the PNNL Report should have "included discussion regarding a correction factor in the clearance calculation using the Gallet Equation due to the difference in the conductive properties of the metal rod compared to vegetation."[83]

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[80] AEP Comments and Oncor Comments at 2.

[81] *Id.*

[82] *Id.* at 3 (citing PNNL Report at 19).

[83] KCP&L Comments at 2-3.

KCP&L supports use of the Gallet equation as an "improvement over the industry's current means of determining clearance distances."[84]

53. APS questions whether either the Gallet equation or the IEEE standard incorporated in currently-effective FAC-003-1 "provides a demonstrable indicator of the flash-over distance between conductors and ground vegetation . . . ,"[85] and accordingly suggests that the Commission ask the Department of Energy to experimentally verify the distances derived from the IEEE and Gallet methodologies. APS takes the position that, until such data are developed, the Gallet methodology "seems more reasonable" than the IEEE standard as a basis for developing a clearance requirement.[86]

54. Salt River supports the PNNL Report's analysis, noting that it has questioned the applicability of the Gallet equation for vegetation clearances throughout the development of FAC-003-2. Salt River further agrees that there is insufficient evidence to suggest that a tree could safely be allowed much closer to a line than a tower. Finally, Salt River supports the experimental verification of any proposed guidelines regarding required vegetation clearances.

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[84] *Id.* at 3. KCP&L also points out what it characterizes as a technical error in the PNNL Report related to the impact of multiple gaps on flashover probabilities, maintaining that in the example given by the PNNL Report, the flashover probability with 20 gaps should be 4% rather than 33%. *Id.*

[85] APS Comments at 2.

[86] *Id.*

C. NERC Response to Data Request

55. On May 4, 2012, Commission staff issued data requests to NERC. NERC submitted a timely response to the data requests on May 25, 2012, addressing matters such as the correct understanding and enforceability of certain provisions of the proposed Reliability Standard. Relevant elements of NERC's response to the data requests are discussed further below.

IV. Discussion

56. Pursuant to section 215(d) of the FPA, we propose to approve Reliability Standard FAC-003-2, including the associated new and revised definitions and implementation plan, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. As discussed in Section A below, we believe the proposed Reliability Standard will enhance reliability and satisfies a number of the outstanding directives from Order No. 693. In addition, we seek further comment on certain aspects of the proposed Reliability Standard. Accordingly, we discuss the following matters below: (A) proposal to approve FAC-003-2; (B) applicability of the standard to sub-200 kV transmission lines; (C) clearance distances; (D) appropriate Violation Risk Factor for Requirement R2; (E) enforcement issues; (F) inclusion of reporting obligations as a compliance measure; and (G) proposed definitions.

A. The Commission Proposes to Approve FAC-003-2

57. We believe that proposed standard FAC-003-2 is an improvement over the currently-effective Version 1 standard, will support vegetation management practices that can effectively protect against vegetation-related transmission outages, and satisfies a

number of the outstanding directives from Order No. 693. As discussed earlier, NERC has explained how many of the Requirements improve upon the currently-effective Version 1 standard. In support of our proposal to approve FAC-003-2, we highlight several of these improvements. For example, in accordance with our directives in Order No. 693, as discussed further below, NERC has expanded the applicability of the Reliability Standard so that it now applies not only to all transmission lines above 200 kV, but also to transmission lines operated *below* 200 kV if they are an element of an IROL or an element of a Major WECC Transfer Path.

58. In addition, NERC has incorporated minimum clearance distances into the text of the Reliability Standard, and no longer includes a required clearance distance based on distances set by IEEE-516 which, as indicated in Order No. 693, served a different purpose than vegetation management. Proposed FAC-003-2 requires a transmission owner to prevent an encroachment into the MVCD, even if the encroachment does not result in a flashover or fault. As NERC explains, "FAC-003-2 presents a 'zero-tolerance' approach to vegetation management, explicitly treating any encroachment into the MVCD . . . as a violation . . . ."[87] Finally, encroachments must be prevented under all rated operating conditions, and must take into account sag and sway of the line, as well as vegetative growth rates and frequency of inspection and maintenance.

[87] NERC Petition at 6.

59. While the Commission did not require NERC to adopt a minimum inspection cycle as part of Order No. 693, the Commission did express concern both prior to and as part of Order No. 693 that inspection cycles should not be left entirely to the discretion of the transmission owner. Accordingly, in Order No. 693, the Commission stated that:

> The Commission continues to be concerned with leaving complete discretion to the transmission owners in determining inspection cycles, which limits the effectiveness of the Reliability Standard. Accordingly, the Commission directs the ERO to develop compliance audit procedures . . . which would identify appropriate inspection cycles based on local factors. These inspections cycles are to be used in compliance auditing of FAC-003-1 by the ERO or Regional Entity to ensure such inspection cycles and vegetation management requirements are properly met by the responsible entities.[88]

NERC has addressed this concern by incorporating a *minimum* inspection cycle requirement in the proposed Reliability Standard (at least once per calendar year and no more than 18 months between inspections).[89]

60. Thus, based on the overall benefits of proposed FAC-003-2, we propose to approve Reliability Standard FAC-003-2 and propose to direct a change in the VRF level assigned to Requirement R2, as discussed further below.

61. In considering whether to approve Reliability Standard FAC-003-2, we give due weight to NERC's technical expertise. In light of our proposal to approve the proposed

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[88] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 721.

[89] *See* NERC Petition at 43.

Reliability Standard, commenters' suggestions that we have failed to give due weight to NERC's technical expertise are moot. Below, however, we will discuss our substantive consideration of the proposed minimum clearance distances derived based on application of the Gallet equation and certain technical points raised by the PNNL Report and commenters.

B. Applicability

62. The currently-effective Reliability Standard, FAC-003-1, is applicable to any transmission line operated at 200 kV and above, and to any line of lesser voltage designated by a Regional Entity[90] as "critical to the reliability of the electric system in the region."[91] As discussed above, the Commission accepted this approach in Order No. 693, but directed NERC to address a modification to the applicability of the standard through its Reliability Standards development process:

> We will not direct NERC to submit a modification to the general limitation on applicability as proposed in the NOPR. However we will require the ERO to address the proposed modification through its Reliability Standards development process. As explained in the NOPR, the Commission is concerned that the bright-line applicability threshold of 200 kV will exclude a significant number of transmission lines that could impact Bulk-Power System reliability . . . . We support the suggestions by Progress Energy, SERC and MISO to limit applicability to lower voltage lines associated

[90] Reliability Standard FAC-003-1 refers to Regional Reliability Organizations (RROs), the precursors to Regional Entities.

[91] To date, no Regional Entity has designated any lower voltage lines as critical to regional reliability and therefore subject to FAC-003-1.

> with IROL and these suggestions should be part of the input to the Reliability Standards development process.
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> . . . .
>
> [Other commenters] raise concerns about the cost of implementing this Reliability Standard if the applicability is expanded to lower-voltage facilities. We recognize these concerns . . . and we direct the ERO to develop an acceptable definition that covers facilities that impact reliability but balances extending the applicability of this standard against unreasonably increasing the burden on transmission owners.[92]

63. We believe that NERC has satisfied this directive by considering the various concerns raised by the commenters as noted in Order No. 693, and ultimately by revising the Reliability Standard so that it applies to not only to lines that are 200 kV and above, but also to any sub-200 kV transmission line that is an element of an IROL or a Major WECC Transfer Path. We believe that NERC has supported its approach to the expansion in applicability, noting that proposed FAC-003-2 provides specific criteria to determine applicability for sub-200 kV transmission lines. In addition, NERC has used an impact-based approach for determining applicability rather than a bright-line threshold as a means of balancing the potential increased burden on transmission owners under a standard with expanded applicability.[93]

64. While we view the modified applicability as a significant improvement, there are two aspects on which we seek comment. First, section 4.2.2 of proposed FAC-003-2 provides that the standard applies to overhead transmission lines operated below 200 kV

[92] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 706, 708.

[93] NERC Petition at 41-42.

identified as an IROL under NERC Standard FAC-014 by the planning coordinator. However, FAC-014-2 does not explicitly require the planning coordinator to provide information about IROL status to transmission owners. Further, IROLs may change with changing system conditions. Given these factors, we seek a better understanding of how FAC-003-2 will be applied to facilities designated as IROLs. For example, we seek comment on how information regarding IROL status will be transmitted to transmission owners that must comply with FAC-003-2 and how transmission owners can effectively implement vegetation management per FAC-003-2 given that such programs are generally implemented annually and a change in IROL status can take place at any time given changing system conditions.[94]

65. Second, in Order No. 693, the Commission directed that the proposed Reliability Standard apply to "Bulk-Power System transmission lines that have an impact on reliability as determined by the ERO."[95] The Commission noted evidence that some lines below 200 kV can have significant impacts on the Bulk-Power System, including IROLs and System Operating Limits (SOLs).[96] The Commission directed the ERO, however, to balance extending the applicability of the standard against unreasonably increasing the

[94] For example, if a line is designated to be an IROL element by the planning coordinator, how will the transmission owner know to thereafter apply FAC-003-2 to that line? If the designation of an IROL changes with changes in system conditions, how will a transmission owner document management of vegetation over time?

[95] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 706.

[96] *Id.* P 710.

burden on transmission owners.[97] Thus, we seek comment on how the applicability of the proposed Reliability Standard complies with the directive that the standard cover "lines that have an impact on reliability." In addition, since the issuance of Order No. 693, we note that Commission staff and NERC stated in their joint report on the 2011 Southwest outage that failure to properly designate IROLs was a major cause of the outage.[98] Therefore, as part of the broader inquiry into whether the standard covers "lines that have an impact on reliability," we seek comment on how NERC will assure that IROLs are properly designated.

C. Requirements R1 and R2

1. Minimum Clearance Values

66. We find that NERC has relied on a reasonable method for setting the MVCD, and has supported the inputs and assumptions it used to develop those minimum clearance distances, at least until such time that empirical data is developed and is available for use in setting MVCDs. We note that the MVCDs are roughly equivalent to, or slightly larger than, the minimum Clearance 2 distances in the current standard.

67. NERC explains that the MVCD is the result of a conservative gap factor. Further, the MVCD clearances represent only one aspect of proposed FAC-003-2. The MVCD

[97] *Id.* P 708.

[98] *See* FERC and NERC Staff Report, Arizona- Southern California Outages on Sept. 8, 2011: Causes and Recommendations at 6, 97-100 (April 2012).

establishes a "*minimum*[] required to prevent Flash-over."[99] The proposed standard requires transmission operators to manage vegetation to ensure that vegetation does not encroach into that minimum clearance distance, which requires transmission owners to manage vegetation to a distance further than the MVCD. For example, transmission owners are required to have documented compliance strategies, procedures, processes, or specifications under Requirement R3 to prevent encroachments into the MVCDs after taking into account sag and sway of the lines, as well as vegetative growth rates, planned control methods and frequency of inspections. Similarly, under Requirement R7, a transmission owner is required to "complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD."[100] Indeed, as NERC has explained, the "Transmission Owner is obligated to show detailed documentation that clearly explains their system with regard to the geography and how the Transmission Owner will execute the plan to prevent encroachment."[101] Further, NERC has indicated that a transmission owner's documentation approach will generally contain the following elements:

> 1. the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation

[99] NERC Petition, Ex. A (Proposed Reliability Standard FAC-003-2) at 26 (Table 2 – Minimum Vegetation Clearance Distances (MVCD) For Alternating Current Voltages), n. 7 (emphasis added).

[100] Proposed Reliability Standard FAC-003-2 R7.

[101] *See* NERC Response to Data Request Q2.

> height) *to ensure that MVCD clearances are never violated*.
>
> 2. the work methods that the Transmission Owner uses to control vegetation
>
> 3. a stated Vegetation Inspection frequency
>
> 4. an annual work plan[102]

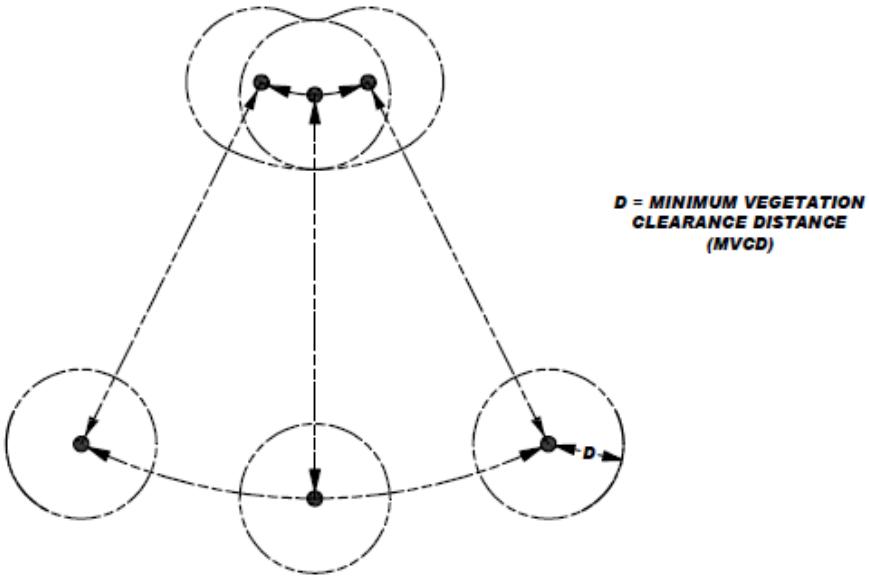
NERC also has indicated in its filing that "prudent vegetation maintenance practices dictate that substantially greater distances [than the applicable MVCD] will be achieved at time of vegetation maintenance."[103]

68. NERC also explains that a conductor's position in space at any point in time continuously changes in reaction to a variety of factors, such as the amount of thermal and physical loading, air temperature, wind velocity and direction, and precipitation. The following diagram is a cross-section view of a single conductor at a given point along the span that illustrates six possible conductor positions due to movement resulting from thermal and mechanical loading:[104]

[102] NERC Response to Data Request Q4 (emphasis added) (citing NERC Petition, Ex. A at 19-20).

[103] NERC Petition, Ex. A (Proposed Reliability Standard FAC-003-2) at 26 (Table 2 – Minimum Vegetation Clearance Distances (MVCD) For Alternating Current Voltages), n. 7.

[104] NERC Petition, Ex. A at 20-21.



NERC indicates that conductor movements must be taken into account under FAC-003-2, and that the transmission owner is required to show that its approach to vegetation management under Requirement R3 will prevent encroachments under all expected line positions.[105] Thus, a transmission owner must manage vegetation to ensure it does not encroach into the MVCD under multiple conditions.

69. Finally, as NERC explains in its Technical Reference Document, transmission owners will have to clear vegetation to levels "well away from" the minimum spark-over zone:

> As the conductor moves through various positions [due to thermal loading and physical loading], a spark-over zone surrounding the conductor moves with it. . . . At the time of making a field observation, however, it is very difficult to precisely know where the conductor is in relation to its wide

[105] *See id.* and Requirement R3 of FAC-003-2; *see also* NERC Petition, Ex. I (Technical Reference Document) at 20-29.

> range of all possible positions. Therefore, Transmission Owners must adopt maintenance approaches that account for this dynamic situation.
>
> . . .
>
> In order to maintain adequate separation between vegetation and transmission line conductors, the Transmission Owner must craft a maintenance strategy that keeps vegetation well away from the spark-over zone mentioned above.[106]

70. Thus, while clearances required at the time of maintenance may vary from one region or area to another, our proposed approval of FAC-003-2 is based on our understanding, which is drawn directly from NERC's statements in its petition, that transmission operators will manage vegetation to distances beyond the MVCD to ensure no encroachment into the MVCD.

71. As discussed above, the PNNL Report identifies specific potential concerns regarding NERC's approach to calculating minimum clearance values, such as the appropriate "gap factor" to apply. In its response to the PNNL Report, NERC explains the Standard Drafting Team's approach to reach a 1.3 gap factor and how it considered the matters raised in the PNNL Report. For example, with regard to the gap factor, NERC indicates that the drafting team relied on an authoritative source and chose a conservative gap factor value.[107] Based on the record in this proceeding, the application of the Gallet equation appears to be one reasonable method to calculate MVCD values.

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[106] NERC Petition, Ex. I (Technical Reference Document) at 21-24.

[107] NERC Comments on PNNL Report at 6-7.

Further, while questions have been raised regarding certain inputs into the mathematical formula, we believe that NERC has supported use of the MVCD values set forth in FAC-003-2.

72. Notwithstanding our approval of the proposed MVCD, we remain concerned, as indicated in Order No. 693, over the lack of empirical data with regard to actual flashover distances observed through testing or analysis of flashover events.[108] NERC states in its petition that the Electric Power Research Institute (EPRI) is planning to undertake "the first known field tests of energized high voltage conductor flash-over to vegetation" at its Lenox facility, and that EPRI could be ready to commence such testing by the summer of 2013.[109] We seek comment on the status of this project and any other similar testing that is planned or ongoing of which NERC or other commenters are aware.

73. NERC further states that "the results of those [EPRI] tests may be useful to the industry for future reviews of this NERC standard."[110] We agree with NERC. While we accept NERC's approach to determine the MVCDs between conductors and vegetation needed to prevent flashovers, we believe it is important that NERC develop empirical evidence that either confirms the MVCD values or gives reason to revisit the Reliability Standard. Accordingly, consistent with the activity that NERC has already initiated, the

[108] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 735.

[109] NERC Petition at 5, n. 10.

[110] *Id*.

Commission proposes to direct that NERC conduct or commission testing to obtain empirical data and submit a report to the Commission providing the results of the testing. We seek comment on this proposal, as well as the appropriate time frame for completion of the required testing and the submission of a report.

2. Designation of Medium VRF for Requirement R2

74. Requirement R1 of currently-effective Reliability Standard FAC-003-1 requires a transmission owner to maintain a "transmission vegetation management program" pursuant to which a transmission owner must maintain certain clearance distances between applicable transmission lines and vegetation. Requirement R1 of the Version 1 standard is assigned a "high" Violation Risk Factor.

NERC Petition

75. Under FAC-003-2, NERC proposes to bifurcate the assigned Violation Risk Factor levels, depending on the type of transmission line involved. NERC proposes to assign a high Violation Risk Factor to Requirement R1, which requires transmission owners to "manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path." Requirement R2 of the proposed Reliability Standard, which is assigned a medium Violation Risk Factor, provides that "[e]ach Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path." [Emphasis in original.] Thus, the substantive obligation set forth in Requirements R1

and R2 are identical, but the Violation Risk Factors differ based on whether a transmission line is an element of an IROL or Major WECC Transfer Path.

76. NERC maintains that the assignment of a medium Violation Risk Factor for Requirement R2 is appropriate pursuant to existing Violation Risk Factor definitions and guidelines. NERC maintains that "[l]ines that are not IROLs and are not Major WECC Transfer Paths by definition have less potential for leading to cascading, separation or instability."[111] Thus, NERC asserts that the separation into high risk and medium risk categories "ensure entities properly understand the risk to reliability associated with specific actions."[112]

Commission Proposal

77. Based on the information provided in NERC's Petition, it is not clear that NERC has adequately supported a medium Violation Risk Factor designation for Requirement R2. The Commission-approved definition of a "medium" risk requirement is:

> A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is *unlikely to lead to bulk electric system instability, separation, or cascading failures . . . .* [113]

[111] NERC Petition at 53.

[112] *Id.* at 54.

[113] *See North American Electric Reliability Corp*., 119 FERC ¶ 61,145 at P 9, *order on compliance*, 121 FERC ¶ 61,179, at n.2, Appx. A (2007) (emphasis added).

The definition of a high Violation Risk Factor is:

> A requirement that, if violated, *could directly cause or contribute to* bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures . . . .[114]

NERC's support for the medium designation is that transmission lines that are not IROLs and are not Major WECC Transfer Paths "have less potential for leading to cascading, separation, or instability" than lines that are IROLs or Major WECC Transfer Paths.[115] But NERC does not explain *why* outages on these relatively high voltage lines (200 kV or higher) would not likely lead to cascading, separation, or instability, or provide any indication of the number of transmission lines and transmission line-miles that would now be subject to a reduced (i.e., medium) Violation Risk Factor designation if FAC-003-2 were in effect.

78. Moreover, transmission lines not designated as an IROL element (or the equivalent) have been instrumental in causing major blackouts, including the August 2003 Northeast blackout. In that case, at least three of the four 345 kV lines (Star-S Canton, Harding-Chamberlin, and Hanna-Juniper) that tripped due to tree contact were not monitored as a flowgate, which could be viewed as the technical equivalent of

[114] *Id.* (emphasis added).

[115] NERC Petition at 53.

an IROL at that time.[116] These three lines were the second, third and fourth lines to trip.[117]

79. Likewise, an August 10, 1996 blackout in WECC began with the trip of a 500 kV line (due to a tree contact) that was not identified as part of WECC's relevant path catalog at the time, i.e., the line was not identified as one of the critical paths subject to WECC monitoring and oversight similar to that required for a Major WECC Transfer Path today.[118]

80. Pursuant to proposed Requirements R1 and R2, transmission owners must "manage vegetation to prevent encroachments into the MVCD of its applicable lines," and any encroachment is considered a violation of these requirements regardless of whether it results in a sustained outage. NERC explains that it bifurcated the requirement to eliminate commingling of higher risk reliability objectives and lesser risk reliability objectives. However, analysis of the two aforementioned system disturbances suggests

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[116] 2003 Blackout Report at 55, 57, 60. The NERC Glossary defines a flowgate as: "1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System." NERC Glossary at 20.

[117] 2003 Blackout Report at 46 (Fig. 5.1).

[118] The blackout originated with the trip of the Keeler-Allston 500 kV line, *see* NERC 1996 System Disturbances: Review of Selected Electric System Disturbances in North America (August 2002) at 40, 47, and affected 7.5 million people and 28,000 MW of load across fourteen states. 2003 Blackout Report at 106.

that lines that are not designated as an IROL or a Major WECC Transfer Path at a given point in time (i.e., proposed Requirement R2 lines), may still be associated with higher-risk consequences, including outages that can lead to Cascading.

81. Accordingly, pursuant to our Violation Risk Factor guidelines, which require, among other things, consistency within a Reliability Standard (guideline 2) and consistency between requirements that have similar reliability objectives (guideline 3), we propose to modify the Violation Risk Factor assigned to Requirement R2 from medium to high. However, in its comments on this NOPR, NERC is free to provide additional explanation than provided thus far to demonstrate the lines identified in Requirement R2 are properly assigned a medium Violation Risk Factor.

D. Enforceability

NERC Petition

82. In its petition, NERC describes its approach to enforcement with respect to each of the Reliability Standard's requirements, noting that each requirement is associated with a specific measure for evaluating compliance and Violation Severity Level guidance. With respect to Requirements R1 and R2, NERC explains that the associated measure sets out the types of evidence or documentation that will be required to show that vegetation was managed to prevent encroachments.

83. NERC acknowledges that proposed Requirements R1 and R2 include a general footnote (Footnote 1) describing multiple conditions exempting a transmission owner from these requirements so as not to be held accountable for an encroachment (e.g., a natural disaster or a "major storm" as defined either by the transmission owner or an

applicable regulatory body). However, NERC explains that this exception would only apply to situations that are beyond the control of the transmission owner or its duly appointed delegate.[119] Further, any determination by the Commission or any other "applicable regulatory body" as to whether a given event does or does not qualify as a "major storm" would override any such determination by the transmission owner.[120]

84. With respect to the Requirement R3 obligation that a transmission owner document its approach to vegetation management, NERC explains that the transmission owner must not only demonstrate that its program takes into account "the movement of the conductor, as well as growth rate, control method, and inspection frequency," it must also provide "documentation that is sufficient to satisfy the auditor that the information contained in that documentation is sufficient that the Transmission Owner can use it to prevent encroachment into the MVCD."[121] NERC further explains that "[a]uditors will have to use judgment to evaluate the appropriateness of the documentation provided given the particular circumstances of the entity being audited."[122]

85. With respect to the obligation in Requirement R4 to provide notice to the applicable control center of a confirmed vegetation condition likely to cause a fault, NERC again explains that auditors may have to use judgment based on the specific

[119] NERC Petition at 34.

[120] NERC Petition at 34.

[121] *Id.* at 35.

[122] *Id*.

circumstances, "but it is expected that an entity that does not make this reporting a top priority would be in violation of the standard."[123] In addition, NERC explains that the obligation to notify without intentional delay generally "can be understood to include an immediate (within 1 hour of the observation) communication notwithstanding a safety issue to the personnel, other immediate priority maintenance functions to ensure reliability or system stability, or communications equipment failure that precludes immediate communication."[124]

86. With respect to Requirement R5, NERC explains that in the case where a transmission owner is prevented from taking actions needed to prevent an encroachment into the MVCD, the transmission owner must de-energize or de-rate the line to reduce the MVCD as needed to avoid a violation, and must show proof that it has taken that action if needed.[125]

87. With respect to Requirement R7 covering vegetation work plans, NERC notes that the requirement does not explicitly require the creation of such a plan, but states that "entities will not be able to comply with the requirement without having a documented plan."[126] While NERC acknowledges that R7 allows transmission owners to have a

[123] *Id.*

[124] *Id.* at 37.

[125] *Id.*

[126] *Id.* at 39.

"dynamic work plan," it points out that any modifications to the plan must be executed to avoid encroachment of vegetation into the MVCD. Moreover, NERC notes that "[a]ny such encroachment would be a violation of R1 or R2, and any changes to the plan that resulted in such an encroachment would be a violation of R7."[127] Finally, NERC notes that auditors will be able to request and review initial work plans for comparison with completed work plans in order to assess compliance with these requirements.[128]

88. In addition, NERC has identified what it expects a transmission owner's vegetation management program to contain. See P 67, *supra.*

89. The proposed Reliability Standard, as filed, includes a "Guideline and Technical Basis" document that further explains NERC's expectations on how the requirements will be enforced and how compliance can be demonstrated. For example, with respect to Requirement R3, NERC explains in greater detail that the documentation showing the transmission owner's approach to vegetation management must provide "the basis for evaluating the intent, allocation of appropriate resources, and the competency of the Transmission Owner in managing vegetation."[129] While NERC notes that there are many acceptable approaches to vegetation management, the transmission owner must be able to

[127] *Id.*

[128] *Id.* at 40.

[129] *Id.*, Ex. A at 19.

show how it conducts work to maintain the required clearances.[130] In addition, as discussed in paragraphs 67-71 above, transmission owners cannot show compliance with the standard without adopting a vegetation management program that keeps vegetation away from the MVCDs under changing conditions.

Commission Proposal

90. We support NERC's overall efforts to develop explicit, verifiable measures for each requirement in order to allow for consistent, non-preferential enforcement.

91. As noted above, NERC has provided information we believe is useful to an overall understanding of the intent of the standard and how it will be interpreted and enforced, including the information that NERC has provided in its petition, in the Guideline and Technical Basis document that is attached as part of Exhibit A to the petition, and in its May 25, 2012 responses to the Commission staff's data requests. We believe these additional resources, while not setting forth requirements or themselves determining whether compliance has occurred, provide guidance with respect to uniform compliance with the proposed Reliability Standard.[131] We expect that NERC will approach its compliance, auditing and enforcement obligations as described in each of these submitted materials. We seek comment as to whether this material should be consolidated as reference material to complement the proposed compliance measures in order that entities

[130] *Id.* at 20.

[131] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 253.

that must comply can find these materials in one place and assure implementation of the proposed standard as NERC has supported in its filings.

92. In addition, Requirement R4 requires transmission owners to notify "without intentional time delay" the control center with switching authority for the applicable line when the transmission owner has confirmed the existence of a vegetation condition that is likely to cause an imminent fault. We seek comment on how NERC would or should treat a delay in communication caused by the negligence of the transmission owner or one of its employees, where the delay may be significant and "unintentional."

E. Reporting Requirements

93. Reliability Standard FAC-003-1, Requirements R3 and R4, require quarterly reporting to the Regional Entities of sustained transmission outages caused by vegetation. While the proposed Reliability Standard moves these reporting requirements to the "Additional Compliance Information" section as a Periodic Data Submittal, NERC maintains that the reporting requirements remain enforceable under NERC's Rules of Procedure. Among other things, NERC states that it and Regional Entities can require entities to provide "such information as is necessary to monitor compliance with the reliability standards" under Section 401.3 of NERC's Rules of Procedure.[132] In addition, NERC asserts that it "has certain courses of action it may undertake as necessary to

[132] NERC Rules of Procedure Section 401.3.

ensure the entity complies with the Rules," pursuant to NERC Rule of Procedure Section 100, including notifying the Commission of the entity's failure to comply.[133]

94. We agree that pursuant to section 401.3 of NERC's Rules of Procedure, NERC and the Regional Entities can require transmission owners to make quarterly reports of sustained transmission outages because these reports provide information relating to compliance with the requirements of proposed FAC-003-2. This rule states: "All Bulk Power System owners, operators and users shall provide to NERC and the applicable Regional Entity such information as is necessary to monitor compliance with the Reliability Standards." Further, a periodic data submittal is a requirement to provide compliance information pursuant to section 3.6 of NERC's Compliance Monitoring and Enforcement Program.[134] However, we seek comment on NERC's statement regarding the "courses of action" that are available to it in order to ensure compliance, other than notifying the Commission of the entity's failure to comply.

F. Definitions

95. We propose to accept the new definition of Minimum Vegetation Clearance Distance and the revised definitions of Vegetation Inspection and Right-of-Way for

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[133] *See* NERC Petition at 31-32. *See* NERC Rule of Procedure, Section 100 ("[e]ach Bulk Power System owner, operator, and user shall comply with all Rules of Procedure of NERC that are made applicable to such entities . . . . If NERC determines that a Rule of Procedure has been violated, or cannot practically be complied with, NERC shall notify [the Commission] and take such other actions as NERC deems appropriate to address the situation").

[134] NERC Rules of Procedure, Appx. 4C § 3.6.

inclusion in the NERC Glossary of Terms. However, we seek further comment regarding the proposed revision to the definition of Right-of-Way, as discussed below.

Revised Definition of Right-of-Way

96. As noted above, we directed NERC in Order No. 693 to consider FirstEnergy's suggestion that "rights-of-way be defined to encompass the required clearance areas instead of the corresponding legal rights, and that the standards should not require clearing the entire right-of-way when the required clearance for an existing line does not take up the entire right-of-way."[135] In response to this directive, NERC now proposes the following new definition of Right-of-Way (ROW):

> The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

97. Under Requirements R1.1 and R2.1 of the proposed Reliability Standard, encroachments into the MVCD observed in real time would be violations of R1 or R2 regardless of whether they cause a sustained outage and regardless of whether the vegetation is within the Right-of-Way as defined under FAC-003-2. However, under proposed Requirements R1.2, R1.3 and R1.4 and the corresponding sub-requirements of R2, fall-ins, blow-ins and grow-ins that cause a sustained outage are violations of the

[135] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 734.

proposed standard only if they occur from *inside* this newly-defined Right-of-Way, which could give transmission owners the perverse incentive to "define" a particular Right-of-Way as narrowly as possible in order to limit the likelihood of an R1 or R2 violation.

98. In response to the Commission staff data requests, NERC has provided information suggesting that encroachments from within the legal right-of-way (i.e., the area within the transmission owner's control) would, in most cases, still be violations of FAC-003-2, even if the Right-of-Way is more narrowly defined. In response to Commission staff's question about a transmission owner's obligation to respond when it identifies a vegetation condition that might encroach into the MVCD if the vegetation is located outside of the Right-of-Way (as proposed under the new definition), but within the transmission owner's *legal* right-of-way, NERC provided the following explanation:

> **1. A grow-in from a tree or the tree wall into the ROW.** The definition of ROW provides for "The corridor of land under a transmission line(s) needed to operate the line(s)." Therefore, in order to operate the line consistent with its rating, the ROW includes space for "blowout" of the lines within the context of the MVCD. With respect to the grow in of a tree from outside the ROW as defined but within the legal ROW, the TO will use vegetations [sic] inspections to identify "those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection." In the event, an inspection shows that a tree has already grown inside the MVCD, the TO would be in violation of R1 item 1 or R2 item 1. Another way to consider this issue is that tree growing into the MVCD from the side is no different from a tree growing into the MVCD from below the line.
>
> **2. A fall-in of danger timber (dead, diseased or dying) from outside of the ROW but within the TO's control.** The definition of inspection covers vegetation "….vegetation conditions on a Right-of-Way and those vegetation conditions

> *under the Transmission Owner's control* that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection." Under this requirement, if the TO is regularly identifying its danger trees and has a program for managing the risk of fall-in there would be no violation. Conversely, if an outage occurs and it is confirmed that the TO was not attempting to identify its danger timber risk, the TO would be in violation of R6. . . . Also, if the TO identifies the danger tree but puts no plan into effect to manage the risk of fall-in, the TO would be in violation of R7 . . . .[136]

99. NERC distinguishes these cases from a case where a fall-in occurs from a *green or healthy tree* outside the corridor-based Right-of-Way, but within the right-of-way controlled by the transmission owner. In that case, NERC acknowledges that there would be no violation under the proposed standard, and maintains that the "fact that the Transmission Owner owns additional ROW over and above . . . that needed by the MVCD is insufficient reason to cut healthy green trees. To require the cutting of green, healthy trees that pose no known threat would likely not be environmentally, socially, or politically acceptable."[137]

100. We agree with NERC that in the situation in which a fall-in occurs from a green or healthy tree outside the corridor based Right-of-Way, but within the ROW controlled by the transmission owner, there would be no violation under the revised Reliability Standard. Moreover, we note that the proposed Reliability Standard does not require clear-cutting along the right-of-way, but instead gives the transmission owner the

[136] NERC Data Responses, Responses to Q9 (May 25, 2012).

[137] *Id.*, Response to Q 9 at P 3.

flexibility to adopt an appropriate vegetation management strategy to comply with FAC-003-2 based on the particular circumstances for a given line. As NERC notes in its Technical Reference Document, different vegetation management strategies may be appropriate for different areas, and FAC-003-2 gives transmission owners the option to adopt strategies to comply with FAC-003-2 that encourage active vegetation management and Integrated Vegetation Management rather than clear-cutting.[138] NERC's Technical Reference Document describes ANSI A-300 – Best Management Practices for Tree Care Operations and identifies Integrated Vegetation Management as a best management practice, including incorporation of wire-border zone management techniques and the establishment and maintenance of compatible vegetation.

101. However, we seek further comment on NERC's enforcement approach with respect to a fall-in by "danger timber" (dead, diseased or dying trees or limbs) from within the transmission owner's legally-owned and controlled right-of-way. Specifically, NERC indicates in its data responses (restated in P 98, *supra*) that "if the TO is regularly identifying its danger trees and has a program for managing the risk of fall-in there would be no violation." The Commission's concern is that this statement could be read to mean that, as long as the transmission owner identifies danger trees and has a program to manage the risk of those trees, an encroachment into the MVCD from a location within the transmission owner's control would not be a violation. The Commission would not

[138] *See* NERC Petition, Ex. I (Technical Reference Document) at 24-29.

agree with such a reading. The mere existence of a program to identify danger trees and a program to manage risk should not shield a transmission owner from enforcement if, notwithstanding the existence of the program, an encroachment into the MVCD occurred. The Commission seeks comment on this reading and, based on the comments, will consider whether changes are needed.

102. We also note that the proposed definition of Right-of-Way includes guidance as to how the transmission owner may define its Right-of-Way, requiring that it be based on construction documents, pre-2007 vegetation maintenance records, or as-built blowout standards. We seek comment on how the identified guidance in the new definition will be used: (1) by the transmission owner to establish criteria to determine an appropriate Right-of-Way; and (2) by auditors to establish criteria to determine compliance with the proposed standard.

G. Implementation Plan

103. We propose to approve the Implementation Plan as submitted in Ex. B of NERC's petition.

V. Information Collection Statement

104. The following collection of information contained in the Proposed Rule is subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[139] OMB's regulations require that OMB

[139] 44 U.S.C. § 3507(d) (2006).

approve certain reporting and recordkeeping requirements (collections of information) imposed by an agency.[140] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

105. The Commission is proposing to submit these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of the PRA. Comments are solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of the provided burden estimate, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

106. This Notice of Proposed Rulemaking proposes to approve Reliability Standard FAC-003-2, which includes certain requirements to create and maintain records related to a transmission owner's vegetation management work plan and its performance of inspections. Because transmission owners have vegetation management plans they follow per the existing transmission vegetation management standard (FAC-003-1), and must compile and maintain similar records and provide similar reports under the existing standard, the proposed revisions are expected to have a minor impact on the burden of

[140] 5 C.F.R. § 1320.11 (2012).

record-keeping and reporting. In addition, by allowing greater flexibility compared to the currently-effective Version 1 standard with regard to the materials that must be maintained for a vegetation management plan or strategy, the NERC proposal may prove to reduce the reporting burden for some entities.

107. Public Reporting Burden: Our estimate below regarding the number of respondents is based on the NERC compliance registry as of July 24, 2012. According to the compliance registry, NERC has registered 330 transmission owners within the United States. Transmission owners must report and retain certain data pursuant to the currently effective Version 1 Standard. Thus, the burden estimate below is based on the potential change in the reporting burden imposed by proposed FAC-003-2. As discussed earlier, Requirement R3 of NERC's proposal provides more flexibility for transmission owners in preparing and maintaining a vegetation management program, and the incremental change in the burden may be negligible or even decrease for some portion of transmission owners. The individual burden estimates are based on each transmission owner having to perform a one-time review of the revised Reliability Standard's information collection requirements and to make any required modifications to its existing vegetation management plans and documentation procedures. In addition, the burden estimate takes into account an on-going, albeit very minor increase in the quarterly reporting burden, based on the increased burden to confirm whether or not reportable outages have occurred on lines not previously subject to FAC-003-1's requirements. Further, the burden estimate takes into account the increased recordkeeping burden associated with the proposed standard's annual vegetation inspection requirements, which is estimated to

increase the inspection cycles (and the associated documentation to demonstrate compliance) for about one third of transmission owners (110 transmission owners).

FAC-003-2 (Transmission Vegetation Management)	Number of Transmission Owner Respondents (1)	Number of Responses per Respondent (2)	Average Burden Hours Per Response (3)	Total Annual Burden Hours (1)x(2)x(3)
One time review and modifications to existing documentation, plans and procedures	330	1	16	5,280 (one-time)
Quarterly Reporting	115	4	0.5	330[141]
Annual Vegetation Inspections Documentation	110	1	2	220
Total				5,830

Total Annual Hours for Collection: (Compliance/Documentation) = 5,830 hours.

Quarterly Reporting Cost for Transmission Owners: = 330 hours @ $70/hour[142] = $23,100.

[141] While approval of FAC-003-2 is not expected to increase the number of reports made or the number of reportable outages experienced, some utilities may experience a very slight increase in the amount of time required to confirm whether or not any reportable outages occurred due to the increased applicability of the standard to certain sub-200 kV transmission lines.

[142] This figure is the average of the salary plus benefits for a manager and an engineer. The figures are taken from the Bureau of Labor and Statistics at http://bls.gov/oes/current/naics3_221000.htm.

Annual Vegetation Inspections Documentation: = 220 hours @ $28/hour[143] = $6,160.

Total Annual Cost (Reporting + Record Retention): = $23,100 + $6,160 = $29,260.

One-Time Review and Modification of Plans and Documentation: 5,280 hours @ $52/hour[144] = $274,560.

Title: Mandatory Reliability Standards for the Bulk-Power System

Action: Proposed revisions to collection FERC-725A.

OMB Control No.: 1902-0244.

Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

Frequency of Responses: Annual, quarterly, and one-time.

Necessity of the Information: The proposed revision of NERC standard FAC-003-2 Transmission Vegetation Management is part of the implementation of the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk Power System. Specifically, the proposal would ensure that transmission owners are protecting transmission lines from encroachment of vegetation.

Internal Review: The Commission has reviewed the proposed revision to the current Reliability Standard and made a determination that its action is necessary to implement

[143] Wage figure is based on a Commission staff study of record retention burden.

[144] This figure is the average of the salary plus benefits for an engineer and a forester. The figures are taken from Bureau of Labor and Statistics at http://bls.gov/oes/current/naics3_221000.htm.

section 215 of the FPA. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimate associated with the information requirements.

108. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

109. For submitting comments concerning the collection of information and the associated burden estimate, please send your comments to the Commission and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4638, fax: (202) 395-7285]. For security reasons, comments to OMB should be submitted by e-mail to: oira_submission@omb.eop.gov. Comments submitted to OMB should include Docket Number RM12-04 and OMB Control Number 1902-0244.

VI. Regulatory Flexibility Act Certification

110. The Regulatory Flexibility Act of 1980 (RFA)[145] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that

[145] 5 U.S.C. §§ 601-612 (2006).

accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA's) Office of Size Standards develops the numerical definition of a small business.[146] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[147]

111. Proposed Reliability Standard FAC-003-2 will be applicable to overhead transmission lines operated at 200 kV or higher, and, for the first time, to transmission lines operated at less than 200 kV if they are elements of an IROL as defined by FAC-014 or elements of a Major WECC Transfer Path. In addition, Proposed Reliability Standard FAC-003-2 will require annual vegetation inspections for all applicable lines, which could result in an increase in annual inspections performed for a subset of transmission owners.

112. Comparison of the NERC Compliance Registry with data submitted to the Energy Information Administration on Form EIA-861 indicates that, of the 330 transmission owners in the United States registered by NERC, 127 of these entities qualify as small businesses. The Commission estimates that the 127 transmission owners that qualify as

[146] 13 C.F.R. § 121.101 (2012).

[147] 13 C.F.R. § 121.201, Sector 22, Utilities & n.1.

small businesses will incur increased costs associated solely with a one-time review of the proposed standard and modification to existing plans and procedures. As described in the information collection section of this NOPR, the estimated cost for the increased data collection and retention is approximately $1,000 per entity.

113. Further, some transmission owners that qualify as small entities will incur costs associated with an increase in frequency of inspections. As indicated above, currently-effective FAC-003-1 requires periodic vegetation management inspections of transmission line rights-of-way at an interval determined by each transmission owner. Requirement R6 of the proposed standard would require each transmission owners to inspect 100 percent of the transmission lines at least once per year. Based on a review of available information, including data provided in response to a 2004 vegetation management study performed by Commission staff,[148] we estimate that approximately one third, i.e., 42, of the transmission owners that qualify as small entities would incur costs associated with more frequent inspection cycles. Assuming that (1) such small entities own approximately 50-200 miles of transmission lines, (2) approximately 15-20 miles of transmission line can be inspected per day and (3) cost of labor is approximately $47 per hour,[149] the estimated increase in inspection cost for these

[148] *See Utility Vegetation Management and Bulk Electric Reliability Report from the Federal Energy Regulatory Commission*, p. 8-10 (Sept. 7, 2004). Available at: http://www.ferc.gov/industries/electric/indus-act/reliability/veg-mgmt-rpt-final.pdf.

[149] The wage figure is taken from the Bureau of Labor and Statistics at http://bls.gov/oes/current/naics3_221000.htm.

42 small entities is in the range of approximately $5,000 to 10,000 per entity. As discussed above, NERC's proposal would modify the applicability of the Reliability Standard to include overhead transmission lines that are operated below 200 kV if they are either an element of an IROL or an element of a Major WECC Transfer Path. Based on a review of the Major WECC Transfer Paths and a sample of sub-200 kV IROLs in the Eastern Interconnect, the Commission believes that most, if not all, of the transmission lines subject to the expanded applicability of proposed FAC-003-2 are owned by large entities. Thus, the increased cost of the new rule to small entities appears to be negligible with respect to the expanded applicability of the Reliability Standard.

114. Based on the above, the Commission does not consider the cost of the NERC proposal to be a significant economic impact for small entities because it should not represent a significant percentage of an affected small entity's operating budget.

115. Based on the above, the Commission certifies that the new or revised requirements set forth in proposed Reliability Standard FAC-003-2 will not have a significant economic impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

VII. Environmental Analysis

116. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect

on the human environment.[150] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. The actions proposed here fall within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural or that do not substantially change the effect of the regulations being amended.[151] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

VIII. Comment Procedures

117. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [INSERT DATE 60 days after publication in the **FEDERAL REGISTER**]. Comments must refer to Docket No. RM12-4-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

118. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not

[150] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

[151] 18 C.F.R. § 380.4(a)(2)(ii) (2012).

in a scanned format. Commenters filing electronically do not need to make a paper filing.

119. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

120. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

IX. Document Availability

121. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

122. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

123. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

List of subjects in 18 CFR Part 40

Electric power; Electric utilities; Reporting and recordkeeping requirements.

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Statement

Response to FERC's Proposed Rulemaking on Vegetation Management, Geomagnetic Disturbance Standards

October 18, 2012

WASHINGTON, DC -- The Federal Energy Regulatory Commission issued a notice of proposed rulemaking today proposing to approve the North American Electric Reliability Corporation's vegetation management standard (FAC-003-2). In separate action, the FERC proposed to direct NERC to develop standards that address geomagnetic disturbances and their impacts on the grid.

"The proposed approval of the results-based vegetation management standard is an important recognition of NERC's efforts on addressing this issue," said Gerry Cauley, president and chief executive officer at NERC. "The proposed rulemaking on geomagnetic disturbances provides a framework to address the current vulnerability, and to factor in the scientific and engineering analysis necessary to understand this complex issue."

The proposed rulemaking on geomagnetic disturbances outlines a two-step process for the industry to, first, develop and implement operational procedures to mitigate effects of solar storms, reflecting many of the recommendations outlined in NERC's 2012 geomagnetic disturbance report and, second, to conduct assessments and implement strategies based on those assessments to protect the bulk power system from geomagnetic disturbances.

NERC has placed a high priority on the vegetation management standard and on identifying effects of geomagnetic disturbances on the bulk power system, and looks forward to working with FERC and the industry to continue our efforts to safeguard the grid.

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Document C-15

NPCC, Inc.

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Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems

Approved by the Task Force on Coordination of Operation on April 10, 1989

Revised:	May 23, 1989
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Revised:	February 10, 1993
Revised:	January 21, 1997
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Revised:	October 15, 2003
Reviewed:	August 18, 2005
Revised:	January 11, 2007

Procedures for Solar Magnetic Disturbances
Which Affect Electric Power Systems
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**1.0 Introduction ••••••

1.0 Introduction

Solar Magnetic Disturbances (SMD) are events that occur on the sun which can ultimately affect man-made systems on earth, including power systems. Voltage potentials are induced in the earth's crust which in turn cause geomagnetically induced currents (GIC) to flow in transmission lines. The resulting GICs are predominantly direct currents in nature and are typically more prevalent in the more northerly latitudes and in those regions in which the resistivity of the earth's crust is high to a considerable depth. This is notably the case in areas of igneous rock deposits.

Those utilities most affected by solar activity since 1989 have developed procedures which establish a safe operating posture and which are initiated by criteria for their respective systems.

A detailed technical description of SMDs may be found Appendix F.

2.0 Impacts on Power Systems

The flow of GICs in the transmission system may affect the following equipment:

2.1 General Effects

2.1.1 Power Transformers

The presence of GIC produces off-setting dc excitation in a transformer, resulting in some degree of core saturation. This can cause the production of **harmonic currents** which can distort system voltages and cause **protective relay** operation due to the flow of neutral current to ground. Core saturation can also result in internal localized heating of the core and windings, and degradation of winding insulation. Saturated transformers are **reactive power** sinks, using up system reactive capacity, resulting in voltage depression.

2.1.2 HVdc Systems and **Static VAR Compensators**

Operations at or near the minimum or maximum current **rating** of HVdc circuits increases the potential for **commutation failures**, jeopardizing continuity of service.

These systems require a sinusoidal voltage to properly commutate current transmission. Voltage distorted by **harmonics** may be severe enough to cause **commutation failures** and result in shutdown of such systems.

Filter banks, including capacitor banks, associated with these systems will tend to overload due to harmonic current and may result in tripping.

2.1.3 Shunt Capacitor Banks

Shunt capacitor banks will tend to overload due to **harmonic current**, typically the third **harmonic**.

2.1.4 Generators

Automatic voltage regulators (AVR) associated with generators require representative voltage signals to control the dc field current on generators. Distorted ac voltage input to the AVR may result in uncertain translation of the ac signals for control, possibly resulting in a cyclical level of excitation on the generator, and hence real and **reactive power** output may vary in an abnormal manner.

Overheating may occur in large generators due to imbalances in phase currents and **harmonic** distortion in voltages which result from the saturation of power transformers. Turbine mechanical vibration may be excited by the presence of increased **harmonic** rotor current.

2.1.5 Transmission Lines

Harmonic frequencies in the system voltage can increase the magnitude of the voltage required to be switched by circuit breakers. **Harmonics** increase transmission losses and cause interference to communications systems.

2.1.6 Overall System Impact

Transformer saturation results in increased VAR consumption and **harmonic** injection into the system. These **harmonic currents** can result in capacitor bank overloading and their tripping, generator tripping and misoperation of **static VAR compensators**. This could further deplete the system of reactive VAR support and impact the overall system performance and security. The power systems are becoming more vulnerable to GIC effects due to longer transmission lines, decreased reactive margins and greater dependence on **static VAR compensators** and high voltage dc control.

3.0 NPCC Alerts of Solar Magnetic Disturbances

The NPCC **Areas** receive, on a continual twenty-four by seven basis, the status of solar activity and geomagnetic storm alerts from the Solar Terrestrial Dispatch (STD). The primary mechanism for notification to the NPCC **Areas** is the Solar Terrestrial Dispatch's Geomagnetic Storm Mitigation System (GSMS), an active communications software package installed on the operator's console. Upon receipt of a geomagnetic storm alert from Solar Terrestrial Dispatch of level Kp 6 or higher, the GSMS simultaneously displays:

- a flashing dialog box advising the operator of a "Major or Severe Geomagnetic Storm Warning." At the discretion of the **Area**, audible warnings will also accompany the flashing dialog box. Both the flashing indicator and the audible warning (if utilized) will continue until the "Confirm Receipt" button is clicked in the dialog box. This sends a verification to Solar Terrestrial Dispatch that the storm alert was received by the NPCC **Areas**. After acknowledging receipt of the geomagnetic storm alert, the GSMS will immediately prompt the operator to specify any GIC activity that has been observed on the power grid. The operator responds by clicking one of the following four buttons, as applicable:

  "No GIC activity has been observed yet."

  "Weak GIC activity has been observed."

  "Moderately strong GIC activity has been observed."

  "Strong GIC activity has been observed."

- a main screen providing the operator with all information currently known about possible solar activity. The following information is presented:

  - the time of the notification in both Universal Time and the **Area's** local time in twenty-four hour format

  - the history of actual hourly Kp readings for the previous seven hours

  - the Kp prediction, together with the predicted time of its onset, and the predicted peak Kp reading for the next twenty-four, forty-eight and seventy-two hours periods

  - the maximum Kp prediction for both the auroral and sub-auroral zones

- the probability of occurrence of the predicted Kp level
- the probable duration of the geomagnetic storm
- a graphical presentation over time of both current historical Kp observations and projected Kp values
- the status of the receipt of the notification by all NPCC **Areas**.

After reviewing the available data, the operator may choose to enact protective measures. Such protective measures taken are to be promptly reported as soon as possible. This is done by clicking on the "Submit Notifications" tab and filling in the box labeled "Specify new actions being taken." Then click on the red arrow to record the actions that are being taken. This permanently records the action taken on the GSMS display and transmits the action to all NPCC Areas. Upon the halting of a previous action taken, the operator is to similarly report these steps using the same interface.

In the event that an **Area** observes GIC activity absent the notification of a geomagnetic storm alert, the operator is to use the "Submit Notifications" feature of the Geomagnetic Storm Mitigation System to automatically notify the other NPCC **Areas** and the Solar Terrestrial Dispatch of the activity.

All time alerts issued by the Solar Terrestrial Dispatch are disseminated in Universal Time (Greenwich Mean Time), a constant scientific time reference. All references to Universal Time may be converted to the prevailing Eastern Time or Atlantic Time as described in Appendix E.

A summary of the levels of solar activity that are made available to the NPCC **Areas** by the STD are shown in Appendix B. Further details can be obtained through the Web site of Solar Terrestrial Dispatch at:

http://www.spacew.com/

4.0 Recommended Procedures

4.1 Operational Planning

On receiving from the Solar Terrestrial Dispatch a forecast of SMD activity expected to result in Kp levels 7, 8 or 9, operations should be reviewed for vulnerability to such storms. Actions should be considered which include, but are not limited to, those listed in Section 4.2.

4.2 Operator Action With the Onset of an SMD

On receiving from the Solar Terrestrial Dispatch a geomagnetic storm alert predicting at least a 40% probability of activity at levels of Kp 7, Kp 8 or Kp 9, or notification of significant GIC activity, **system operators** may evaluate the situation and consider the following actions where appropriate:

4.2.1 Discontinue maintenance work and restore out of service high voltage transmission lines to service. Avoid taking long lines out of service.

4.2.2 Maintain the system voltage within an acceptable operating range to protect against voltage swings.

4.2.3 Reduce the loading on interconnections, critical transmission facilities, and critical transmission interfaces to 90%, or less, of their agreed limits.

4.2.4 Reduce the loading on generators operating at full load to provide reserve power and reactive capacity.

4.2.5 Consider the impact of tripping large shunt capacitor banks and static VAR compensators.

4.2.6 Dispatch generation to manage system voltage, tie line loading and to distribute operating reserve.

4.2.7 Bring equipment capable of synchronous condenser operation on line to provide reactive power reserve.

5.0 Back-Up Communications

5.1 Communications Failure

Although significant redundancy is incorporated in the dissemination of the solar alerts provided by the Solar Terrestrial Dispatch, in the event that all communication is lost with STD, the NPCC will, in the interim, rely on the solar forecasts and alerts issued by the governmental agencies of the United States and Canada. These are, respectively, the Space Environment Center (SEC) of the National Oceanic and Atmospheric Administration (NOAA), located in Boulder, Colorado, referenced in Appendix C, and the Geological Survey of Canada, Department of Natural Resources Canada (NRCAN), located in Ottawa, Ontario, referenced in Appendix D. These communication paths are summarized in Appendix A.

5.2 Conflicting Data

All actions to be considered in section 4.2 are to be based on the forecasts and alerts disseminated by the STD. This data is tailored for the power system in general, and for the geographic subauroral region in which the NPCC transmission system is located. It is therefore unlikely that the STD would predict less solar activity than either the SEC or the NRCAN. However, should the forecasts or alerts of either the SEC or the NRCAN predict higher solar activity than those of Solar Terrestrial Dispatch, each NPCC **Area** will communicate this discrepancy with the STD through the "Submit Notifications" tab of the GSMS and request clarification.

Prepared by:	Task Force on Coordination of Operation
Review frequency:	3 years
References:	*NPCC Glossary of Terms* (NPCC Inc. Document A-07)

Appendix A

Communication Paths

Primary NPCC Notification:

Primary NPCC Notifications	
On a continual basis, through the Solar Terrestrial Dispatch Geomagnetic Storm Mitigation System (GSMS), solar activity is available to:	all NPCC **Areas** (IESO, ISO-NE, NBSO, NYISO and TE)
Upon the prediction of a geomagnetic storm alert of level Kp 6 or higher, the Solar Terrestrial Dispatch GSMS automatically provides alarms to:	all NPCC **Areas** (IESO, ISO-NE, NBSO, NYISO and TE)
For a prediction of Kp 7 or higher, the Solar Terrestrial Dispatch notifies by telephone:	the NYISO; the NYISO in turn notifies the IESO, the ISO-NE, NBSO, and TE.

Back-up NPCC Notification:

SEC (Boulder, Colorado) Forecasts and Alerts	
SEC-Boulder notifies:	New York ISO
New York ISO notifies:	PJM-ISO New England-IESO-TE-NBSO
New Brunswick System Operator notifies:	Nova Scotia Power Incorporated

NRCAN (Ottawa) Forecasts and Alerts	
NRCAN-Ottawa notifies:	IESO-TE
IESO notifies:	New York ISO
New York ISO notifies:	PJM-ISO New England-NBSO
New Brunswick System Operator notifies:	Nova Scotia Power Incorporated

Note: The North American Electric Reliability Council (NERC) also receives solar alerts from the Space Environment Center and transmits these alerts to the NERC Reliability Coordinators through the Reliability Coordinator Information System (RCIS).

Appendix B

Solar Activity Reporting Form

The predictive measure of solar activity reported by the Solar Terrestrial Dispatch is the Kp index, a scale divided into 27 zones of solar activity. A description of these zones and the relationship between the observed Kp index and typically observed GIC activity follows:

Kp Index	Solar Activity	GIC Activity
0o	Quiet	No GICs
1-		
1o		
1+		
2-	Unsettled	
2o		
2+		
3-	Active	
3o		
3+		
4-		
4o		
4+		
5-	Minor Storm	Low Level GICs
5o		
5+		
6-	Major Storm	
6o		
6+		
7-	Severe Storm	Moderate GICs
7o		
7+		
8-	Very Severe Storm	Strong GICs
8o		
8+		
9-		
9o		

Appendix C

Solar Alerts Issued by the Space Environment Services (SEC–Boulder, Colorado)

The Space Environment Center (SEC) of the National Oceanic and Atmospheric Administration (NOAA) is located in Boulder, Colorado, and provides warnings and alerts of geomagnetic activity to the New York ISO. The NYISO subsequently disseminates this information to the other operating Areas within NPCC.

SEC warnings and alerts are issued in the form of a daily "A" index up to three days in advance. The "A" index is a measure of the expected geomagnetic activity, based on solar observations, for Fredericksburg, Virginia. The classification of Major Storm (A index of 50 and above) is transmitted to the NPCC Areas. The SEC also includes a probability for "Major Storm" conditions to help users assess the confidence level of the forecast.

SEC warnings and alerts are also issued in the form of the Kp index, which is based on the maximum deviation of the horizontal magnetic field components of the earth relative to a quiet day, within a three hour time period. The Boulder Kp index is based on measurements from the Boulder magnetometer, and it is used at the SEC to define the alert thresholds. A warning or alert is issued for a Kp index of Kp 5 or greater. Most electrical power systems, however, are not affected until the Kp index reaches a level of 7 or higher.

The forecasts and warnings that are made available to system control centers follow:

Warnings

The following Warnings are issued by telephone from the SEC to the NYISO. Warnings are predictions for a certain period in the future. That is, warnings come before the specified period.

A Index = 30
A Index = 50
Kp Index = 5
Kp Index = 6
Kp Index = 7 or above

Alerts

The following Alerts are issued by telephone from the SEC to the NYISO. Alerts are observations of activity that has already occurred. Generally, alerts are issued at the end of the specified period.

A Index = 30
A Index = 50
Kp Index = 5
Kp Index = 6
Kp Index = 7
Kp Index = 8

Rapid Alerts

The following Rapid Alerts are issued by telephone from the SEC to the NYISO. Rapid Alerts are observations of activity that has occurred, but they are issued immediately, without waiting for the end of the period.

Kp Index = 7
Kp Index = 8

Note: The SEC in some cases speaks of all of these messages, including warnings, alerts and rapid alerts, as "alerts," and thus all of the messages can carry an alert code.

All time alerts issued by the SEC are disseminated in Universal Time (Greenwich Mean Time), a constant scientific time reference. All references to Universal Time may be converted to the prevailing Eastern Time or Atlantic Time as described in Appendix E

Further information can be obtained at:

http://www.sec.noaa.gov/today.html

Appendix D

Solar Alerts Issued by the Department of Natural Resources Canada (NRCAN– Ottawa, Ontario)

The Geological Survey of Canada, Department of Natural Resources Canada (NRCAN), located in Ottawa, Ontario, Canada, issues forecasts and warnings, based on magnetometer data from 12 observatories using the Canadian Automatic Magnetometer Observatory System (CANMOS) and on solar data received from sources around the world.

GSC forecasts are updated and issued every hour. They are based on hourly range predictions of geomagnetic activity for up to two days in the future for the subauroral zone, the geographic region in which most of the NPCC Areas are located. The classifications which are of concern to the NPCC Areas are "Stormy" (corresponding to an approximate Kp index of 5 or 6), and "Major Storm" (corresponding to an approximate Kp index of 7, 8, or 9). Several key observatories are continually monitored, and, when events are found that meet predefined criteria, a warning and updated forecast are issued. The forecasts and warnings that are made available to system control centers follow:

Warnings

Warnings issued by the NRCAN are based on actual conditions which have occurred and been observed:

WARNINGS-NRCAN (Ottawa)	
Kp Index	Hourly Range in Nanoteslas (nT)
0	0 to 7
1	8 to 14
2	15 to 29
3	30 to 59
4	60 to 104
5	105 to 179
6	180 to 299
7	300 to 499
8	500 to 749
9	750 and above

Forecasts

Forecasts issued by the NRCAN are projections for expected conditions:

FORECASTS-NRCAN (Ottawa)	
Activity Level	Kp Levels
Stormy	5 and 6
Major Storm	7, 8 and 9

NOTE: NRCAN data is measured at Ottawa, Ontario, Canada; forecasts are projections of conditions expected to occur in the subauroral zone in which most of NPCC is physically located.

All time alerts issued by the NRCAN are disseminated in Universal Time (Greenwich Mean Time), a constant scientific time reference. All references to Universal Time may be converted to the prevailing Eastern Time or Atlantic Time as described in Appendix E.

Further information can be obtained at:

forecast@geolab.nrcan.gc.ca
http://www.geolab.nrcan.gc.ca/geomag

Appendix E

Time Conversion Reference Document

The time reference used in the solar alerts disseminated by the Solar Terrestrial Dispatch, as well as the Department of Natural Resources Canada and the Space Environment Services, is the scientifically accepted Universal Time (UT), which is also equivalent to Greenwich Mean Time (GMT). The prevailing Eastern Time lags Universal Time / Greenwich Mean Time by five hours in the autumn and winter. The prevailing Eastern Time lags Universal Time / Greenwich Mean Time by four hours in the spring and summer. The prevailing Atlantic Time lags Universal Time / Greenwich Mean Time by four hours in the autumn and winter. The prevailing Atlantic Time lags Universal Time / Greenwich Mean Time by three hours in the spring and summer. The Universal Time / Greenwich Mean Time is a constant time reference and does not convert to accommodate daylight savings in the spring and summer. Conversion examples for the Eastern and Atlantic time zones follow:

Eastern Standard Time (EST)	Universal Time (GMT)
12:00 hour	17:00 hour

Eastern Daylight Time (EDT)	Universal Time (GMT)
13:00 hour	17:00 hour

Atlantic Standard Time (AST)	Universal Time (GMT)
13:00 hour	17:00 hour

Atlantic Daylight Time (ADT)	Universal Time (GMT)
14:00 hour	17:00 hour

Appendix F

Description of Solar Magnetic Disturbances

Solar Magnetic Disturbances (SMDs) are events that occur on the sun that can ultimately affect man-made systems on Earth, including power systems. The sun emits a stream of charged particles known as the solar wind that continuously moves outward from the sun past the Earth. Solar activity (solar flares, disappearing filaments and coronal holes) affects the intensity of the solar wind, varying from very quiet levels to very active levels during major storms. Extremely fast coronal mass ejection (CME) events associated with unusually energetic solar flares (known as Fast Transit Events [FTEs]) can reach the earth in as little as fourteen hours. However, most CMEs (including disappearing filament eruptions) require approximately two to three days to travel to the Earth. Coronal hole based disturbances typically take two to four days to reach the Earth. The quiet solar wind can take up to six days to reach the Earth.

The Earth has a magnetic field that is generated by a liquid metal core. This magnetic field penetrates the surface of the Earth and expands outward a large distance into space, effectively creating a cocoon or shield around the Earth that protects the Earth from harmful effects of the solar wind. The domain of the Earth's magnetic field is known as the magnetosphere. Pressure from the solar wind shapes the magnetosphere into a comet-like appearance with a “head” surrounding the Earth and a “tail” (known as the magnetotail) that extends a great distance in a direction that is opposite to the Sun (behind the Earth).

Strong magnetic fields on the Sun are dragged out toward the Earth by the solar wind. As these magnetic fields flow past the Earth, they can interact with the Earth's magnetic field. When the magnetic field lines in the solar wind are oriented in a direction that is opposite to the magnetic field lines from the Earth, the magnetic field lines from the Earth can reconnect with the magnetic fields in the solar wind. This opens up a conduit that allows solar wind momentum energy and particles to directly enter and energize the Earth's magnetosphere. The reconnected field lines are then convected across the Earth's polar regions and are dragged by the solar wind into the magnetotail region of the Earth's magnetosphere. The build-up of additional magnetic flux in the magnetotail can eventually trigger powerful magnetic field reconnection events in the Earth's magnetotail that both energize and accelerate particles and plasma from the magnetotail toward the Earth. Beams of energized particles are guided by the Earth's magnetic field into the ionosphere where they collide with atmospheric constituents and fluoresce as aurora (northern lights). The aurora are produced within a ring of activity that encircles the earth's geomagnetic poles, usually over the higher latitudes. This ring is known as the auroral zone.

Within the auroral zone ionosphere, powerful electrical currents (auroral electrojets) are forced to flow to help dissipate the tremendous energy that is released during the magnetotail reconnection events. Currents in the dusk regions flow eastward while currents in the dawn regions flow westward. These current systems converge near local midnight. The region where these currents converge is known as the Harang discontinuity region. Although the intensity of these currents can rapidly change during a geomagnetic storm, the most significant and hazardous changes typically occur near the midnight Harang discontinuity region where eastward-directed currents may suddenly change direction to westward directed currents. Significant changes in the intensity and / or the direction of these current systems can induce ground-based voltage (potential) differentials between locations spaced some distance apart. These ground potential differences can cause currents to flow through the grounded connections of transmission lines if the resistivity of the ground to a respectable depth is higher than the resistivity of the transmission line. This condition occurs more frequently and with greater magnitude in areas that overlie igneous rock.

The flow of these currents into transmission lines is known as geomagnetically induced currents (GICs). They are ostensibly direct currents in nature and are most often located toward the higher latitudes within the auroral zone during quiet to modestly active geomagnetic conditions. However, as geomagnetic storm activity intensifies, the size of the auroral zone expands. This expansion causes the equatorward boundary of the auroral electrojets (the southern-most location of the intense ionospheric electrical current systems) to migrate toward lower latitudes. During extreme events, the auroral electrojets can move at least into the central United States. This equatorward motion and the concurrent intensification of the ionospheric electrical currents during significant geomagnetic storms can therefore expose a considerable portion of the North American power grid to GICs that may be considerably stronger than those observed over the higher latitudes or during quieter geomagnetic intervals.

Commissioner John R. Norris Statement
October 18, 2012
Docket Nos. RM12-22-000 and RM12-4-000
Item Nos. E-2 and E-3

Proposed Enhancements to Reliability of Bulk Power System

"These two reliability orders address two distinctly different challenges, and represent two different approaches to maintaining reliability. E-3, concerning Reliability Standard FAC-003-2 on Transmission Vegetation Management (FAC-003), to me is about executing the fundamentals necessary to keep the lights on. We know that, without continuous care of transmission rights of way, vegetation growth will, without question, grow into power lines and impact reliability. This second version of FAC-003 recognizes the inevitability of outages if vegetation management is not in a continual state of maintenance, and also recognizes that this maintenance must be preformed on all transmission facilities that have an impact on reliability. The inclusion of Interconnection Operating Limit (IROL) elements and Major Western Electricity Coordinating Council (WECC) Transfer Path elements is a good step in recognizing that the applicability of FAC-003 should include sub-200 kV facilities that are critical to grid reliability.

"The threat of geomagnetic disturbances (GMD) addressed in the proposed rule in E-2 is a different but equally important reliability challenge. A poster child for a Low Frequency–High Impact threat, GMD involves a judgment call that requires us to assess the likelihood of occurrence, how severe the impact could be, and the options to guard against that impact. Like a cyber attack, the potential size and duration of an outage that could result from a GMD demands that we take the precautions necessary to prevent, limit, or contain the potential impact. While I do not believe there is a reasonable option that will guarantee that GMDs will never impact the grid, there are shorter and longer-term steps that we can take to guard against their potential impacts. Recognizing that taking these steps will come with costs, we have to find a "sweet spot", if you will, where the cost of implementing reasonable reliability measures to guard against GMD impacts is appropriately balanced against the potential costs of a GMD event.

"Given the magnitude of the potential damage, I believe we are taking the right approach in this order by proposing to require that in stage two, there must be more extensive standards developed than just those that address operational and enhanced training procedures (the subject of stage one). The evidence before us today suggests that some or all vulnerable elements of the system will need further hardening to withstand a GMD. I think we appropriately give deference to NERC to make a needs assessment and design the additional measures necessary (through the development of the stage two standards) to meet the reliability needs identified in those assessments. But, as the proposed rule indicates, timing is of the essence. With the prediction of high solar flare activity on the very near time horizon, NERC will need to develop standards and industry to implement them much more rapidly than has previously been required. Again, this is another judgment call where we must decide what is reasonable and what is necessary. I ask NERC and the industry to accept this challenge and work as expeditiously as possible to meet it.

"In summary I think we have approached vegetation management like you would approach changing the oil in your car. You know that, if you do not do it, at some point your car will breakdown. And, preparing for GMDs is like buying insurance for you car. You hope that you will never need it - and in fact, you might not - but, it would be irresponsible to not determine what level of coverage you do need and to make the necessary investment to protect yourself and others from the risk and potential severity of an occurrence."

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Updated: October 18, 2012

News Release: October 18, 2012
Docket Nos. RM12-22-000, RM12-4-000
Item Nos. E-2 & E-3

FERC Proposes Enhancements to Reliability of Bulk Power System

The Federal Energy Regulatory Commission (FERC) today took steps to ensure continued reliable operation of the nation's bulk power system by proposing to approve a revised vegetation management standard and to require new standards addressing the impacts of a geomagnetic disturbance (GMD).

GMDs, which result in distortions to the earth's magnetic field, may cause severe problems with grid reliability, including blackouts as well as damage to critical or vulnerable equipment. Although strong disturbances are infrequent, current mandatory reliability standards do not adequately address vulnerabilities.

To address this reliability gap, today's Notice of Proposed Rulemaking (NOPR) proposes to direct the North American Electric Reliability Corporation (NERC), the FERC-approved Electric Reliability Organization, to develop and submit new GMD standards in a two-stage process.

First, within 90 days of the effective date of a final rule in the proceeding, NERC would file one or more standards requiring owners and operators of the bulk power system to develop and implement operational procedures to mitigate GMD effects. That such procedures already are in place in some areas should allow for faster development and implementation of these standards, the NOPR says.

In the second stage, FERC proposes that NERC file, within six months of a final rule, standards that require grid owners and operators to conduct initial and continuing assessments of the potential impacts of GMDs and, based on those assessments, implement strategies to protect the bulk power system, including automatic blocking of geomagnetically induced currents, instituting specification requirements for new equipment, inventory management, or isolating certain equipment that is not cost effective to retrofit. Stage two would be implemented in phases, focusing first on the most critical and vulnerable assets.

The NOPR does not propose specific requirements, but offers guidance regarding the assessments of the grid's vulnerability to GMDs, the mechanisms for protecting critical or vulnerable components and an implementation schedule. FERC seeks comments on all aspects of the proposal.

In a separate NOPR on vegetation management, FERC proposes to approve revisions submitted by NERC that would:

- Expand the applicability of the standard to include lines operated below 200 kilovolts that are part of an Interconnection Reliability Operating Limit or a Major Western Electricity Coordinating Council Transfer Path.
- Set a new minimum annual inspection requirement.
- Incorporate new minimum clearance distances into the text of the standard.

Comments on both proposals are due 60 days after publication in the *Federal Register*.

R-13-2

(30)

CONTACT

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From:	Guy V. Zito
To:	rsc
Subject:	FW: NERC: FERC NOPR Issued Proposing to Direct NERC to Develop Geomagnetic Disturbance Reliability Standards
Date:	Friday, October 19, 2012 9:20:51 AM
Attachments:	NOPR_GMD_standards.pdf

To All,

Attached is a FERC NOPR on GMDs. outlining the desire of FERC to direct NERC to develop standards in two phases, the first of which is to, within 90 days of the final rule NERC is to file with the Commission a standard(s) that will require TOs to mitigate the effect of GMDs. Subsequent to this first filing, NERC is to develop a standard(s) requiring TOs to study and identify, on an ongoing basis, the vulnerabilities of their systems to GMD and develop mitigations for those identified risks.

We will have this on the agenda for our November meeting so please be prepared to discussed. Perhaps Sylvain from HQ could arrange for a SME to attend and assist us with discussion since we will be in Montreal. Quebec's 1989 event is referred to in the NOPR as evidence of the significant impact that GMDs may have on the grid. Geomagnetic induced currents can be damaging to transformers and currently there are warning times of between 30 - 60 minutes prior to GMD events currently available. The GMDs do not restrict themselves to just the Grid but also distribution systems and pipelines as well as any electrically conductive surface.

The standard(s) that are developed from this effort could result in very costly mitigations. A different short term approach to this problem could be, given the 30-60 minute warning time, to turn off portions of the grid for the duration of the event and then restore it. There should be sufficient historical data to demonstrate what levels of GMDs the grid effectively "rode through" and perhaps use the highest of these as a threshold. Anything anticipated to be greater than this threshold could trigger public notification and subsequent operator action to "pull the plug" in those areas where the greatest effect from the GMD might be. A peak to the solar cycle is anticipated to be in 2013 and I am concerned with the ability of us to develop standards gain their approval and implemented them to sufficiently harden the grid by this time. I am hopeful all can keep an open mind to solutions and think outside the box for the short term goal. Long term could be a more comprehensive approach to hardening based on the actual risk to the system. Interesting times.

Thanks,

Guy V. Zito
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From: Elizabeth Heenan [Elizabeth.Heenan@nerc.net]
Sent: Thursday, October 18, 2012 3:32 PM
To: reg_corresp_notif

Subject: NERC: FERC NOPR Issued Proposing to Direct NERC to Develop Geomagnetic Disturbance Reliability Standards

To NERC Management and Regional Entity Executives,

Attached please find a Notice of Proposed Rulemaking proposing to direct NERC to develop and submit new Geomagnetic Disturbance standards in a two-stage process. The NOPR was issued today by FERC following the Sunshine Open Meeting in Docket No. RM12-22-000.

Thank you,

Elizabeth A. Heenan
Legal Assistant
North American Electric Reliability Corporation
1325 G Street NW, Suite 600
Washington, DC 20005
Cell: (202) 420-8795
Direct: (202) 644-8040

Y

Commissioner Cheryl A. LaFleur Statement
October 18, 2012
Docket Nos. RM12-22-000 and RM12-4-000
Item Nos. E-2 and E-3

Proposed Enhancements to Reliability of Bulk Power System

"Protecting the reliability of the nation's bulk electric system requires both day-to-day blocking and tackling to make sure that the lights stay on, and preparing for emerging issues including high-impact low-frequency events. Today, we are voting out Notices of Proposed Rulemaking that speak to both these components of reliability.

Vegetation Management Standard

"No issue is more central to reliability than timely and effective tree trimming to keep the transmission system operational. Indeed, a tree contact was a key contributing cause of the 2003 blackout that gave rise to this Commission's jurisdiction over reliability.

"I believe the vegetation management standard (FAC-003-2) that we propose to approve today represents an important step forward in addressing this basic reliability issue. In particular, I note that the new standard includes a requirement to maintain a defined Minimum Vegetation Clearing Distance (MVCD) for all transmission lines above 200 kv and lines below 200 KV that are part of an Interconnection Reliability Operating Limit or WECC Transfer Path, and, for the first time, a requirement to annually inspect 100 percent of the lines subject to the standard. These requirements are both clear and concrete.

"The standard we propose to approve today is one of the first results-based standards put forward by NERC. As I understand the concept of a results-based standard, it includes a clearly defined result – avoidance of outages caused by vegetation within a MVCD—on the basis of which to judge compliance with the standard. Because the standard is judged by results, it proposes to give more flexibility to transmission owners about how to meet those results, as long as they are met. This is an important concept, and the successful implementation of this standard may be a model for further results-based standards.

"I also appreciate the commitment by NERC and the industry, working with EPRI, to fund further empirical research on the proposed MVCD, since that is such a critical element of the proposed standard. I recognize that years of hard work went into this proposed standard, and appreciate the efforts of the NERC standards team as well as everyone here at FERC that worked on the standard.

Geomagnetic Disturbances

"The second Notice of Proposed Rulemaking relates to a very different issue, preventing or mitigating damage to the bulk electric system caused by geomagnetic disturbances resulting from solar storms. Solar storms are an acute example of "High Impact Low Frequency" events, which I believe are among the most difficult, but also the most necessary, to address through standards. Just as our society has over the centuries developed standards to protect elements of our infrastructure from high impact low frequency events like earthquakes and fires, I believe we must begin to address the challenge of making our electric grid resilient to geomagnetic disturbances. This is an issue in which I have taken a strong personal interest. As I have observed, the threat of geomagnetic disturbances damaging the power grid sounds like science fiction, but is in fact based on scientific fact. However, while the fact that geomagnetic disturbances can cause substantial harm to the electric grid is undisputed, the way in which that harm would occur is not without controversy. The technical community has debated whether geomagnetic disturbances caused by solar events would cause the bulk electric system to break apart due to excessive reactive power consumption, cause damage to high-voltage transformers and other key elements of the system due to inductive currents, or some combination of the two. Any of these results is unacceptable, and is exactly the

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sort of cascading disturbance to the bulk power system that section 215 of the Federal Power Act requires us to address. I believe that, while continuing to explore the technical issues, we can and should adopt “No Regrets” actions to prevent and mitigate grid damage from geomagnetic disturbances. The Notice of Proposed Rulemaking we are voting on today includes two such No Regrets actions, both of which are consistent with NERC’s assessment report on GmD issued earlier this year.

“First, we would require NERC to develop and propose a standard that requires transmission owners to take operational steps, to prepare for geomagnetic disturbances. This is one of the first actions proposed in NERC’s assessment and action plan. Because we are approaching a periodic solar maximum in 2013, increasing the threat of damaging solar storms, we are proposing to seek fast action on an operational standard.

“Second, we would require NERC to develop and propose a standard that would require transmission owners to undertake an assessment of the most vulnerable elements of the bulk electric system, and propose steps to prevent or mitigate damage to those elements from geomagnetic disturbances. As indicated in the Notice of Proposed Rulemaking, those steps could include installation of automatic blocking in certain vulnerable and critical transformers, requirement of withstand capability in transformers, inventory management strategies, operational plans to address critical elements of the system, and/or other steps that the industry and NERC may propose. Importantly, the proposed rule gives industry and NERC considerable flexibility of how to address this issue, but not the flexibility to ignore it.

“As with any other program to address pieces of the electric grid—and I have lived through quite a few—the appropriate action steps would likely vary based on how critical an asset was, where it was located, when it was scheduled to be replaced, whether it could be protected by islanding or operating protocols, or whether it needed to be retrofitted with protective equipment. Our collective understanding of these options would likely grow once we started the process.

“I know that the challenge of preparing our bulk electric system for geomagnetic disturbances is very complicated, and complicated challenges require complicated solutions. In the past, the electric grid has undergone many large-scale efforts to refurbish or replace electrical equipment to improve reliability, safety or environmental performance. Because of the size, diversity and continuous operation of the electric grid, these efforts are inevitably more complicated and take longer than expected. To me, that argues for getting started sooner rather than later.

“Finally, I believe it is appropriate to tackle this challenge now because the US is facing considerable investment in our transmission grid, driven by a change in power supply and replacement of aging infrastructure. We have a big opportunity to make sure the next generation of transmission equipment is built to withstand geomagnetic disturbances.

“I hope we will receive a broad range of comments on both Notice of Proposed Rulemaking. I would like to thank the FERC teams that worked on these proposed rules, and on the technical conference on GmD last spring on this issue. Thank you.”

Print this page

Updated: October 18, 2012

From:	Kimberly Mielcarek
To:	Kimberly Mielcarek
Subject:	NERC Statement - Response to FERC"s Proposed Rulemaking on Vegetation Management, Geomagnetic Disturbance Standards
Date:	Thursday, October 18, 2012 5:07:56 PM

Statement

Response to FERC's Proposed Rulemaking on Vegetation Management, Geomagnetic Disturbance Standards

Click for Announcement, FERC Announcement
Norris Statement, LaFleur Statement

WASHINGTON, DC -- The Federal Energy Regulatory Commission issued a notice of proposed rulemaking today proposing to approve the North American Electric Reliability Corporation's vegetation management standard (FAC-003-2). In separate action, the FERC proposed to direct NERC to develop standards that address geomagnetic disturbances and their impacts on the grid.

"The proposed approval of the results-based vegetation management standard is an important recognition of NERC's efforts on addressing this issue," said Gerry Cauley, president and chief executive officer at NERC. "The proposed rulemaking on geomagnetic disturbances provides a framework to address the current vulnerability, and to factor in the scientific and engineering analysis necessary to understand this complex issue."

For more information or assistance, please contact Kimberly Mielcarek.

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141 FERC ¶ 61,045
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM12-22-000]

Reliability Standards for Geomagnetic Disturbances

(Issued October 18, 2012)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission (Commission) proposes to direct the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization, to submit for approval Reliability Standards that address the impact of geomagnetic disturbances (GMD) on the reliable operation of the Bulk-Power System. The Commission proposes to do this in two stages. In the first stage, the Commission proposes to direct NERC to file, within 90 days of the effective date of a final rule in this proceeding, one or more Reliability Standards that require owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System. In the second stage, the Commission proposes to direct NERC to file, within six months of the effective date of a final rule in this proceeding, one or more Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going

assessments of the potential impact of GMDs on Bulk-Power System equipment and the Bulk-Power System as a whole. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs indentified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit. This second stage would be implemented in phases, focusing first on the most critical Bulk-Power System assets.

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER].**

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.

- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

141 FERC ¶ 61,045
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reliability Standards for Geomagnetic Disturbances Docket No. RM12-22-000

NOTICE OF PROPOSED RULEMAKING

(Issued October 18, 2012)

1. Pursuant to section 215(d)(5) of the Federal Power Act (FPA),[1] the Federal Energy Regulatory Commission (Commission) proposes to direct the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), to file for approval with the Commission Reliability Standards (GMD Reliability Standards) that address the risks posed by geomagnetic disturbances (GMD) to the reliable operation of the Bulk-Power System.[2] The Commission proposes to direct NERC to develop the GMD Reliability Standards in two stages. In the first stage, within 90 days of the effective date of a final rule in this proceeding, NERC would file one or more proposed Reliability Standards that require owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the

[1] 16 U.S.C. 824o(d)(5) (2006).

[2] "A geomagnetic disturbance occurs when the magnetic field embedded in the solar wind is opposite that of the earth. This disturbance, which results in distortions to the earth's magnetic field, can be of varying intensity and has in the past impacted the operation of pipelines, communications systems, and electric power systems." Oak Ridge National Laboratory, *Electric Utility Industry Experience with Geomagnetic Disturbances* at xiii (1991), *available at* http://www.ornl.gov/~webworks/cpr/v823/rpt/51089.pdf.

effects of GMDs consistent with the reliable operation of the Bulk-Power System. In the second stage, within six months of the effective date of a final rule in this proceeding, NERC would file one or more proposed Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going assessments of the potential impact of GMDs on Bulk-Power System equipment and the Bulk-Power System as a whole. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD.[3] This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs indentified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents (GICs) from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit.[4] This second stage would be implemented in phases, focusing first on the most critical Bulk-Power System assets.

[3] 16 U.S.C. 824o(a)(4) (2006).

[4] Some examples of automatic blocking include series line capacitors, transformer neutral GIC blocking and/or reduction devices, and selective tripping of vulnerable

(continued…)

2. We take this action based on government-sponsored studies and NERC studies that conclude that GMD events can have an adverse, wide-area impact on the reliable operation of the Bulk-Power System.[5] In a 2010 study prepared for the Commission, Department of Energy, and Department of Homeland Security, the Oak Ridge National Laboratory reported that GMD events can develop quickly over large geographic footprints, having the capability to produce geographically-large outages and significant damage to Bulk-Power System equipment.[6]

3. The seriousness of the risk posed by GMDs to the reliable operation of the Bulk-Power System was expressed at a Technical Conference held on April 30, 2012.[7] At the Technical Conference, several panelists indicated that severe GMD events could potentially compromise the reliable operation of the Bulk-Power System, with some

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assets. Automatic blocking measures can also include the use of relays that can be set so that they are activated only when needed.

[5] *See, e.g.,* The Oak Ridge National Laboratory prepared a study consisting of six technical reports (collectively, "Oak Ridge Study") on the effects of electromagnetic pulses on the Bulk-Power System. *Available at* http://www.ornl.gov/sci/ees/etsd/pes/ferc_emp_gic.shtml; North American Electric Reliability Corp., 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System at 85 (February 2012) (*NERC Interim GMD Report*), *available at* http://www.nerc.com/files/2012GMD.pdf; North American Electric Reliability Corp., *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System* at 68 (June 2010) (*HILF Report), available at* http://www.nerc.com/files/ HILF.pdf.

[6] Oak Ridge National Laboratory, *Electromagnetic Pulse: Effects on the U.S. Power Grid:Meta-R-319* at pages 1-30, 1-31, 4-1 (January 2010) (*Oak Ridge Study 319 Report*), *available at* http://www.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-319.pdf.

[7] Written statements presented at the Technical Conference, post-Technical Conference comments, and Technical Conference transcript are accessible through the Commission's eLibrary document retrieval system in Docket No. AD12-13-000.

noting as an example the GMD-induced disruption of the Hydro-Québec grid in 1989.[8] At the Technical Conference, panelists stated that the current 11-year solar activity cycle is expected to hit its maximum activity in 2013 and large solar events often occur within four years of such a cycle maximum.[9] While strong GMDs are infrequent events, their potential impact on the reliable operation of the Bulk-Power System (e.g., widespread blackouts) requires Commission action under section 215(d)(5) of the FPA.[10]

[8] *See, e.g.*, Statement of Scott Pugh, U.S. Department of Homeland Security at 2 (citing 1989 Hydro-Québec blackout); Statement of Frank Koza, PJM Interconnection, L.L.C. at 1 ("The combination of half-cycle transformer saturation and increased reactive power consumption can lead to voltage collapse and blackouts if not properly managed."); Statement of John Kappenman at 8 ("The bulk power system is the nation's most important critical infrastructure and unlike other threats, a severe geomagnetic storms [sic] can impose a near simultaneous nationwide crippling threat to this vital infrastructure."); Statement of Gerry Cauley, NERC at 1 ("Previous examples, such as the 1989 event in Hydro Québec demonstrate that severe solar storms represent a serious risk that can challenge the reliability of the bulk power system.").

[9] April 30, 2012 Technical Conference Tr. 84:14-19 (Pugh); 106:9-15, 169:1-19 (Murtagh).

[10] 16 U.S.C. 824o(d)(5); *see also Transmission Relay Loadability Reliability Standard*, 134 FERC ¶ 61,127, at P 25 (2011) (explaining that under section 215(d)(5) "the Commission, and not just the ERO, has the responsibility and authority to identify 'specific matters' that it considers appropriate to carry out section 215. Section 215 establishes a paradigm by which both the Commission and the ERO are responsible for identifying reliability gaps—the ERO through its Reliability Standards development process, where it can independently identify areas of concern and develop Standards to address them; and the Commission through its review of proposed Reliability Standards and authority to direct modifications or new Standards that address specific issues necessary to effectuate the purposes of section 215.").

4. Currently, GMD vulnerabilities are not adequately addressed in the Reliability Standards.[11] This constitutes a reliability gap because, as discussed below, GMD events can cause the Bulk-Power System to collapse suddenly and can potentially damage the Bulk-Power System.

5. GMD events affect the Bulk-Power System by introducing geomagnetically-induced currents[12] that can cause "half-cycle saturation" of certain high-voltage Bulk-Power System transformers.[13] Half-cycle saturation of transformers can lead to increased consumption of reactive power and creation of disruptive harmonics that can cause the sudden collapse of the Bulk-Power System.[14] Further, half-cycle saturation from GICs can potentially damage Bulk-Power System transformers because of overheating.[15]

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[11] NERC Reliability Standard IRO-005-3a (Reliability Coordination — Current Day Operations), Requirement R3, is the only existing requirement that discusses GMDs. Requirement R3 requires reliability coordinators to make transmission operators and balancing authorities aware of GMD forecast information and assist as needed in the development of response plans, but it does not require steps for mitigating the effects of GMD events.

[12] GIC is an electrical current created by a solar event that appears as direct current to the bulk electric system. North American Electric Reliability Council, *March 13, 1989 Geomagnetic Disturbance* at 36 (1989), *available at* http://www.nerc.com/files/1989-Quebec-Disturbance.pdf. Automatic blocking prevents or reduces GICs flows into protected Bulk-Power System components without operator intervention. *NERC Interim GMD Report* at 73.

[13] NERC Interim GMD Report at iii-iv. Half-cycle saturation is an abnormal operating condition whereby a transformer operates outside nominal voltage design values, saturating the transformer core with magnetic flux and forcing magnetic flux into other parts of the transformer. *Id.* at 25.

[14] *Id.* at 3 ("GMD can have … a wide range of impacts on power apparatus and power system operations. The effects on apparatus range from nuisance events, such as tripping of electrical equipment, radio interference, and control malfunctions, to large-

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Permanent damage to large transformers due to GICs can lead to restoration delays for the power grid.[16] For example, the Oak Ridge Study assessed the effects of a "1-in-100 year" geomagnetic storm on the modern Bulk-Power System.[17] The Oak Ridge Study simulation concluded that such an event could put a significant number of Bulk-Power System transformers at risk for failure or permanent damage.[18] The Oak Ridge Study simulation also found that the effects of a GMD event may be substantially larger if it

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scale events, such as voltage and reactive power fluctuations, local disruption of service, limited equipment failure, and potential voltage instability resulting in uncontrolled cascading of the bulk power system.").

[15] While disagreements exist as to the likely severity of transformer damage from GMDs compared with the likelihood of voltage collapse due to increased reactive power absorption arising from GMDs, there appears to be a consensus that GMDs can cause at least some damage to Bulk-Power System transformers. *See*, *e.g.*, Comments of the North American Electric Reliability Corporation, Docket No. AD12-13-000, at 5 (filed May 21, 2012) ("Though the most likely result is voltage collapse, the GMD Task Force members agreed that, depending on the transformer health, design, geology and geomagnetic latitude, geomagnetic induced current flows can result in transformer loss-of-life, and may ultimately result in the failure of some transformers.").

[16] *Oak Ridge Study 319 Report* at pages 4-1, 4-3 ("The recovery could plausibly extend into months in many parts of the impacted regions … These multi-ton apparatus [transformers] generally cannot be repaired in the field, and if damaged in this manner, they need to be replaced with new units, which have manufacture lead times of 12 months or more in the world market."); NERC Interim GMD Report at iv ("[R]estoration times for system collapse due to voltage instability would be a matter of hours to days, while replacing transformers requires long-lead times (a number of months) to replace or move spares into place, unless they are in a nearby location. Therefore, the failure of a large numbers [sic] of transformers would have considerable impacts on portions of the system.").

[17] *Oak Ridge Study 319 Report* at page 3-22.

[18] *Id*. at page 1-14, Tables 4-1, 4-2, 4-3 (listing numbers of at-risk transformer).

occurred at lower latitudes.[19] Estimates prepared by the National Research Council of the National Academies concluded that these events have the potential to cause wide-spread, long-term losses with economic costs to the United States estimated at $1-2 trillion and a recovery time of four to ten years.[20] The NERC Interim GMD Report concluded, on the other hand, that the worst-case scenario is "voltage instability and subsequent voltage collapse," and cites as an example the 1989 Hydro-Québec blackout.[21] While the conclusions of these reports differ significantly, our proposed action is warranted by even the lesser consequence of a projected widespread blackout without long-term, significant damage to the Bulk-Power System. Taking steps to prevent such blackouts is consistent with maintaining the reliable operation of the Bulk-Power System.[22]

6. Given the potentially severe, wide-spread impact to the reliable operation of the Bulk-Power System from GMD events and the absence of existing Reliability Standards to address it, the Commission proposes to direct the ERO to file with the Commission for

[19] *Id.* at pages 3-25, 3-26.

[20] National Research Council of the National Academies, *Severe Space Weather Events—Understanding Societal and Economic Impacts: A Workshop Report* at 4 (2008) (*NAS Workshop Report*), *available at* http://www.nap.edu/catalog/12507.html.

[21] NERC Interim GMD Report at 69.

[22] 16 U.S.C. 824o(a)(4) ("The term 'reliable operation' means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.").

approval Reliability Standards that address this reliability gap. In proposing to address the risks posed by GMDs in two stages, the Commission finds that there are Reliability Standards that the ERO can develop and file quickly (i.e., requiring GMD operational procedures) to mitigate the effects of GMDs while it develops other Reliability Standards that require owners and operators of the Bulk-Power System to assess the potential impact of GMDs on Bulk-Power System equipment and the Bulk-Power System as a whole. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs indentified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit.[23]

7. We recognize that, depending on the results of the initial and on-going assessments that would be required under this proposed rule, there could be substantial costs associated with some measures to protect against damage to the Bulk-Power System

[23] *See infra* PP 34-36.

from GMDs.[24] In determining that it is appropriate to issue this proposed rule, however, we have compared such costs against the societal harms, including the potential costs of equipment damage or prolonged blackouts, that could result from taking no action.[25]

I. Background

A. Section 215 and Mandatory Reliability Standards

8. Section 215 of the FPA requires the Commission to certify an ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.[26] Once approved, the Reliability Standards may be enforced in the United States by the ERO, subject to Commission oversight, or by the Commission independently.

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[24] For example, estimates for installing blocking devices on transformers range from $100,000 to $500,000 for each affected transformer. *See* Foundation for Resilient Societies, Comments on Advance Notice of Proposed Rulemaking (ANPR) of the Nuclear Regulatory Commission Relating to the Prevention and Mitigation of Station Blackout, filed in Docket No. AD12-13-000, at 13 (May 4, 2012) (citing $500,000 installed costs per transformer); MITRE Corp., Impacts of Severe Space Weather on the Electric Grid, at 66 (November 2011) (citing $100,000 cost for neutral-current-blocking-capacitors per transformer), *available at* http://www.fas.org/irp/agency/dod/jason/spaceweather.pdf.

[25] For example the estimated total cost of the August 2003 four-day blackout in the United States is between $4 billion and $10 billion, with the Department of Energy calculating the total cost to be $6 billion. Electricity Consumers Resource Council, The Economic Impacts of the August 2003 Blackout, *available at* http://www.elcon.org/Documents/EconomicImpactsOfAugust2003Blackout.pdf. *See also supra* P 5 (citing estimates by the National Research Council of the National Academies of potentially $1-2 trillion in economic costs from a severe GMD event).

[26] 16 U.S.C. § 824o (2006).

9. Pursuant to section 215(d)(5) of the FPA, the Commission has the authority, upon its own motion or upon complaint, to order the ERO to submit to the Commission a proposed Reliability Standard or a modification to a Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Reliability Standard appropriate to carry out section 215 of the FPA.[27]

B. Studies of GMD Events on the Bulk-Power System

10. The impact of GMDs on the Bulk-Power System has been evaluated in several government-sponsored studies and NERC reports. The EMP Commission issued reports assessing the threat to the United States from Electromagnetic Pulse (EMP) attack in 2004 and 2008, which also addressed the effects of geomagnetic storms on the electric power infrastructure.[28] The NAS Workshop Report addressing the impact of severe space weather events was released in 2008. The Oak Ridge National Laboratory issued the Oak Ridge Study on the effects of electromagnetic pulses on the Bulk-Power System in January 2010. The NERC HILF Report on high-impact, low-frequency risks to the Bulk-Power System was issued in June 2010.[29] In February 2012, NERC issued the NERC Interim GMD Report evaluating the effects of GMDs on the Bulk-Power System.

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[27] 16 U.S.C. 824o(d)(5); 18 CFR 39.6(f) (2012).

[28] These reports are accessible at the Commission to Assess the Threat to the United States from Electromagnetic Pulse (EMP) Attack website at http://www.empcommission.org/.

[29] The HILF Report was prepared by NERC, Department of Energy, and a steering committee comprised of industry and risk experts and was approved by the NERC Board of Trustees on May 17, 2010. *HILF Report* at 2.

11. The Commission conducted a staff-led Technical Conference on April 30, 2012 to discuss the effects of GMDs on the reliable operation of the Bulk-Power System. NERC, government agencies, industry stakeholders, and other interested entities attended the Technical Conference and submitted post-Technical Conference comments.

C. Effects of GMD Events on the Bulk-Power System

12. The interaction of the Earth's magnetic field and solar events can cause low frequency GICs to flow along the surface of the Earth and in the oceans. Reliability issues arise when GICs enter the Bulk-Power System from the Earth. Since many Bulk-Power System transformers are grounded, the GIC appears as electrical current to the Bulk-Power System and flows through the ground connection and conductors, such as transformers and transmission lines.[30]

13. GICs can cause transformer cores to become "saturated," resulting in loss of reactive power (VARs), the introduction of harmonic distortions, and possible physical damage to the transformer.[31] GICs enter the Bulk-Power System through the grounded neutrals of transformers and are responsible for forcing their metal cores into saturation.[32]

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[30] Oak Ridge National Laboratory, *Electromagnetic Pulse: Effects on the U.S. Power Grid (Meta-R-322)* at page 1-1 (January 2010) (*Oak Ridge Study 322 Report*), *available at* http://www.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-322.pdf.

[31] *HILF Report* 70-71. Harmonics are currents or voltages with frequencies that are integer multiples of the fundamental power frequency (i.e., 60 Hz in the United States). *See* Northeast Power Coordinating Council, Inc. Glossary of Terms, *available at* https://www.npcc.org/Standards/Directories/Glossary%20of%20Terms.pdf. They can cause overcurrent relays to automatically trip components (e.g., capacitor banks and static VAR compensators) from service. *HILF Report* at 71. Automatic removal of such components can further exacerbate system voltages already reduced by the GIC-related

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A primary effect of saturation is the potential for transformer damage through the overheating of internal components.[33] Saturation is also responsible for secondary effects, such as the production of harmonics that are not present during normal Bulk-Power System operation and for substantially increasing the transformer's absorption of reactive power from the system, thus requiring significant amounts of additional voltage support to compensate for reactive power absorption. Harmonic production and reactive power absorption may interfere with normal system operations creating secondary effects on other Bulk-Power System facilities. These primary and secondary effects can occur almost simultaneously over a large geographic area, resulting in a multiple contingency outage that has the potential to cascade across the Bulk-Power System.[34]

14. The Oak Ridge Study identified factors that determine the severity of GMD events, including: (1) location and strength of the underlying solar event; (2) ground conductivity in the affected locations (i.e., the geology of the location); (3) orientation of

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absorption of reactive power.

[32] *Oak Ridge Study 322 Report* at pages 1-1, 7-11.

[33] *HILF Report* at 70 ("Transformers experience excessive levels of internal heating brought on by stray flux when GICs cause the transformer's magnetic core to saturate and spill flux outside the normal core steel magnetic circuit. Previous well-documented cases have noted heating failures that caused melting and burn-through of large-amperage copper windings and leads in these transformers (Figure 9)."); *Oak Ridge Study 319 Report* at page 2-29 ("Also of note from this particular [March 1989] storm is strong evidence that GIC-induced half-cycle saturation of transformers can indeed produce enough heat to severely damage or even destroy exposed large power transformers.").

[34] *HILF Report* at 71-72.

the transmission lines; (4) length of transmission lines; and (5) grid construction.[35] A solar disturbance can cause near-simultaneous, multi-point failures that can trigger collapse of the Bulk-Power System.[36]

II. Discussion

15. As discussed below, the Commission finds that there is a gap in the Reliability Standards regarding GMDs. Therefore, in order to carry out section 215 of the FPA, the Commission proposes to direct the ERO to develop and file for approval Reliability Standards that address the potentially severe, wide-spread impact of GMD events on the reliable operation of the Bulk-Power System.

16. We propose that the ERO develop and file the GMD Reliability Standards in two stages. In the first stage, within 90 days of the effective date of a final rule in this proceeding, the Commission proposes to direct NERC to file one or more Reliability Standards that require owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System. In the second stage, the Commission proposes to direct NERC to file one or more Reliability Standards, within six months of the effective date of a final rule in this proceeding, that require owners and operators of the Bulk-Power System to assess the impact of GMDs on Bulk-Power System equipment

[35] *Oak Ridge Study 319 Report* at page 2-5.

[36] *Id.* at pages 4-1, 4-2. One example cited in the Oak Ridge Study is the March 13, 1989 solar disturbance that triggered the collapse of the Hydro-Québec power grid, which went from normal to a situation where it sustained seven contingencies in an elapsed time of 57 seconds. *Id.*

and the Bulk-Power System as a whole. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs indentified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit.[37]

17. In proposing to direct the ERO to submit Reliability Standards that address the impact of GMD events on the reliable operation of the Bulk-Power System, we are not proposing specific requirements or otherwise pre-judging what the ERO may eventually submit. Instead, we identify concerns that we believe should be addressed in any GMD Reliability Standards. We expect the ERO to support its proposed Reliability Standards and explain how they address the Commission's concerns.

[37] The second stage Reliability Standards would not require owners and operators of the Bulk-Power System to protect the Bulk-Power System beyond what is found to be required based on the initial and ongoing assessments.

A. Reliability Standards Requiring Operational Procedures

18. Requiring operational procedures, while not a complete solution, constitutes a first step to addressing the GMD reliability gap because they can be implemented relatively quickly.[38] The Commission does not propose to require the ERO or owners and operators of the Bulk-Power System to adopt any particular operational procedures. Owners and operators of the Bulk-Power System are the most familiar with the equipment and system configurations. Accordingly, we propose that the ERO file one or more Reliability Standards requiring owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System based on the following guidance.

19. Operational procedures may help alleviate abnormal system conditions due to transformer absorption of reactive power during GMD events, helping to stabilize system voltage swings, and may potentially isolate some equipment from being damaged or misoperated. The NERC Interim GMD Report identifies examples of operational procedures to mitigate GMD events (i.e., the effects of GICs), including: reduction of equipment loading (e.g., by starting off-line generation), unloading the reactive load of operating generation, reductions of system voltage, and system and/or equipment

[38] NERC Interim GMD Report at 79 ("Operating procedures are the quickest way to put in place actions that can mitigate the adverse effects of GIC on system reliability … Both system operating and transmission owner organizations need to have appropriate procedures and training in place.").

isolation through reconfiguration of the transmission system.[39] Some entities already have operational procedures to mitigate the effect of GICs on the Bulk-Power System utilizing system resources.[40] The Commission expects that the ERO and owners and operators of the Bulk-Power System will draw on industry's experience in developing and implementing existing operational procedures. Given that experience, we propose to direct NERC to file, within 90 days of the effective date of a final rule in this proceeding, proposed Reliability Standards that require the development and implementation of operational procedures. While this deadline is aggressive, mandatory and enforceable Reliability Standards requiring owners and operators to implement operational procedures should be established quickly to afford some level of uniform protection to the Bulk-Power System against GMD events. As discussed above, the impact of GMDs on the Bulk-Power System has been studied extensively for many years, laying the foundation for the prompt development of these first stage Reliability Standards. Moreover, the fact that operational procedures are already in place in some areas should allow for faster development and implementation of these Reliability Standards.

20. While the proposed Reliability Standards should not necessarily specify what operational procedures must be adopted, the ERO should give owners and operators of

[39] NERC Interim GMD Report at 80-81.

[40] *See*, *e.g.*, PJM Interconnection, L.L.C., Manual 13: Emergency Operations at 47, *available at* http://www.pjm.com/~/media/documents/manuals/m13.ashx; Northeast Power Coordinating Council, Inc., Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems, *available at* https://www.npcc.org/Standards/Procedures/c-15.pdf.

the Bulk-Power System guidance as to what procedures have been or are expected to be effective in mitigating the effects of GMDs consistent with the reliable operation of the Bulk-Power System. Moreover, the proposed Reliability Standards should address the coordination of operational procedures among responsible entities across regions.[41] Since there could be potential equipment damage resulting from a GMD event, the proposed Reliability Standards should also address operational procedures for restoring GMD-impacted portions of the Bulk-Power System that take into account the potential for equipment that is damaged or out-of-service for an extended period of time.

21. We do not propose to direct a specific implementation schedule for the proposed Reliability Standards, but the Commission encourages the ERO to require owners and operators of the Bulk-Power System to implement the required operational procedures 90 days after Commission approval of the Reliability Standards. Following implementation, the Commission proposes to require NERC to provide periodic reports assessing the effectiveness of the operational procedures in mitigating the effects of GMD events. In addition, NERC should periodically review the required operational procedures and recommend to owners and operators that they incorporate lessons-learned and new research findings.

22. In addition to developing Reliability Standards that require operational procedures during the first stage, the Commission also proposes to accept aspects of the "Initial

[41] NERC Interim GMD Report at 79 ("The [operating] procedures of these organizations need to be coordinated with each other and with their neighboring organizations.").

Actions" proposal set forth in NERC's May 21, 2012 post-Technical Conference comments. Specifically, NERC proposed to "identify facilities most at-risk from severe geomagnetic disturbance" and to "conduct wide-area geomagnetic disturbance vulnerability assessment."[42] As noted in NERC's comments regarding the vulnerability assessments, special attention would be given to evaluating critical transformers (e.g., step-up transformers at large generating facilities). We agree with NERC that critical Bulk-Power System facilities should be evaluated for GMD vulnerability as an initial action. In addition, as part of the initial action, special attention should be given to those Bulk-Power System facilities that provide service to critical and priority loads.[43] The Commission, therefore, proposes to direct NERC to conduct this "initial action" simultaneously with the development and implementation of the first stage GMD Reliability Standards. The Commission seeks comment from NERC and other interested entities on all aspects of this proposal.

[42] NERC Comments at 8-9 ("As the first step in identifying the risk of geomagnetic disturbance to the bulk power system, NERC intends to complete a system-wide vulnerability assessment … special attention will be given to the evaluation of critical transformers, such as generator step-up units at large generating facilities … a high level review will be conducted to identify and classify the at-risk population based on existing peer-reviewed research. This assessment will be based on a high level screening approach that will include transformer design, condition, geology and geomagnetic location.").

[43] The NERC Severe Impact Resilience Task Force identified critical and priority loads in a report. *See* Severe Impact Resilience: Considerations and Recommendations at 26 (Accepted by NERC Board of Trustees on May 9, 2012), *available at* http://www.nerc.com/docs/oc/sirtf/SIRTF_Final_May_9_2012-Board_Accepted.pdf.

B. Second Stage Reliability Standards

23. To address GMDs comprehensively, the Commission proposes to direct NERC to develop, in a second stage, Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going assessments of the potential impact of GMDs on Bulk-Power System equipment and on the Bulk-Power System as a whole. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs indentified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit. While the Commission proposes to direct the ERO to submit the proposed second stage Reliability Standards within six months of the effective date of a final rule in this proceeding, the Commission seeks comment on the feasibility of a six-month deadline.

24. We propose to direct the filing of these second stage GMD Reliability Standards because of two concerns with relying on operational procedures alone: (1) owners and operators of the Bulk-Power System may not have enough time to initiate effective

operating procedures after being warned of a GMD event; and (2) operational procedures may not prevent permanent damage to Bulk-Power System equipment.[44] Current GMD forecasting methods provide limited time for operators to react once a GMD warning is issued.[45] Even with enough time to react, the Oak Ridge Study found that, given a large enough GMD event, operational procedures are unlikely to provide the substantial levels of GIC reduction needed to limit the potential for permanent damage to transformers.[46] The Oak Ridge Study and the HILF Report also found that widespread damage to Bulk-Power System transformers could result in prolonged outages.[47]

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[44] NERC Interim GMD Report at 10 ("These warning can be received as short as 30 minutes before the onset of an impending geomagnetic storm."). At the April 30, 2012 Technical Conference, Mr. Murtagh, Program Coordinator at the National Oceanic and Atmospheric Administration's Space Weather Prediction Center, stated that a warning is issued when a GMD event reaches the NASA Advanced Composition Explorer (ACE) satellite and at that point, in some cases, it could be 20 or 30 minutes before the event reaches the Earth's magnetic field. April 30, 2012 Technical Conference Tr. 170:5-22 (Murtagh).

[45] Mr. Pugh, from the U.S. Department of Homeland Security's Interagency Programs Office Science & Technology Directorate, stated that the operators in the 1989 Hydro-Québec blackout only had 90 seconds to react, which was insufficient to "prevent a massive blackout and significant equipment damage." April 30, 2012 Technical Conference Tr. 12:4-7 (Pugh).

[46] *Oak Ridge Study 322 Report* at pages ix and 1-1.

[47] *HILF Report* at 12 ("The physical damage of certain system components (e.g. extra-high-voltage transformers) on a large scale, as could be effected by any of these threats, could result in prolonged outages as procurement cycles for these components range from months to years."); *Oak Ridge Study 319 Report* at pages 2-33, 2-34 ("An especially large storm or GIC event could plausibly create the potential for widespread failure of many exposed transformers and hamper rapid restoration capabilities. In extreme cases, where replacements may take months, a situation may exist where the demand for electric service can only be partially supplied, raising the prospect of rationing and rotating blackouts to regions that are unable to be fully served.").

25. We recognize that the NERC Interim GMD Report concludes that a prolonged blackout due to extensive damage to Bulk-Power System transformers is less likely than voltage instability due to increased reactive power consumption and loss of reactive power support, which can lead to blackouts like the 1989 Hydro-Québec event.[48] The Commission's proposed two-stage approach recognizes this difference by focusing first on the development of Reliability Standards requiring operational procedures in a relatively short time frame. The Commission proposes to give NERC and owners and operators of the Bulk-Power System more time to perform, in the second stage, initial and on-going assessments. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs indentified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit. Moreover, although the NOPR proposes that the second stage

[48] NERC Interim GMD Report at vi.

Reliability Standards be filed within six months of the effective date of the final rule, we seek comment on the feasibility of that deadline.

26. Below, we offer guidance on the assessments of Bulk-Power System vulnerability to GMDs and potential measures for automatically protecting critical or vulnerable components. In addition, recognizing the potential for substantial investments of time and resources to implement these Reliability Standards, we offer guidance on an implementation schedule, which will likely consist of an extended, multi-phase process. The Commission seeks comment from NERC and other interested entities on all aspects of this proposal.

1. GMD Vulnerability Assessments of the Bulk-Power System

27. The Commission proposes to direct the ERO to develop Reliability Standards that require owners and operators of the Bulk-Power System to conduct vulnerability assessments to determine how critical or vulnerable Bulk-Power System components react to simulated GICs of varying intensities.[49] The Commission proposes to direct the ERO to consider the following parameters as it develops the Reliability Standards.[50]

[49] To accurately simulate the impact of GMDs on the Bulk-Power System, the assessments should consider the impact of GICs that may enter the system through transformers that are not treated as part of the bulk electric system and any impact that the non-bulk electric system transformers may have on the reliability of the Bulk-Power System. We do not propose, however, that equipment falling outside of our jurisdiction would be required to be protected under the proposed Reliability Standard.

[50] The vulnerability assessments in the second phase Reliability Standards are distinct from the "initial action" evaluations, discussed above, which NERC proposed to do and we propose to have NERC conduct simultaneous with the development and implementation of the first phase Reliability Standards. We expect, however, that the

(continued…)

28. First, the Reliability Standards should contain uniform evaluation criteria for owners and operators to follow when conducting their assessments. As the Commission noted with respect to other reliability assessments, uniformity increases the accuracy of transmission system reliability assessments and consequently enhances overall reliability.[51]

29. Second, the assessments should, through studies and simulations, evaluate the primary and secondary effects of GICs on Bulk-Power System transformers, including the effects of GICs originating from and passing to other regions.

30. Third, the assessments should evaluate the effects of GICs on other Bulk-Power System equipment, system operations, and system stability, including the anticipated loss of critical or vulnerable devices or elements resulting from GIC-related issues.[52]

31. Fourth, in conjunction with assessments by owners and operators of their own Bulk-Power System components, wide-area or Regional assessments of GIC impacts should be performed. A severe GMD event can cause simultaneous stresses at multiple

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analyses performed in the "initial action" evaluations will be used to quickly identify and protect the most critical and vulnerable Bulk-Power System components once the second stage Reliability Standards become effective.

[51] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1298, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[52] The Oak Ridge Study assessment included GMD modeling, simulation and review of storm impacts, power grid GIC flows and reactive power demands, transformer heating and risk of potential damage to transformers. *See generally Oak Ridge Study 319 Report*.

locations on the Bulk-Power System, potentially resulting in a multiple-outage event.[53] In predicting GIC flows, it is necessary to take into consideration the network topology as an integrated whole (i.e., on a wide-area basis).[54]

32. Fifth, the assessments should be periodically updated, taking into account new facilities, modifications to existing facilities, and new information, including new research on GMDs, to determine whether there are resulting changes in GMD impacts that require modifications to Bulk-Power System mitigation schemes.

33. The Commission seeks comments from NERC and other interested entities on all aspects of this proposal.

2. Automatic GIC Blocking for Critical or Vulnerable Bulk-Power System Components

34. While we do not propose to require a particular solution in the second stage Reliability Standards to address GMDs, we expect that some assessments will demonstrate that automatic blocking is necessary in some instances. The Commission, above, proposes to direct the ERO to develop Reliability Standards that require owners and operators of the Bulk-Power System to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. Automatic blocking measures address the major concerns with relying exclusively on operational procedures to mitigate GMDs (i.e., the

[53] *Oak Ridge Study 319 Report* at pages A1-1, A1-2.

[54] *Id.* at page 1-17.

short period of time to react to a GMD event and the potential consequences of not reacting fast enough). Blocking can prevent the flow of GICs through power transformers and the Bulk-Power System.[55] Eliminating GICs in transformers prevents transformer core saturation and, thus, mitigates or prevents the effects of GMDs on the Bulk-Power System (i.e., transformer overheating, reactive power absorption, and harmonic generation).

35. The Commission does not propose to direct the ERO to require a particular automatic blocking technology, where blocking is necessary. Instead, the Commission proposes to direct the ERO to identify in the proposed Reliability Standards what would constitute appropriate automatic blocking measures. In defining what is an appropriate blocking measure, the ERO should address: (1) its feasibility and effectiveness; and (2) its ability to operate without adversely impacting the reliable operation of the Bulk-Power System. The Commission proposes that the Reliability Standards should include a means by which the ERO can verify that selected blocking measures are appropriate.

36. The use of automatic blocking devices, such as transmission line series capacitors and transformer neutral blocking, are possible measures.[56] These devices block or reduce the flow of GIC in a power grid.[57] Although not a means for blocking GICs, another possible option is to improve the "withstand" capability of Bulk-Power System

[55] NERC Interim GMD Report at 73.

[56] *Oak Ridge Study 322 Report* at ix-x.

[57] *Id.*

components. The "withstand" capability, in this context, refers to a component's ability to withstand stresses imposed by GICs before suffering damage, but it does not prevent GICs from affecting the rest of the Bulk-Power System (e.g., it does not prevent the secondary effects of harmonics or increased reactive power consumption).[58] The ERO should consider whether the reliability goals of the proposed Reliability Standards can be achieved by a combination of automatic protection measures, including, for example, some combination of automatic blocking and improved "withstand" capability. In any event, the measures must be adequate to protect the reliability of the Bulk-Power System against the risks identified in the assessments.

37. The Commission seeks comments from NERC and other interested entities on all aspects of this proposal.

3. Implementation Schedule

38. The second stage Reliability Standards will likely require an extended, multi-phase implementation period given the time needed to conduct the required assessments and the time and cost of installing any required automatic protection measures. Although the Commission does not propose to direct the ERO to develop a specific implementation plan, we believe it would be appropriate for the proposed Reliability Standard to include an implementation schedule that requires owners and operators of the Bulk-Power System to prioritize implementation so that components considered vital to the reliable

[58] NERC Interim GMD Report at 67.

operation of the Bulk-Power System are provided with any necessary automatic protection measures in the earliest phase of the plan.[59]

39. The Commission seeks comments from NERC and other interested entities on an implementation plan.

III. Information Collection Statement

40. The Office of Management and Budget (OMB) regulations require approval of certain information collection requirements imposed by agency rules. Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of an agency rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. The Paperwork Reduction Act (PRA) requires each federal agency to seek and obtain OMB approval before undertaking a collection of information directed to ten or more persons, or contained in a rule of general applicability.

41. The Commission is submitting these reporting requirements to OMB for its review and approval under section 3507(d) of the PRA. Comments are solicited on the Commission's need for this information, whether the information will have practical utility, ways to enhance the quality, utility, and clarity of the information to be collected,

[59] For example, critical Bulk-Power System equipment identified by NERC in the first stage "initial actions" assessments, discussed previously, should be protected in the earliest phase of the implementation plan.

and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

42. The Public Reporting Burden and cost related to the proposed rule in Docket No. RM12-22-000 are covered by, and already included in, the existing FERC-725, Certification of Electric Reliability Organization; Procedures for Electric Reliability (OMB Control No. 1902-0225). FERC-725 includes the ERO's overall responsibility for developing Reliability Standards, such as the Reliability Standards for Geomagnetic Disturbances.

43. Internal review: The Commission has reviewed the proposed changes and has determined that the changes are necessary to ensure the reliability and integrity of the Nation's Bulk-Power System.

44. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, Phone: (202) 502-8663, fax: (202) 273-0873]. Comments on the requirements of this rule may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at oira_submission@omb.eop.gov. Please reference OMB Control No. 1902-0225, FERC-725 and the docket number of this proposed rulemaking in your submission.

IV. Environmental Analysis

45. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[60] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[61] The actions proposed here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

46. The Regulatory Flexibility Act of 1980 (RFA)[62] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities.

47. By only proposing to direct NERC, the Commission-certified ERO, to develop GMD Reliability Standards, this Notice of Proposed Rulemaking will not have a significant or substantial impact on entities other than NERC. The ERO develops and files with the Commission for approval Reliability Standards affecting the Bulk-Power System, which represents: (a) a total electricity demand of 830 gigawatts (830,000

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[60] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

[61] 18 CFR 380.4(a)(2)(ii).

[62] 5 U.S.C. 601-612.

megawatts) and (b) more than $1 trillion worth of assets. Therefore, the Commission certifies that this Notice of Proposed Rulemaking will not have a significant economic impact on a substantial number of small entities.

48. Any Reliability Standards proposed by NERC in compliance with this rulemaking will be considered by the Commission in future proceedings. As part of any future proceedings, the Commission will make determinations pertaining to the Regulatory Flexibility Act based on the content of the Reliability Standards proposed by NERC.

VI. Comment Procedures

49. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [**INSERT DATE 60 days after publication in the FEDERAL REGISTER**]. Comments must refer to Docket No. RM12-22-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

50. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

51. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426.

52. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

53. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

54. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

55. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference

Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission.

Kimberly D. Bose,
Secretary.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Statement

Response to FERC's Proposed Rulemaking on Vegetation Management, Geomagnetic Disturbance Standards

October 18, 2012

WASHINGTON, DC -- The Federal Energy Regulatory Commission issued a notice of proposed rulemaking today proposing to approve the North American Electric Reliability Corporation's vegetation management standard (FAC-003-2). In separate action, the FERC proposed to direct NERC to develop standards that address geomagnetic disturbances and their impacts on the grid.

"The proposed approval of the results-based vegetation management standard is an important recognition of NERC's efforts on addressing this issue," said Gerry Cauley, president and chief executive officer at NERC. "The proposed rulemaking on geomagnetic disturbances provides a framework to address the current vulnerability, and to factor in the scientific and engineering analysis necessary to understand this complex issue."

The proposed rulemaking on geomagnetic disturbances outlines a two-step process for the industry to, first, develop and implement operational procedures to mitigate effects of solar storms, reflecting many of the recommendations outlined in NERC's 2012 geomagnetic disturbance report and, second, to conduct assessments and implement strategies based on those assessments to protect the bulk power system from geomagnetic disturbances.

NERC has placed a high priority on the vegetation management standard and on identifying effects of geomagnetic disturbances on the bulk power system, and looks forward to working with FERC and the industry to continue our efforts to safeguard the grid.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)** **)**	**Docket No. RM09-13-_____**

NOTICE OF WITHDRAWAL OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION OF BAL-004-1 – TIME ERROR CORRECTION

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October 24, 2012

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)** **)**	**Docket No. RM09-13-____**

NOTICE OF WITHDRAWAL OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION OF BAL-004-1 – TIME ERROR CORRECTION

Pursuant to Rule 216 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.216 (2012), the North American Electric Reliability Corporation ("NERC") hereby submits this Notice of Withdrawal of its NERC's March 11, 2009, Petition for Approval of the BAL-004-1 Time Error Correction Reliability Standard ("Petition"). BAL-004-0 is currently effective and is unaltered by the submission of this Notice.

I. BACKGROUND

A. Time Error Correction Generally

As the Commission has noted, Time Error occurs when a synchronous Interconnection operates at a frequency that is different from the Interconnection's Scheduled Frequency.[1] Interconnections control to 60 Hz (60 cycles per second); however, the control is imperfect and over time will result in the average frequency being either above 60 Hz or below 60 Hz. This discrepancy between actual frequency and Scheduled Frequency results from an imbalance between generation and interchange and load and losses, which also results in Inadvertent Interchange.[2] Time Error Correction is

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[1] *Time Error Correction Reliability Standar*d, 130 FERC ¶ 61,201 (2010).

[2] Inadvertent Interchange occurs when unplanned energy transfers cross Balancing Authority boundaries, typically where a Balancing Authority experiences an operational problem that prevents its net

the procedure Reliability Coordinators and Balancing Authorities follow to reduce Time Error and regulate the average frequency closer to 60 Hz. The Time Error Correction Reliability Standard, BAL-004-0, sets forth the process that Reliability Coordinators and Balancing Authorities follow to offset their Scheduled Frequency to reliably correct for the accumulated Time Error. The efficiency of Time Error Corrections is determined by the participation of all Balancing Authorities within the Interconnection. Coordination and oversight by all Balancing Authorities and Reliability Coordinators is necessary to ensure that Time Error Corrections are performed reliably.

B. Proposed Reliability Standard BAL-004-1

BAL-004-0, Requirement R1 currently states that only a Reliability Coordinator is eligible to serve as an Interconnection Time Monitor, and that the NERC Operating Committee shall designate a single Reliability Coordinator in each Interconnection to serve as Interconnection Time Monitor. The proposed changes in BAL-004-1 would remove the requirement that the NERC Operating Committee designate Interconnection Time Monitors. The proposed change would vest authority for designating Interconnection Time Monitors with the NERC Board of Trustees, based on NERC Operating Committee review and recommendation. As NERC noted in its Petition (at p. 10), BAL-004-1 was intended to maintain the *status quo* by allowing a Reliability Coordinator to continue to be available to serve in the voluntary role of Interconnection Time Monitor. As explained below, NERC has determined that these proposed changes to BAL-004-1 are unnecessary and therefore, NERC is providing notice of its withdrawal of the Petition for approval of BAL-004-1.

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actual interchange of energy from matching its net scheduled interchange with other Balancing Authorities within the Interconnection.

C. Procedural History

The Commission approved the current Time Error Correction Reliability Standard, BAL-004-0, on March 16, 2007, as part of Order No. 693.[3] The NERC Operating Committee submitted a Standard Authorization Request ("SAR") to the NERC Standards Committee on July 11, 2007, proposing changes to BAL-004-0. The Operating Committee requested that the Standards Committee use the "Urgent Action" process in addressing the proposed revisions. At its September 11, 2007 meeting, the Standards Committee determined to post the SAR and proposed standard changes using the Urgent Action process, stating that the potential loss of a willing Reliability Coordinator to serve as the Interconnection Time Monitor justified use of the Urgent Access process. The BAL-004-1 standard passed with 97.45 percent of the 157 ballot pool participants voting, resulting in a weighted segment approval of 94.10 percent. The NERC Board of Trustees approved the revised Reliability Standard on March 26, 2008.

On March 11, 2009, NERC filed a request for Commission approval of the proposed BAL-004-1 Reliability Standard. In response, the Commission issued a Notice of Proposed Rulemaking ("NOPR") on March 18, 2010, that proposed to remand the standard and direct NERC to make specific changes to address Commission concerns.[4] Specifically, the Commission proposed to direct NERC, on remand, to modify its proposed changes to Requirement R2 to (1) indicate that the Time Monitor, designated according to a process described in a Commission-approved document, is responsible for initiating or termination a Time Error Correction in a reliable manner; and (2) explain the

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[3] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[4] *Time Error Correction Reliability Standar*d, 130 FERC ¶ 61,201 (2010).

circumstances under which the Time Monitor should start or end a Time Error Correction.[5]

NERC and several other entities submitted comments to the Commission regarding the NOPR. General support for the Commission's NOPR proposal seemed lacking, as reflected in comments from NERC, the Edison Electric Institute, the Midwest Independent Transmission System Operator, Inc., and the ISO/RTO Council. No entity submitted comments in direct support of the NOPR's proposal to remand BAL-004-1.

On August 20, 2010, NERC submitted a Motion to Defer Action on the BAL-004-1 Petition. In the motion, NERC noted that ongoing testing and analysis of Time Error Correction might lead to NERC's withdrawal of the request for approval of BAL-004-1 and the retirement of BAL-004-0, and that issuing a final rule would be premature at this stage in the process. NERC requested that the Commission defer action until August 20, 2011. NERC also stated that it would submit a status report six months from the date of the motion. On February 22, 2011, NERC filed an informational status report, fulfilling that commitment.

On August 11, 2011, NERC filed a Motion to Further Defer Action on NERC's Petition for Approval of BAL-004-1. On August 16, 2012, the NERC Board of Trustees rescinded its approval of BAL-004-1 and directed NERC Staff to withdraw the petition submitted to the Commission requesting approval of BAL-004-1. BAL-004-0 remains in effect and is unaffected by the submission of this Notice.

[5] *Id.* at P 25.

II. NOTICES AND COMMUNICATION

Notices and communications with respect to this filing may be addressed to the following:[6]

Gerald W. Cauley
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III. SUPPORT FOR NOTICE OF WITHDRAWAL OF BAL-004-1

NERC and its stakeholders performed significant outreach to entities both inside and outside the electric utility industry to determine if Manual Time Error Correction could be eliminated with minimal harm. While it was clear that eliminating Time Error Corrections is unlikely to have a negative impact on reliability that was insurmountable, it also became clear that the potential for other problems was largely undefined and not well understood. Following extensive discussion and debate over several months, it was ultimately determined by the NERC Operating Committee at its March 6-7, 2012, meeting that NERC should discontinue its effort to eliminate Manual Time Error Corrections.

[6] Persons to be included on the Commission's service list are indicated with an asterisk. NERC requests waiver of 18 C.F.R. § 385.203(b) to permit the inclusion of more than two people on the service list.

When considering the original reasons enumerated above for creating BAL-004-1, NERC has learned that those concerns may no longer be as acute as originally envisioned.

- To date, no Interconnection Time Monitor has incurred a violation of BAL-004-0. The need to modify the standard to address this concern would appear to be less severe than originally envisioned.
- Upon further review, because the NERC Operating Committee is not a registered entity, there is no potential for compliance actions against the Operating Committee. As such, the statement regarding the role of the Operating Committee in selecting the Interconnection Time Monitor should be considered for informational purposes only. There is no need to change the standard to address this concern, other than for purposes of clarification.
- The Commission's prior approval of the BAL-004-0 standard indicates that there is not a conflict in requiring that entities adhere to the NAESB business practices associated with Time Error Correction, as is provided in Requirement R2. In the proceedings under FERC Docket RM06-16-000 (Order No. 693), no entities expressed an objection to Requirement R2. While elimination of the reference to NAESB business practices may still be considered on a going-forward basis, this alone is insufficient justification to pursue a change to the standard at this time.

Additionally:

- BAL-004-0 remains in effect, and has been in effect since 2007.
- Manual Time Error Correction is no longer expected to be eliminated.

- The Reliability Standards Development Plan already includes a project to address modifications of BAL-004. Based on the prioritization established during the development of the 2012-2014 Reliability Standards Development Plan, Project 2010-14.2 Phase 2 of Balancing Authority Reliability-based Controls: Time Error, AGC, and Inadvertent, is expected to begin in 2013.

For these reasons, NERC hereby submits this Notice of Withdrawal of NERC's March 11, 2009, Petition for Approval of the BAL-004-1. As noted above, BAL-004-0 remains in effect and is unaltered by the submission of this Notice.

IV. CONCLUSION

NERC respectfully requests that the Commission withdraw NERC's petition for approval of BAL-004-1.

Respectfully submitted,

/s/ Stacey Tyrewala

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 24th day of October, 2012.

/s/ Stacey Tyrewala
Stacey Tyrewala
Attorney for North American Electric Reliability Corporation

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

North American Electric Reliability Corporation
Docket No. RR12-12-000

Issued: October 24, 2012

Schiff Hardin LLP
1666 K Street, N.W., Suite 300
Washington, DC 20036-4390

Attention: Owen E. MacBride
Attorney for North American Electric Reliability Corporation

Reference: Amendments to Delegation Agreement with Reliability*First* Corporation

Dear Mr. MacBride:

On July 30, 2012, the North American Electric Reliability Corporation (NERC) submitted a filing that seeks approval of proposed amendments to NERC's Delegation Agreement with Reliability*First* Corporation (RFC), including approval of amendments to RFC's Bylaws and Reliability Standards Development Procedure.

Notice of this filing was issued on July 31, 2012, with protests and interventions due on or before August 20, 2012.

Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.214. No protests were filed.

NERC's uncontested filing is accepted pursuant to the relevant authority delegated to the Director, Office of Energy Market Regulation, under 18 C.F.R. § 375.307 as of the date of this order.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.307(a)(2)(vi). This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents. Such action shall not be deemed as recognition of any claimed right or obligation associated therewith

and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order pursuant to 18 C.F.R. § 385.713.

Sincerely,

Penny S. Murrell, Director
Division of Electric Power Regulation-Central

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)** **)**	**Docket No. RM11-11-000**

QUARTERLY REPORT OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION ON STATUS OF DEVEOPMENT OF VERSION 5 CRITICAL INFRASTRUCTURE PROTECTION RELIABILITY STANDARDS

On February 10, 2011, the North American Electric Reliability Corporation ("NERC") filed a petition seeking Federal Energy Regulatory Commission ("FERC" or the "Commission") approval of the "Version 4" Critical Infrastructure Protection ("CIP") Reliability Standards, CIP-002-4 through CIP-009-4. The Version 4 CIP Reliability Standards provide a cybersecurity framework for the identification and protection of "Critical Cyber Assets" that are associated with "Critical Assets" to support the reliable operation of the Bulk-Power System.

On April 19, 2012, the Commission issued an order approving the Version 4 CIP Reliability Standards[1] and imposing a March 31, 2013, deadline by which time NERC must file CIP Reliability Standards that are fully compliant with Order No. 706.[2] The Commission also required the submission of reports at the "beginning of each quarter" explaining whether NERC is "on track to meet the deadline and describe the status of its CIP standard development efforts."[3] The instant filing is submitted in compliance with this directive.[4]

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[1] *Version 4 Critical Infrastructure Protection Reliability Standards*, Order No. 761, 139 FERC ¶ 61,058 (2012).

[2] *Mandatory Reliability Standards for Critical Infrastructure Protection*, Order No. 706, 122 FERC ¶ 61,040, *denying reh'g and granting clarification*, Order No. 706-A, 123 FERC ¶ 61,174 (2008), *order on clarification*, Order No. 706-B, 126 FERC ¶ 61,229 (2009), *order denying clarification*, Order No. 706-C, 127 FERC ¶ 61,273 (2009).

[3] Order No. 761 at P 4.

I. Notices and Communication

Notices and communications with respect to this filing may be addressed to the following:[5]

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II. Attachments

Attachment A Successive Ballot Results

Attachment B Project 2008-06 – Cyber Security Order 706 – V5 Standard Drafting Team Meeting Agendas and Notes

Attachment C Project 2008-06 – Cyber Security Order 706 – V5 Project Schedule

III. Status of CIP Version 5 Standard Development Efforts

In the third quarter of 2012 (*i.e.*, July 1 to September 30, 2012), there was a posting for a parallel formal comment and successive ballot period, two drafting team meetings, and several conference calls as described in further detail below.

A parallel formal comment and 12 successive ballot windows for the "Version 5" CIP standards (CIP-002-5 Cyber Security –BES Cyber System Identification; CIP-003-5 Cyber

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[4] In response to the first quarterly report submitted on July 2, 2012, the Commission granted NERC's request to file such reports 30-days after the end of each calendar quarter. *See Notice of Extension of Time*, Docket No. RM11-11-000 (July 24, 2012).

[5] Persons to be included on FERC's service list are indicated with an asterisk. NERC requests waiver of 18 C.F.R. § 385.203(b) to permit the inclusion of more than two people on the service list.

Security – Security Management Controls; CIP-004-5 Cyber Security – Personnel and Training; CIP-005-5 Cyber Security – Electronic Security Perimeter(s); CIP-006-5 Cyber Security – Physical Security; CIP-007-5 Cyber Security – Systems Security Management; CIP-008-5 Cyber Security – Incident Reporting and Response Planning; CIP-009-5 Cyber Security – Recovery Plans for BES Cyber Assets and Systems; CIP-010-1 Cyber Security – Configuration Change Management; CIP-011-1 Cyber Security – Information Protection), one ballot for the associated implementation plan, and one ballot for a set of new and revised NERC Glossary definitions, began on September 11, 2012, and ended October 10, 2012. All 12 successive ballots achieved at least two-thirds approval. *See* **Attachment A**.

The Project 2008-06 – Cyber Security Order 706 – V5 standard drafting team met from July 10-12, 2012, and from August 14-16, 2012. Specific information regarding the issues discussed at this meeting is included herein at **Attachment B** and is posted on the NERC website.[6] In addition, conference calls were held by the drafting team on July 2, 2012, July 19, 2012, July 27, 2012, August 2, 2012, August 6, 2012, September 5, 2012, and September 6, 2012. The drafting team also conducted informational industry webinars on September 11, 2012, ("Industry Webinar (1 of 2) for Version 5 CIP Standards: A Focus on "Correcting Deficiencies"), and September 21, 2012, ("Industry Webinar (2 of 2) for Version 5 CIP Standards: Successive Ballot Update").[7] A drafting team teleconference was held on October 12, 2012, and a drafting team meeting is scheduled for October 23-25, 2012, in Sacramento, CA.

With respect to whether the Version 5 standard drafting team is on schedule to meet the March 31, 2013, deadline, a project schedule is maintained on the NERC website and is publicly

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6 http://www.nerc.com/filez/standards/Project_2008-06_Cyber_Security-RF.html.

7 http://www.nerc.com/page.php?cid=1|83.

available.[8] *See* **Attachment C**. The current schedule projects that NERC will meet the Commission's March 31, 2013, deadline.

IV. Conclusion

NERC respectfully requests that the Commission (i) accept this Compliance Filing in accordance with the Commission's directive in Order No. 761, and (ii) find that the proposal to submit future quarterly reports based on the Commission's electric quarterly report schedule is reasonable and satisfies the directive in Order No. 761.

Respectfully submitted,

/s/ Willie L. Phillips

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Dated: October 31, 2012

[8] *See* http://www.nerc.com/docs/standards/dt/Project_2008-06_Cyber_Security_Order_706__Gantt_Chart1_062712.pdf.

Attachment A

Successive Ballot Results

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2008-06 Cyber Security Order 706 (CIP Version 5)

Successive Ballot Results

Now Available

Twelve successive ballot windows for the following ten CIP standards, one ballot for the associated implementation plan, and one ballot for a set of new and revised NERC Glossary definitions, closed on Wednesday, October 10, 2012. The drafting team thanks stakeholders for the careful consideration of such a large volume of documents, and for the substantive and constructive feedback received.

Voting statistics for each ballot are listed below, and the Ballot Results webpage provides a link to the detailed results.

Ballot	Results
CIP-002-5 Cyber Security — BES Cyber System Identification	Quorum: 80.58% Approval: 74.85%
CIP-003-5 Cyber Security — Security Management Controls	Quorum: 80.37% Approval: 89.50%
CIP-004-5 Cyber Security — Personnel and Training	Quorum: 80.58% Approval: 85.58%
CIP-005-5 Cyber Security — Electronic Security Perimeter(s)	Quorum: 80.58% Approval: 89.46%
CIP-006-5 Cyber Security — Physical Security	Quorum: 80.58% Approval: 92.11%
CIP-007-5 Cyber Security — Systems Security Management	Quorum: 80.58% Approval: 87.73%
CIP-008-5 Cyber Security — Incident Reporting and Response Planning	Quorum: 80.58% Approval: 91.74%
CIP-009-5 Cyber Security — Recovery Plans for BES Cyber Assets and Systems	Quorum: 80.58% Approval: 91.73%
CIP-010-1 Cyber Security — Configuration Change Management	Quorum: 80.58% Approval: 84.60%
CIP-011-1 Cyber Security — Information Protection	Quorum: 80.58% Approval: 92.90%
CIP V5 Implementation Plan	Quorum: 78.93% Approval: 94.00%
CIP V5 Definitions	Quorum: 79.13% Approval: 91.59%

Next Steps

The drafting team will consider all comments submitted, and based on the comments will determine whether to make additional changes. If the drafting team determines that no substantive changes are required to address the comments, recirculation ballots will be conducted.

Background

In 2008, FERC Order No. 706 directed the ERO to develop modifications to Version 1 of the NERC CIP Cyber Security Standards to address a range of concerns in various areas of the Version 1 standards.

Version 5 of the NERC CIP Cyber Security Standards is intended to address all remaining standards related issues of FERC Order No. 706.

The SDT believes the NERC Version 5 CIP Cyber Security Standards provide a cyber security framework for the categorization and protection of BES Cyber Systems to support the reliable operation of the Bulk Electric System. These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the cyber systems needed to support Bulk Electric System reliability, and the risks to which they are exposed. Additional information about the project is available on the project page.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Attachment B

Project 2008-06 – Cyber Security Order 706 –
V5 Standard Drafting Team Meeting Agendas and Notes

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Meeting Agenda
Project 2008-06 Cyber Security Order 706 Standard Drafting Team

July 10-12, 2012 | 8:00 a.m. – 6:00 p.m. CT

Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369
(763) 445-5500

Dial-in: 1-866-740-1260 | Access Code: 7149593 | Security Code: 997870

Administrative

1. **Introductions**
2. **Determination of Quorum**

   The rule for NERC Standard Drafting Team (SDT) states that a quorum requires two-thirds of the voting members of the SDT to be present.
3. **NERC Antitrust Compliance Guidelines and Public Announcement**

   It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition. It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.
4. **Review Current Team Roster**

5. **Review Meeting Agenda and Objectives**
    a. Continue review/response to industry comments and modify standards in response.
    b. Finalize approach to previously identified significant unresolved issues.

Agenda

1. **Approval of Notes from Previous Meetings**
2. **Update on Successive Ballot Timeline**
3. **Finalize Approaches to Significant Issues**
    a. Program-based requirement approach (non-zero-defect).
    b. Addressing guidance in Order 761.
    c. CIP-002-5 BES Cyber System Identification.
    d. Immediate revocation of access.
    e. Physical Security Perimeter monitoring and alerting.
4. **Finalize Response to Comments (Review Additional Modifications to Each Standard)**
5. **Prepare Standards for Quality Review as Available**
6. **Action Items and Next Steps**
7. **Planning for Webinars, Full Team Calls, etc.**
8. **Future Meeting Schedules and Venues**
    a. August 14-16, 2012, Columbus, OH (AEP)
    b. September 11-13, 2012 (to be determined)
9. **Adjourn**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Meeting Notes

Project 2008-06 Cyber Security Order 706 Standard Drafting Team

July 10-12, 2012
Maple Grove, MN

Administrative

1. **Introductions and Chair's Remarks**

The acting chair brought the meeting to order at 8:00 a.m. CT on Tuesday, July 10, 2012 at Great River Energy (GRE) Headquarters facilities. Meeting participants were:

Members		
Rob Antonishen, Ontario Power	Rene Bourassa, Hydro Quebec (via teleconference)	Sharon Edwards, Duke Energy
Jerry Freese, AEP	Christine Hasha, ERCOT	Philip Huff, Vice Chair, AECC
Doug Johnson, ComEd	Richard Kinas, OUCI	Robert Lloyd, SCE
Scott Mix, NERC	Steven Noess, NERC Advisor	Kevin Sherlin, SMUD
David Revill, GA Transmission	Thomas Stevenson, Constellation	John Varnell, Tenaska Power Services
William Winters, APS		

Observers		
Tom Alrich, Honeywell	Joe Bucciero, EnerNex	Richard Burt, MRO
David Dockery, AECI	James Fletcher, AEP	Annette Johnston, MidAmerican
Michael Keene, FERC	Collin Martin, Oncor	Jeremy Morgan, Progress Energy
Sharon Koller, Alliant Energy	Dan McAuley, Southern Company	Brian Newell, AEP
Eduardo Santiago, Southern Compnay	Cade Simmons, MidAmerican	Josh Smith, Southern Company
Jennifer White, Alliant Energy		

2. **Determination of Quorum**

   The rule for NERC Standard Drafting Team (the team or SDT) states that a quorum requires two-thirds of the voting members of the SDT. Quorum was achieved as 15 of 16 total members were present.

3. **NERC Antitrust Compliance Guidelines and Public Announcement**

   The NERC Antitrust Compliance Guidelines and public announcement were delivered.

4. **Review Team Roster**

   The Standards Committee approved the removal of one member from the drafting team on May 24, 2012, as the member changed roles and is no longer able to participate actively in the drafting team's activities. An updated team roster has been posted to the team's project page.

5. **Review Meeting Agenda and Objectives**

   No changes were made to the meeting agenda or objectives. The meeting objectives were to continue review of industry comments, finalize approach to significant unresolved issues, and prepare changes to the standards in response.

Agenda Items

1. **Approval of Notes from Previous Meetings**

2. **Update on Ballot Results and Process Toward Successive Ballot**

   The team reviewed the plan to prepare another draft for successive ballot, to be posted in August or September 2012. The team re-acknowledged that it will need to complete a successive ballot and recirculation ballot before the end of 2012 in order to meet the deadline for filing Version 5 imposed by FERC Order No. 761. Furthermore, the team sought from the Standards Committee deferral of Violation Severity Levels (VSLs) for non-binding poll, and the Standards Committee approved deferral of posting VSLs for non-binding poll until the recirculation ballot. The SDT also reviewed progress in finalizing comment response summaries for each of the set of questions submitted during the formal comment period that ended in May 2012. Each member assigned to a question indicated that he or she was on track to finish the comment responses before the beginning of the August 2012 face-to-face SDT meeting.

3. **Major Issues and Actions**

   The focus of the meeting was to continue improving and modifying the standards in response to industry input from formal comments. The SDT made several changes at its June 2012 in direct response to comments, and this meeting focused on several remaining issues, many of which applied broadly across more than one standard. The team met in plenary session for the duration of the meeting, and it focused on those standards that had less focus during June's meeting.

Namely, CIP-003-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1. Among several issues identified or resolved during these meetings include, but are not limited to:

a. The SDT discussed with NERC's director of compliance operations the direction NERC is moving with respect to compliance monitoring. The discussion included presentation of the broader ERO directions to incorporate risk-informed approaches.

b. In addition to the compliance monitoring discussion, the SDT discussed incorporating a self-correcting component within several requirements. As part of its obligation under FERC Order No. 706, the SDT has an obligation to consider applicable features of the NIST Risk Management Framework. Thus, Version 5 has incorporated the "Assess" and "Monitor" processes of the NIST Risk Management Framework in the development of the requirements and enabled these processes through additional language for identifying, assessing, and correcting deficiencies in controls. The SDT has incorporated within CIP Version 5 a recognition that certain requirements should not focus on individual instances of failure as a sole basis for determining a violation of the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. Note that, where used, the addition of language modifies "implement"; it does not itself require or specify internal controls, though it certainly enables their use for those entities that have adopted an internal controls approach. Where used, the requirements incorporate the forward-looking language into the main requirement, which ties in with CIP Version 5's use of accompanying tables. It is presented in those requirements as follows: "Each Responsible Entity shall implement**, in a manner that identifies, assesses, and corrects deficiencies,** one or more documented processes (or program, etc., as specified by the requirement) that collectively include each of the applicable items in [the referenced table]."

c. The team continued to review generally Order No. 761 guidance and its implications on the drafting team's work.

d. As part of the movement to incorporate a self-correcting aspect into the requirements, the SDT also discussed the importance of synchronizing those concepts within other supporting documents, such as Reliability Standard Audit Worksheets (RSAWs) and the VSLs. The SDT will work with NERC to provide input into the RSAWs so that an example RSAW can be posted for comment alongside the next posting of the standards.

e. The SDT reviewed the decisions for global changes, which are included in the June 2012 meeting summary, and reviewed and confirmed those changes in the standards.

f. Synchronize all measures to reflect the approach that measures are non-exhaustive lists of examples. To accomplish this, the SDT added the "Examples of" concept to precede "evidence includes, but is not limited to, . . ."

g. In CIP-004-5, the SDT discussed some questions regarding the PRA process. Specifically, some commenters were concerned that a PRA would be required for a change in role, and the SDT clarified that its intent is for the entity's process to determine what is appropriate and that the standard should be clear that a PRA should not be any older than 7 years, not that it must be conducted for each new role. To provide clarity, the SDT does not distinguish between a first time or renewal PRA, and as written, a PRA that is no older than 7 years is a condition for access. As a condition of access, it must have been conducted either prior to granting such access or prior to renewing such access.

h. The SDT also clarified the identity verification requirement by specifying that the entity should have a process to verify identity, but the SDT does not prescribe how.

i. The SDT discussed but did not make a final determination on the MW threshold for Balancing Authorities (BAs). An observer in attendance provided the SDT with information and a summary of the 22 commenters that discussed this issue in the comments for draft 2. The SDT discussed the topic and seemed to agree that, in general, even if a BA goes down, there would still be voltage at the actual generators.

j. The SDT also finalized several other changes for clarity, style, and grammar.

4. **Action Items and Next Steps**

   a. Team members were reminded of responsibility for completing summaries for individual questions from the comment forms. Summaries must be completed before the end of July 2012.

   b. Participate in all topic-specific SDT interim calls.

5. **Future Meeting(s)**

   a. August 14-16, 2012 (AEP in Columbus, OH).

   b. September 11-13, 2012 (to be determined).

6. **Adjourn**

   The meeting was adjourned at 4:00 p.m. CT on July 12, 2012. The chair thanked GRE for use of its facilities and thanked the members for a productive session.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Meeting Agenda
Project 2008-06 Cyber Security Order 706 Standard Drafting Team

August 14-16, 2012 | 8:00 a.m. – 6:00 p.m. CT

AEP
1 Riverside Plaza
Columbus, OH 43215
(614) 716-2128

Dial-in: 1.866-740-1260 | Access code: 7149593 | Security Code: 648548

Administrative

1. **Introductions**
2. **Determination of Quorum**

   The rule for NERC Standard Drafting Team (SDT) states that a quorum requires two-thirds of the voting members of the SDT to be present.
3. **NERC Antitrust Compliance Guidelines and Public Announcement**

   It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition. It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.
4. **Review Current Team Roster**

5. **Review Meeting Agenda and Objectives**
   a. Finalize review/response to industry comments and modify standards in response.
   b. Finalize draft 3 of the standards for submission to NERC quality review (QR).

Agenda

1. **Approval of Notes from Previous Meetings**
2. **Update on Successive Ballot Timeline**
3. **Standards Approach in Certain Requirements: Correcting Deficiencies**
4. **Finalize Response to Comments – Review Additional Modifications to Each Standard)**
5. **Discuss Violation Severity Levels (VSLs) and Synchronize with Standards – VSLs will be Posted**
6. **Approve Standards for QR**
7. **Action Items and Next Steps**
8. **Planning for Webinars, Full Team Calls, etc**
   a. September 11, 2:00 – 4:00 p.m. ET.
   b. September 21, 1:00 – 3:00 p.m. ET.
9. **Future Meeting Schedules and Venues**
   a. September 5-6, 2012, via Teleconference (11:00 a.m. – 5:00 p.m. ET each day).
   b. October 23-25, 2012, to be determined.
10. **Adjourn**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Meeting Notes

Project 2008-06 Cyber Security Order 706 Standard Drafting Team

August 14-16, 2012
Columbus, OH

Administrative

1. **Introductions and Chair's Remarks**

The chair brought the meeting to order at 8:02 a.m. ET on Tuesday, August 14, 2012 at AEP Headquarters. Meeting participants were:

Members		
Rene Bourassa, Hydro Quebec	Jay Cribb, Southern Company	Sharon Edwards, Duke Energy
Christine Hasha, ERCOT (via conference call)	Philip Huff, Vice Chair, AECC	Jerry Freese, AEP
Doug Johnson, Exelon	John Lim, Chair, Consolidated Edison	Scott Mix, NERC
Steven Noess, NERC Advisor	Robert Preston Lloyd, Southern California Edison	David Revill, GA Transmission
Kevin Sherlin, SMUD (via conference call)	Thomas Stevenson, Constellation	John Varnell, Tenaska Power Services (via conference call)
William Winters, APS (via conference call)		

Observers		
Michael Bailey, FirstEnergy	Peter Buerling, FirstEnergy	Randy Calhoun, AEP
Bryan Carr, PacifiCorp	Trey Cross, ACES Power Marketing	David Dockery, AECI
James Fletcher, AEP	John Fridye, Ventyx	Doug Hohlbaugh, FirstEnergy
Annette Johnston, MidAmerican Energy Company	Michael Keane, FERC	Sharon Koller, Alliant Energy

Observers		
Collin Martin, ONCOR	Dan McAveley, Progress Energy	Don Miller, FirstEnergy
Nathan Mitchell, APPA	Jeremy Morgan, Progress Energy Carolinas	Brian Newell, AEP
James Rappach, AEP	Troy Rhoades, FirstEnergy	Carlo Santarelli, AEP
Tim Sheerer, FirstEnergy	Josh Smith, Southern Company Services	Ryan Stewart, NERC
Jennifer White, Alliant Energy	Spencer Young, PacifiCorp	

2. **Determination of Quorum**

   The rule for NERC Standard Drafting Team (the team or SDT) states that a quorum requires two-thirds of the voting members of the SDT. Quorum was achieved as 14 of 16 total members were present.

3. **NERC Antitrust Compliance Guidelines and Public Announcement**

   The NERC Antitrust Compliance Guidelines and public announcement were delivered.

Agenda Items

1. The SDT reviewed the upcoming timeline as there are a few time sensitive areas the SDT needs to address. The timeline discussed and agreed to is:

   - 30-day comment period from approximately September 12 – October 12, 2012.
   - 10-day ballot period during the last ten days of the 30-day comment period.
   - SDT conference calls September 5-6, 2012 to discuss and finalize quality review (QR) consideration.
   - SDT face to face meeting to address comments prior to recirculation ballot.
   - Recirculation ballot shortly after the face to face meeting.
   - Board of Trustee (BOT) approval at its November 2012 meeting if recirculation complete or in December 2012.
   - Filing with FERC shortly after BOT approval to meet deadline in Order No. 761.

2. **Major Issues and Actions**

   The focus of the meeting was to discuss the proposed self-correcting language for the applicable Requirements, discuss CIP-002-5 through CIP-011-1 regarding changes from the second draft to the current state of the standards for concensus and approval for submission to QR, and discuss the CIP Version 5 Definitions document.

In summary, Tuesday focused on the zero defect approach to the applicable Requirements within the CIP standards, the review of CIP-002-5, CIP-003-5 and CIP-005-5. Wednesday focused on the draft CIP-006-5 Reliability Standard Audit Worksheet (RSAW) and the continued review of CIP-005-5 and CIP-007-5. Thursday focused mainly on the development of the Implementation Plan as well as the review of CIP-004-5 and CIP-006-5. Among several issues identified during these meetings for continued team discussion include, but are not limited to:

a. Standards approach moving from *whether* deficiencies occur to *correcting* deficiencies. The SDT took a straw poll to determine if the SDT is comfortable with including language at all on this issue. The proposal is whether the SDT is in support of including language in the applicable Requirements to support the concept of identify, assess and correct. The straw poll reflected team concensus. The SDT is in support of using the language.

b. Stemming from the discussion above, the team reviewed different proposals from industry stakeholders regarding the self-correcting language. Many of the proposals included detail language indicating what *is not* a violation, and other proposals modified "process" instead of "implement." The team agreed with the concept of many of the proposals, but they agreed that many of the concepts in the proposed alternative language would be more appropriate in other compliance monitoring documents, such as an RSAW. The SDT is moving forward with the current proposal of the language (#1). The SDT will provide outreach to stakeholder groups on this language to solicit feedback and comments to guage the industry's reaction.

c. The SDT discussed slides on the CIP Version 5 approach for correcting deficiencies. The approach shifts focus from *whether* defiencies occur to *correcting defiencies*. As mentioned above, a number of prosposals to incorporate the identify, assess, and correct deficiencies language were provided prior to the meeting, and the team returned to the language of "implement, in a manner that identifies, assesses, and corrects deficiencies…" It is important to note that the language does not *require* an entity to have internal controls but provides flexibility to an entity if it is using an internal controls or compliance management approach.

d. The SDT discussed whether the self-correcting language should be in all Requirements or only certain Requirements. The SDT determined that it is only appropriate in certain requirements, such as highly recurrent or documentation-type requirements, and that other requirements are more binary in nature with respect to meeting the required performance. Furthermore, using it selectively further supports a risk-informed approach that recognizes that some requirements should be performed without flaw. As such, the approach will only be included for approximately half of the Requirements.

e. The SDT reviewed the draft RSAW for CIP-006-5, which was modeled after the COM-003-1 RSAW. The SDT expects that the other nine RSAWs will be developed with continued industry

and SDT input following approval of the CIP Version 5 standards. NERC plans to post this draft RSAW as an informational document concurrent with draft 3's posting for successive ballot.

f. The SDT reviewed the implementation plan. There was discussion regarding the effective dates and how Version 4 of the CIP standards will impact Version 5. NERC is working on a smooth transition for each Version. In the implementation plan for the CIP Version 5 standards, the SDT had previously proposed to extend Version 3 until the effective date of Version 5. In doing so, the effective date proposes that Version 4 will be superseded by Version 5 and not go into effect. Even though Version 4 has been approved by order, the SDT always contemplated such approval during the development of the implementation plan language. That order does not change the SDT's proposal. The expectation of the order is why the SDT included language implementation plan's effective date to specify that the extension of Version 3 until Version 5, and that Version 4 would not go into effect, would occur "notwithstanding any order to the contrary." There is no change in the SDT's intent and proposal to extend Version 3 until Version 5, and for Version 5 to supersede Version 4, notwithstanding the recent order approving Version 4. The SDT also understands, as is the case for any standards proposal by the industry, that the proposal is subject to approval by appropriate regulatory authorities.

g. Within the individual standards for CIP Version 5, the effective dates have been modified so that they are specific to the particular standard. In doing so, the reference to extending Version 3 and superseding Version 4 has been removed, as the Implementation Plan is the appropriate place for that language (where it remains, as described above). Thus, while there is no change to the SDT's proposal, you will notice that the individual, standard-by-standard effective dates have been modified to the correct style and form.

h. There was a general discussion with regards to what the questions will be during the next posting. Since this is the third posting, the SDT has reviewed thousands of pages of perspectives, and it is not looking for the volume of comments previously submitted. It believes that the set of standards being prepared for posting reflect careful consideration of the varied formal and informal inputs into the process that reflect a consensus position. As such the SDT agreed that to keep the number and amount of questions to a minimum.

3. **Action Items and Next Steps**

a. NERC has already announced the September 11, 2012 webinar, and it will send an announcement for September 21, 2012 webinar, along with reminders for both of the webinars as the date approaches.

b. A subteam of the SDT and Observer collaborators is working on VSLs and will provide them to the SDT within two weeks of the meeting.

c. The SDT Chair will finalize the consideration of directives and will provide that to the SDT for submittal to QR.

d. An SDT member will provide language in the background section for the protected cyber asset concepts.

e. Several other members had small areas for clarity they will provide for inclusion in the background and guidelines sections of the standards.

4. **Planning for Webinars, Full Team Calls, etc.**

   a. September 11, 2:00 – 4:00 p.m. ET.

   b. September 21, 1:00 – 3:00 p.m. ET.

5. **Future Meeting Schedules and Venues**

   a. September 5-6, 2012, via Teleconference (11:00 a.m. – 5:00 p.m. ET each day).

   b. October 23-25, 2012, Sacramento, CA (SMUD Hosting).

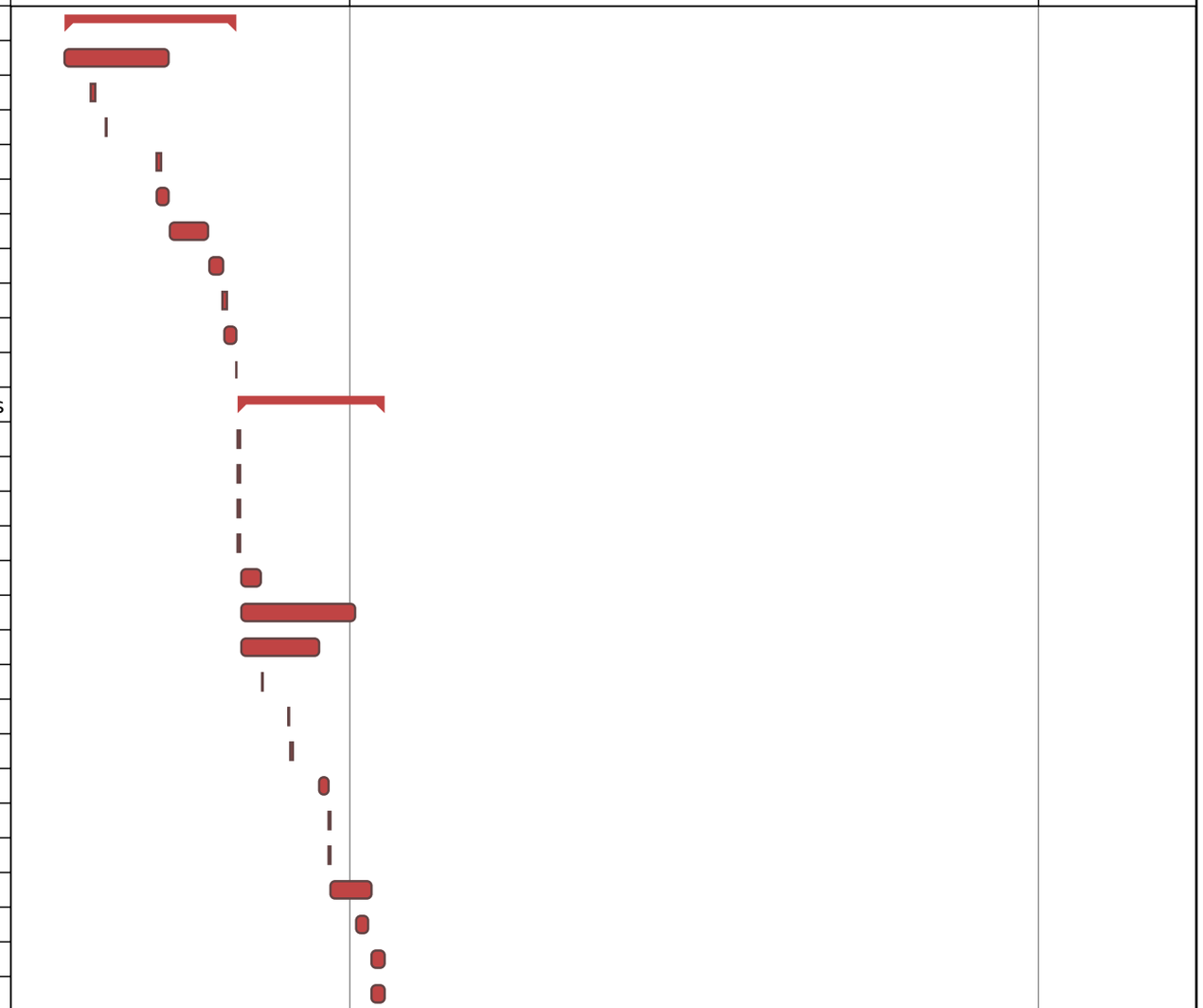
6. **Adjourn**

   The meeting was adjourned at 4:01 p.m. ET on August 16, 2012.

Attachment C

Project 2008-06 – Cyber Security Order 706 – V5 Project Schedule

#	Name	Duration
1	**B - DRAFT STANDARD**	528 hrs
2	Write Draft Standard	40 days
3	SDT Meets (Atlanta, GA) to Solicit Industry Feedback	3 days
4	Sponsor Industry Webinar on Version 5 CIP Standards	1 days
5	SDT Meets (Westminster CA) to Finalize Documentation for QR	3 days
6	Send Posting Package to SPM for Quality Review	5 days
7	Perform Quality Review of Posting Package	15 days
8	Edit Posting Package based on QR and Send to SPM	6 days
9	SDT meets (Baltimore MD) to finalize CIP v5 Documentaiton for	3 days
10	Final Pre-Posting Review of Posting Package	5 days
11	Drafting Complete	0 days
12	**E - INITIAL BALLOT**	451.23 hrs
13	Write Draft Standard Posting and Ballot Pool Announcement	2 days
14	Post Draft Standard and Update Web Page	2 days
15	Post Draft Standard Posting and Ballot Pool Announcement	2 days
16	Distribute Draft Standard Posting and Ballot Pool Announcement	2 days
17	SDT Prepares for industry Webinar on CIP v5 Stadnards	7 days
18	Comment Period	60.44
19	Refresh Ballot Pool over 30 days	41.32
20	Webinar to the Industry (CIP-002, Defintions, and	1 days
21	Webinar to the Industry (CIP-003 thru -011)	1 days
22	SDT meets (via Conference Call) to review Webnar Questions	2 days
23	Write Initial Ballot Announcement	24 hrs
24	Post Initial Ballot Announcement	1 days
25	Distribute Initial Ballot Announcement	1 days
26	Conduct Initial Ballot over 10 days	21.81
27	Assemble Comments on Draft Standard and Send to Project	5 days
28	Assemble Ballot Comments on Draft Standard and Send to	5 days
29	Assemble Ballot Results and Update Web Page	5 days



Project: Project 2008-06 Cyber Security Order 706
Planned Start: 8/2/11
Projected Start: 8/2/11
Planned Completion: 2/25/13
Projected Completion: 3/29/13
Printed On: 10/22/12

The second phase (Phase 2) of Project 2008-06 Cyber Security Order 706 will require the SDT to propose modifications not included in Phase 1 of the project to bring the following standards into conformance with the ERO Rules of Procedure and to address the directives from FERC Order 706:
CIP-002-2 Critical Cyber Asset Identification

Planned
Summary
In Progress
Milestone

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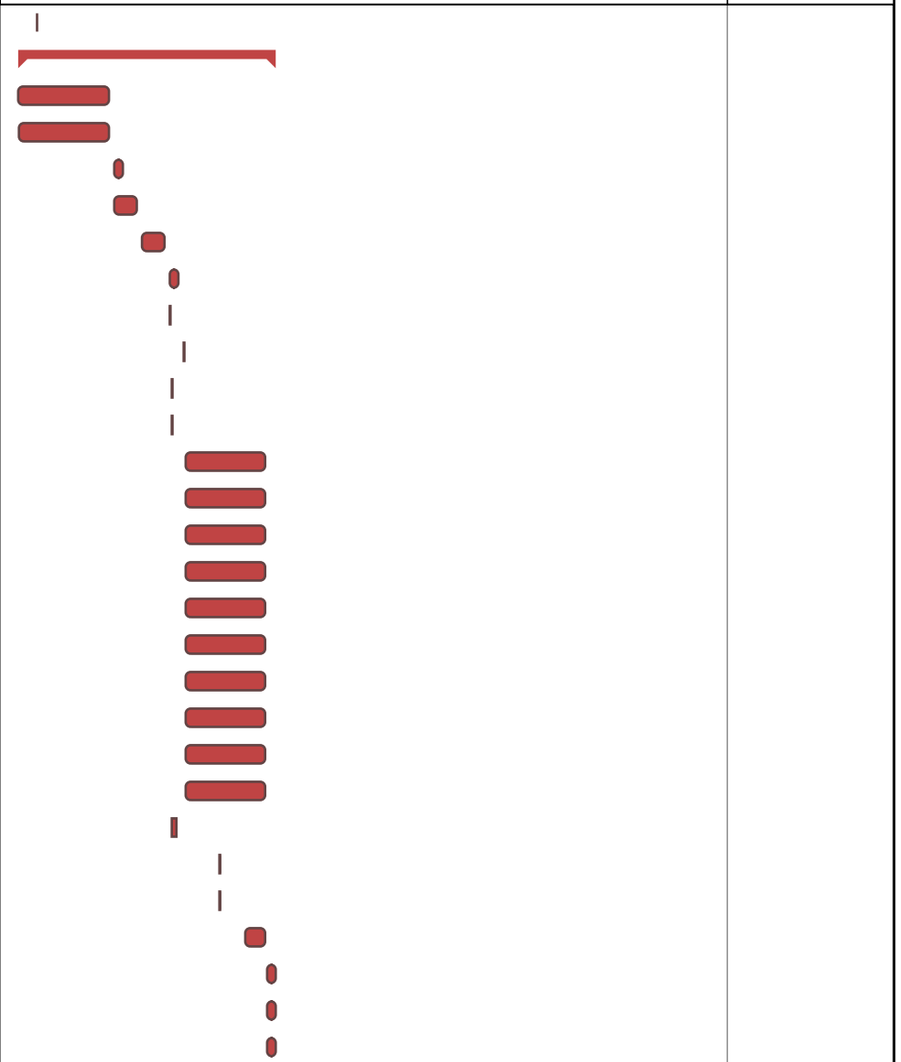
#	Name	Duration
30	Initial Ballot Complete	0 days
31	**F - SUCCESSIVE BALLOT**	752 hrs
32	Respond to Comments Received	34 days
33	Write Draft Standard	34 days
34	Send Posting Package to SPM for Quality Review	5 days
35	Perform Quality Review of Posting Package	10 days
36	Edit Posting Package based on QR and Send to SPM	10 days
37	Final Pre-Posting Review of Posting Package	5 days
38	Write Draft Standard Posting Announcement	1 days
39	Post Draft Standard and Update Web Page	1 days
40	Post Draft Standard Posting Announcement	1 days
41	Distribute Draft Standard Posting Announcement	1 days
42	CIP-002 Comment Period REF_POST_FBS	40 edays
43	CIP-003 Comment Period REF_POST_FBS	40 edays
44	CIP-004 Comment Period REF_POST_FBS	40 edays
45	CIP-005 Comment Period REF_POST_FBS	40 edays
46	CIP-006 Comment Period REF_POST_FBS	40 edays
47	CIP-007 Comment Period REF_POST_FBS	40 edays
48	CIP-008 Comment Period REF_POST_FBS	40 edays
49	CIP-009 Comment Period REF_POST_FBS	40 edays
50	CIP-010 Comment Period REF_POST_FBS	40 edays
51	CIP-011 Comment Period REF_POST_FBS	40 edays
52	Write Successive Ballot Announcement	3 days
53	Post Successive Ballot Announcement	1 days
54	Distribute Successive Ballot Announcement	1 days
55	Conduct Successive Ballot over 10 days	10 edays
56	Assemble Comments on Draft Standard and Send to Project	5 days
57	Assemble Ballot Comments on Draft Standard and Send to	5 days
58	Assemble Ballot Results and Update Web Page	5 days



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Milestone

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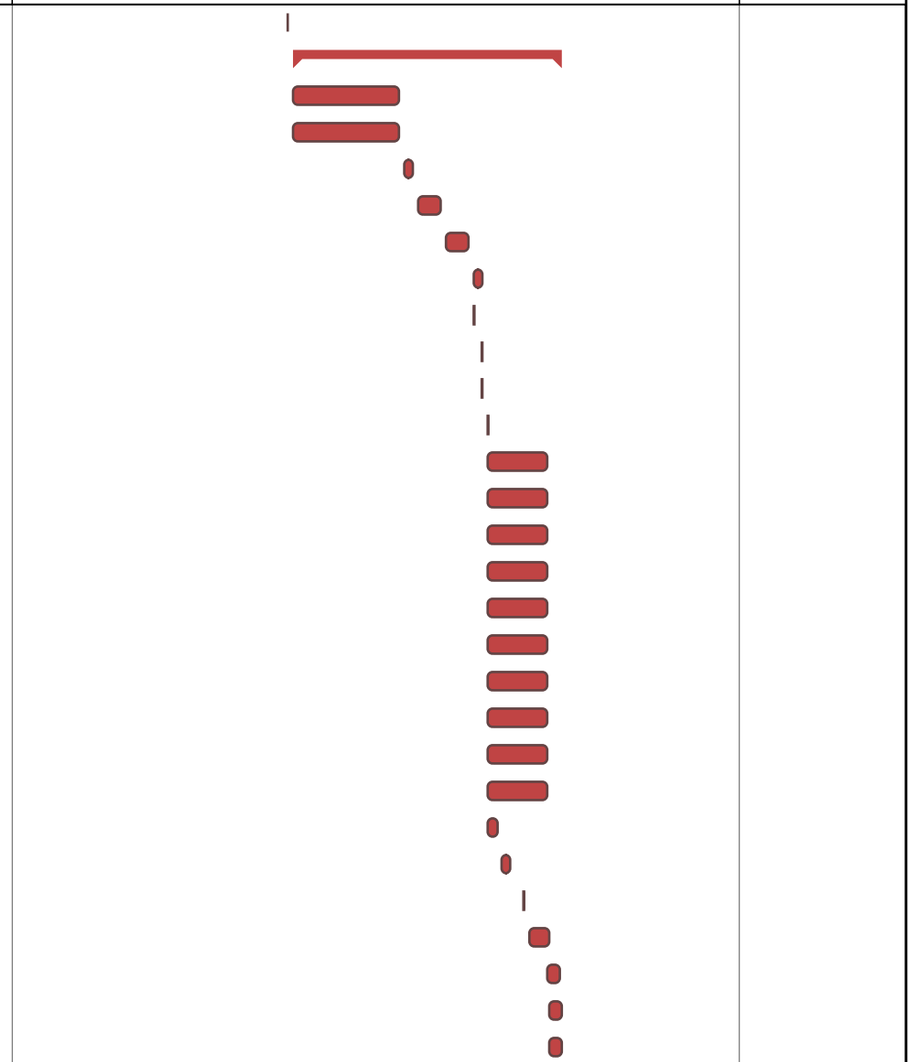
#	Name	Duration
59	Successive Ballot Complete	0 days
60	**F2 - 2nd SUCCESSIVE BALLOT**	784 hrs
61	Respond to Comments Received	40 days
62	Write Draft Standard	40 days
63	Send Posting Package to SPM for Quality Review	5 days
64	Perform Quality Review of Posting Package	10 days
65	Edit Posting Package based on QR and Send to SPM	10 days
66	Final Pre-Posting Review of Posting Package	5 days
67	Write Draft Standard Posting Announcement	1 days
68	Post Draft Standard and Update Web Page	1 days
69	Post Draft Standard Posting Announcement	1 days
70	Distribute Draft Standard Posting Announcement	1 days
71	CIP-002 Comment Period REF_POST_FBS	30 edays
72	CIP-003 Comment Period REF_POST_FBS	30 edays
73	CIP-004 Comment Period REF_POST_FBS	30 edays
74	CIP-005 Comment Period REF_POST_FBS	30 edays
75	CIP-006 Comment Period REF_POST_FBS	30 edays
76	CIP-007 Comment Period REF_POST_FBS	30 edays
77	CIP-008 Comment Period REF_POST_FBS	30 edays
78	CIP-009 Comment Period REF_POST_FBS	30 edays
79	CIP-010 Comment Period REF_POST_FBS	30 edays
80	CIP-011 Comment Period REF_POST_FBS	30 edays
81	Write Successive Ballot Announcement	5 edays
82	Post Successive Ballot Announcement	5 days
83	Distribute Successive Ballot Announcement	1 days
84	Conduct Successive Ballot over 10 days	10 edays
85	Assemble Comments on Draft Standard and Send to Project	5 days
86	Assemble Ballot Comments on Draft Standard and Send to	5 days
87	Assemble Ballot Results and Update Web Page	5 days



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Planned
In Progress
Summary
Milestone

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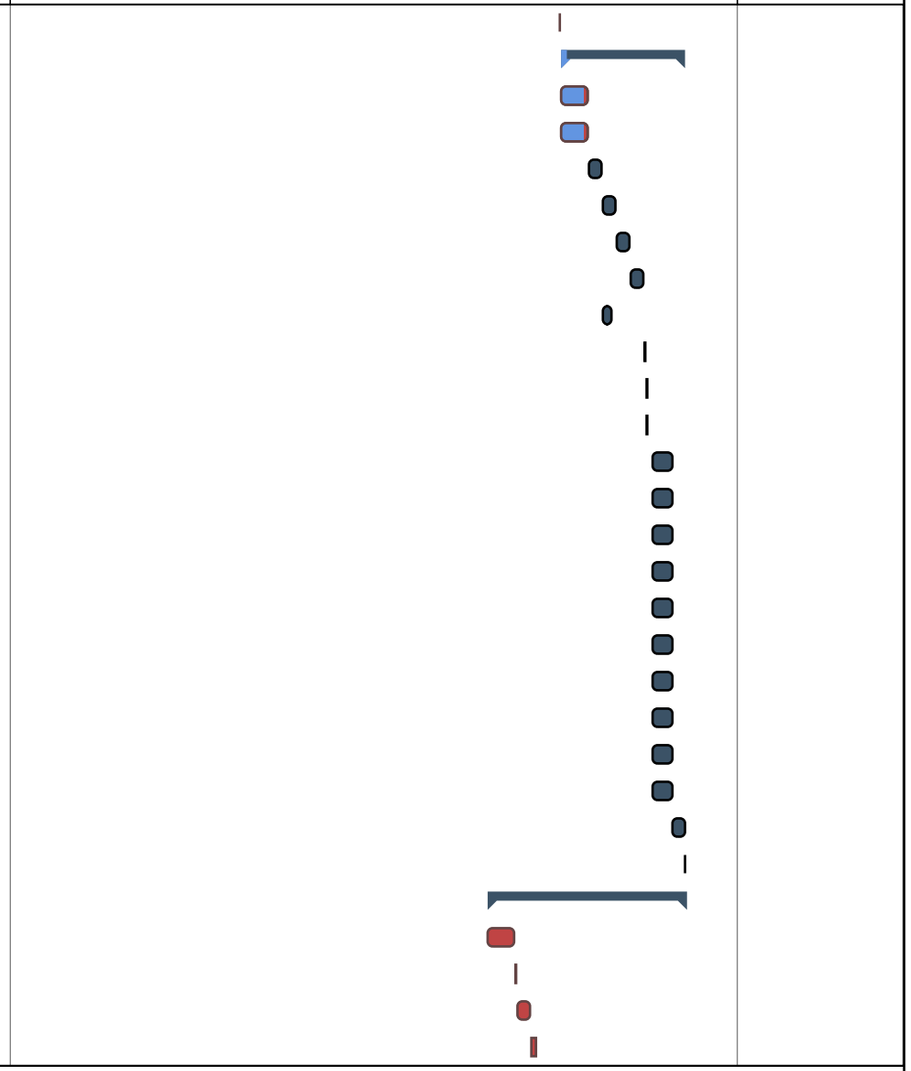
#	Name		Duration
88	Successive Ballot Complete	✓	0 days
89	**G - RECIRC BALLOT**		360 hrs
90	Respond to Comments Received	⚠	10 days
91	Write Draft of Standard	⚠	10 days
92	Send Posting Package to SPM for Quality Review		5 days
93	Perform Quality Review of Posting Package		5 days
94	Edit Posting Package based on QR and Send to SPM		5 days
95	Final Pre-Posting Review of Posting Package		5 days
96	Write Recirculation Ballot Announcement		3 days
97	Post Draft Standard and Update Web Page		1 days
98	Post Recirculation Ballot Announcement		1 days
99	Distribute Recirculation Ballot Announcement		1 days
100	CIP-002 Recirculation Ballot REF_BALLOT_R		10 edays
101	CIP-003 Recirculation Ballot REF_BALLOT_R		10 edays
102	CIP-004 Recirculation Ballot REF_BALLOT_R		10 edays
103	CIP-005 Recirculation Ballot REF_BALLOT_R		10 edays
104	CIP-006 Recirculation Ballot REF_BALLOT_R		10 edays
105	CIP-007 Recirculation Ballot REF_BALLOT_R		10 edays
106	CIP-008 Recirculation Ballot REF_BALLOT_R		10 edays
107	CIP-009 Recirculation Ballot REF_BALLOT_R		10 edays
108	CIP-010 Recirculation Ballot REF_BALLOT_R		10 edays
109	CIP-011 Recirculation Ballot REF_BALLOT_R		10 edays
110	Assemble Ballot Results and Update Web Page		5 days
111	Recirc Complete		0 days
112	**H - BOT APPROVAL**		584 hrs
113	Develop Board Materials	⚠	10 days
114	Send Board Materials to Standards Leadership	⚠	1 days
115	Perform Standards Leadership Review	⚠	5 days
116	Edit Board Materials based on Leadership Review	⚠	3 days



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Planned In Progress
Summary Milestone

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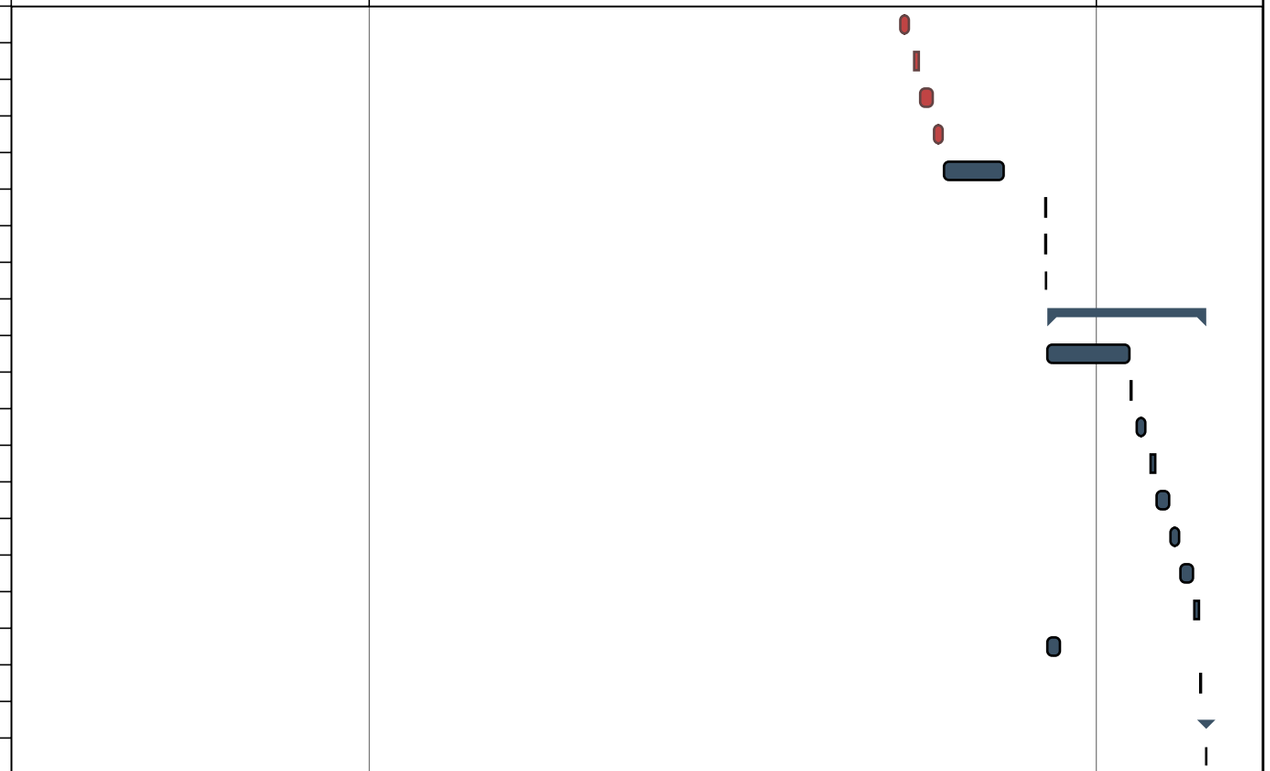
#	Name		Duration
117	Perform Legal Review	⚠	5 days
118	Edit Board Materials based on Legal Review and send to Exec	⚠	3 days
119	Perform Exec Mgmt Review	⚠	5 days
120	Edit Board Materials based on Exec Mgmt Review	⚠	3 days
121	Submit Board Materials to Board		30 edays
122	Present Board Materials to Board		1 days
123	Board Vote on Materials		1 days
124	BOT Approval Complete		0 days
125	**I - FILING**		448 hrs
126	Develop Draft Filing		30 days
127	Send Draft Filing to Standard Regulatory Initiatives		1 days
128	Perform Standards Regulatory Initiatives Review		5 days
129	Edit Draft Filing based on SRI Review and send to Legal		3 days
130	Perform Legal Review		5 days
131	Edit Draft Filing based on Legal Review and send to Exec Mgmt		3 days
132	Perform Exec Mgmt Review		5 days
133	Edit Draft Filing based on Exec Mgmt Review		3 days
134	Assemble development record		5 days
135	Assemble Final Filing Package		1 days
136	**Submit Final Filing Package**		0 hrs
137	Filing Complete		0 days



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CIP-002-2 Critical Cyber Asset Identification

Planned
Summary
In Progress
Milestone

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20121109-4001 FERC PDF (Unofficial) 11/09/2012

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RM11-20-002

November 9, 2012

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005-3801

Attention: Holly A. Hawkins, Attorney

Reference: Filing for Approval of Compliance Filing In Response to Order No. 763 on Automatic Underfrequency Load Shedding Reliability Standards

Dear Ms. Hawkins:

On May 7, 2012, the Commission issued Order No. 763 approving two Reliability Standards, PRC-006-1 and EOP-003-2, that address underfrequency load shedding plans.[1] Order No. 763 directed modifications to Reliability Standard PRC-006-1, Requirement R9, and to a Violation Risk Factor and Violation Severity Level associated with PRC-006-1. Order No. 763 directed NERC to make a compliance filing.

On August 9, 2012, NERC submitted a compliance filing modifying the Violation Risk Factor and Violation Severity Level in compliance with Order No. 763. Additionally, NERC proposes in the compliance filing to modify PRC-006-1, Requirement R9 in accordance with Order No. 763, when a standard development project is next initiated for modifying PRC-006-1.

Notice of this filing was issued on August 27, 2012, with comments, protests or motions to intervene due on or before September 10, 2012.

Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and

[1] *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, Order No. 763, 139 FERC ¶ 61,098 (2012).

20121109-4001 FERC PDF (Unofficial) 11/09/2012

Procedure. 18 C.F.R. § 385.214. No protests were filed specific to NERC's compliance with Order No. 763.[2]

NERC's uncontested filing is accepted pursuant to the authority delegated to the Director, Office of Electric Reliability, under 18 C.F.R. § 375.303.

This action shall not be construed as accepting any other contingency plan pursuant to 18 C.F.R. § 375.303(a)(1)(i) or any other data or report pursuant to C.F.R. § 375.303(b)(3)(iv). This action shall not be construed as approving any other application including Electric Reliability Organization or Regional Entity Rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such acceptance or approval shall not be deemed as recognition of any claimed right or obligation associated therewith; and such acceptance or approval is without prejudice to any findings or orders which have been or which may hereafter be made by the Commission in any proceeding now or pending or hereafter instituted by or against NERC.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

[2] On September 7, 2012, Dominion Resource Services, Inc. filed a motion to intervene and comments. The comments did not contest NERC's compliance with Order No. 763 and instead requested changes to proposed regional Reliability Standard PRC-006-SERC-01, which is the subject of pending Docket No. RM12-9-000.

Document Content(s)

RM11-20-0021.DOCX.....1-2

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Regional Reliability Standard PRC-006-NPCC-1	**)**	**Docket No. RM12-12-000**
Automatic Underfrequency Load Shedding	**)**	

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

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stacey.tyrewala@nerc.net

November 26, 2012

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Regional Reliability Standard PRC-006-NPCC-1	**)**	**Docket No. RM12-12-000**
Automatic Underfrequency Load Shedding	**)**	

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

The North American Electric Reliability Corporation ("NERC")[1] hereby provides these comments in response to the Federal Energy Regulatory Commission's ("FERC" or the "Commission") September 20, 2012, Notice of Proposed Rulemaking ("NOPR")[2] regarding the proposed regional Reliability Standard PRC-006-NPCC-1 (Automatic Underfrequency Load Shedding). The proposed regional Reliability Standard applies to generator owners, planning coordinators, distribution providers, and transmission owners in the Northeast Power Coordinating Council Region and is designed to ensure the development of an effective automatic underfrequency load shedding ("UFLS") program to preserve the security and integrity of the Bulk-Power System during declining system frequency events, in coordination with the NERC continent-wide UFLS Reliability Standard PRC-006-1.

I. BACKGROUND

In the NOPR, the Commission proposes to approve the proposed regional Reliability Standard PRC-006-NPCC-1, the associated violation risk factors ("VRFs") and violation severity levels ("VSLs"), implementation plan, and effective dates proposed by NERC. Proposed

---

[1] The Federal Energy Regulatory Commission certified NERC as the electric reliability organization ("ERO") in its order issued on July 20, 2006 in Docket No. RR06-1-000. *North American Electric Reliability Corporation*, 116 FERC ¶ 61,062 (2006).

[2] *Regional Reliability Standard PRC-006-NPCC-1—Automatic Underfrequency Load Shedding*, 140 FERC ¶ 61,203 (September 20, 2012) ("NOPR").

regional Reliability Standard PRC-006-NPCC-1 has 23 requirements, each having an associated measure of compliance. The proposed regional Reliability Standard is designed to work in conjunction with and augment Reliability Standard PRC-006-1 by mitigating the consequences of an underfrequency event, while accommodating differences in system transmission and distribution topology among Northeast Power Coordinating Council, Inc. ("NPCC") planning coordinators due to historical design criteria, makeup of load demands, and generation resources.

II. COMMENTS

The Commission seeks comment on: (1) the technical basis for the 57.8 Hz maximum tripping limit for existing nuclear units established in Requirement R19; and (2) the time-frames for actions that result in changes to the NPC UFLS program.

A. NERC Supports the Comments of the Northeast Power Coordinating Council

NERC supports the comments submitted by NPCC in this proceeding on the two issues addressed in the NOPR. NERC and NPCC assert that a region-wide and fully coordinated single set of UFLS requirements is of benefit to achieving an effective and efficient UFLS program. The requirements in the PRC-006-NPCC-1 standard are consistent with the PRC-006-1 NERC standard and support reliability.

NERC respectfully requests that the Commission approve PRC-006-NPCC-1 and the associated violation risk factors, violation severity levels and effective dates.

III. CONCLUSION

For the reasons stated above, NERC respectfully requests that the Commission accept these comments for consideration.

Respectfully submitted,

/s/ Stacey Tyrewala

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holly.hawkins@nerc.net
stacey.tyrewala@nerc.net

Dated: November 26, 2012

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 26th day of November, 2012.

/s/ Stacey Tyrewala
Stacey Tyrewala
Attorney for North American Electric Reliability Corporation

From: Guy V. Zito
To: rsc
Subject: NERC Approval of the CEAP
Date: Wednesday, October 10, 2012 12:58:22 PM

RSC et al,

Today the NERC Standards Committee unanimously approved the NERC Cost Effectiveness Analysis Process CEAP. An associated implementation plan was also approved which I will be discussing at the next RSC meeting.

Thanks,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

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(Example only) 11

Appendix B 12

Sample CIA and CEA Questions 12

Sample CIA Questions (Additional questions may be included as appropriate): 12

Sample CEA Technical Survey Questions (Additional questions may be included as appropriate): 12

Sample CEA Cost and Implementation Questions (SDT may include additional questions as appropriate): 13

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CEAP Report Document Format 15

CEAP Phase 1 Cost Impact Analysis (CIA) Report 16

CEAP Phase 2 Cost Effectiveness Analysis (CEA) Report 17

1. Introduction

Cost considerations are inherent in the development of Reliability Standards. One of the objectives of the NERC Cost Effective Analysis Process ("CEAP" or "Process") is to make such considerations transparent and to ensure that where decisions on Reliability Standards are made regarding cost effectiveness, these decisions are made in an open manner and are part of the standard development record.

While the reliability benefit of any one particular Reliability Standard may be small, taken together, the full battery of standards form a coherent and interdependent whole that helps ensure the reliability of the North American Bulk Power System ("BPS").Understanding the implementation costs and continuing costs of meeting compliance obligations for standards is vital to the development of these standards. Additionally, it is beneficial to industry stakeholders to identify and utilize the most cost effective methods of achieving the standards reliability objective and to afford the same industry stakeholders the ability to propose alternative methods of achieving the reliability objectives.

Regulatory authorities, federal, state and provincial, as well as the NERC Board of Trustees, Regional Entities and electric industry stakeholders have all expressed interest in a process to determine effectiveness and implementation costs of proposed or revised standards to improve reliability of facilities, resources and activities subject to NERC standards. The CEAP will also contribute to the record of standard development and become an integral part of filings with regulatory authorities providing additional needed information and justifications for the standards. Inclusion of implementation costs will also provide a sound basis to assist regulators in satisfying requirements for data that must accompany, and appear in, rulemakings (e.g. the Regulatory Flexiblity Act and Office Management and Budget requirments).

The foundation for this document was the Northeast Power Coordinating Council (NPCC) CEAP which was developed to address the NPCC Board of Director's concerns about implementation costs. The NPCC CEAP was effectively piloted and proved beneficial and has served to provide the concepts found in this NERC CEAP Guideline.

2. Purpose

The CEAP and associated implementation plan represent an initial effort towards addressing concerns regarding cost impacts (*e.g.,* implementation, maintenance, and ongoing compliance resource

requirements) associated with achieving reliability objectives for facilities, resources and activities subject to NERC standards.

The purpose of the CEAP is to establish guidelines for the solicitation of input and high level data from the industry, as part of and during the standards development process, to identify more cost effective ways to achieve the same or better reliability outcomes at equal or lower costs. The CEAP is intended to allow the industry the opportunity during the drafting process to identify alternative requirements or methods for meeting a standard's reliability objective that may be (i) less costly or (ii) equally or more effective, or (iii) more efficient. The CEAP, conducted in parallel with the drafting process, should not significantly delay the development of the standard and will add supporting information and background for the NERC stakeholders, the NERC Board of Trustees, and Federal, Provincial and State Regulatory Agencies to be utilized for decision-making.

The CEAP is not intended to provide a comprehensive cost impact or benefit analysis. The CEAP is a guideline to be used for informational gathering purposes only and is intended to collect beneficial data, not previously available during standards development. The CEAP is intended to augment and contribute to the efficiency and effectiveness of reliability standards and not delay or obstruct their development.

3. Process Overview

The CEAP will be conducted in two phases. Phase 1, Cost Impact Analysis ("CIA"), and Phase 2, Cost Effectiveness Analysis ("CEA"). Each phase of the CEAP will consist of a set of surveys with questions to be responded to by the industry.

The CEAP Final Report will consist of the (1) CEAP Phase 1 CIA Report and, (2) all combined CEAP Phase 2 CEA Reports.

The CEAP process will result in the production and publication of a CEAP Report, to be archived on the NERC website with the documentation related to the development of the standard.

3.1 Phase 1 Cost Impact Analysis (CIA)

Phase 1 will typically be conducted in conjunction with the Standards Authorization Request ("SAR") stage of a standard's development. The CIA is intended to collect estimated industry wide cost impacts (implementation, maintenance, and ongoing compliance resource requirements) and will evaluate potential reliability benefits of a proposed draft reliability standard. The CIA proposes an analysis of potential areas for coordination and efficiency gains in the development of proposed standards. The CIA will provide a high level "snapshot" of estimated cost impacts and mitigated reliability risks of the proposed reliability standard by soliciting input from stakeholders.

Questions posed during the Phase 1 CIA will focus on potential cost impacts and reliability risks to determine if the standard, in the view of stakeholders, would achieve or possibly exceed an Adequate Level of Reliability ("ALR"). Cost information collected in this phase should be "order of magnitude costs" to determine if a proposed standard will have excessive costs associated with it.

3.2 Phase 2 Cost Effectiveness Analysis (CEA)

The purpose of the CEA is to provide information about cost impacts (*e.g.*, implementation, maintenance, and ongoing compliance resource requirements) of draft reliability standards and their relative effectiveness, which will allow the industry to evaluate and propose alternative approaches for achieving the reliability objectives of the standard. Phase 2 will typically be conducted at the time of the first combined Formal Comment period and Ballot.

The CEA will involve two sets of survey questions which will be asked concurrently. The first set relates to technical feasibility and effectiveness of the proposed requirements as well as soliciting possible more cost effective alternatives to achieve the reliability objectives. The second set of questions will solicit cost impacts (*e.g.*, implementation, maintenance, and ongoing compliance resource requirements) and any related implementation information.

3.3 Cost Effective Analysis Process (CEAP) Report

All information provided during the CIA and CEA phases of the CEAP will be consolidated and evaluated to produce a CEAP report. The CEAP report will be provided to the NERC Standards Committee ("SC") and to the Standard Drafting Team ("SDT") for informational purposes.

All available resources will be utilized effectively and efficiently to produce a CEAP report in a timely manner that does not create unnecessary delays to the standards development process. It must be emphasized that the purpose of the CEAP is not to provide impediments to the NERC standard development process, but rather to inform stakeholders and decision makers of proposed industry cost impact and provide an opportunity for suggestions of alternate methods to achieve equally effective reliability goals and objectives that may result in less costly implementation. The final report is not intended to be analytical in nature but to promote better judgment and decision-making.

4. Confidentiality

All of the cost impact information submitted by entities will be reviewed and compiled prior to being made public, or presented to the SC and the SDT. The collection, review and compilation of information will be performed in conformance to all applicable requirements of Section 1500 of the NERC Rules of Procedure. Market sensitive issues of individual stakeholders may exist or be provided through the

responses to the CEAP questions. All necessary confidentiality will be maintained, and no market sensitive information or Critical Energy Infrastructure Information ("CEII") will be included in the final public report. Responders should identify confidential CEII or market sensitive information in their responses.

5. Process Details

5.1 NERC CEAP Process (See Figure 1: CEAP Process Flowchart)

1) When a draft SAR is posted for a thirty (30) day comment period, a set of CIA questions (Phase 1 of the CEAP) based on the sample questions in Appendix B, (as amended on a case-specific basis to reflect the contents of the SAR), will be posted for stakeholder review and response.

2) The responses will be evaluated and consolidated into the CIA report and submitted to the SC and to the SDT for informational purposes. The CIA report will be posted as part of a standard's development record.

3) The SDT in conjunction with the NERC Standards Development Advisor will initiate the CEA phase (Phase 2 of the CEAP). The CEA phase will typically be conducted during the first combined formal comment period and ballot.

4) The NERC Standards Development Advisor, will complete the CEAP Process Control Document (see Appendix A for template) outlining the expectations for the development of the final CEAP report. The NERC Standards Development Advisor will use the CEAP Process Control document to provide oversight of the CEA.

5) Under the guidance of the NERC Standards Development Advisor and the CEAP Process Control document the SDT will develop a set of survey questions using the template in Appendix B (as amended on a case-specific basis) and adding any other questions that may be necessary to identify the impact (*i.e.*, operational, implementation costs, resources, maintenance costs, ongoing compliance costs, etc.) of the proposed standard's requirements on a requirement by requirement basis. The surveys should be designed such that its results provide:

    i. An indication of what cost impact would be associated with the individual requirements in the standard, if approved.
    ii. An indication of the entities' estimates of what resources and timeframes might be needed to comply with a standard's requirements and provide information on the time the entities might need to implement the requirements of the standard, and develop documentation regarding compliance. This input would consider not only technical but

budgetary concerns. The timeframe would provide further input to the SDT's Implementation Plan.

iii. The identification of potential alternative reliability requirements that could more cost effectively achieve the same reliability objective, and provide justifications, as well as any potential adverse impacts or unintended consequences, if any, that may result directly, or indirectly.

iv. The identification of any market or regulatory issues that may exist and how they could affect the standard's requirements or applicability.

6) The CEA survey questions, along with all pertinent information, will be posted (i) concurrently with the first formal comment period and ballot and (ii) on an as-needed basis to reflect modifications to the proposed reliability standard.

7) Survey results will be evaluated and consolidated into the CEA report with due consideration of any market sensitive information.

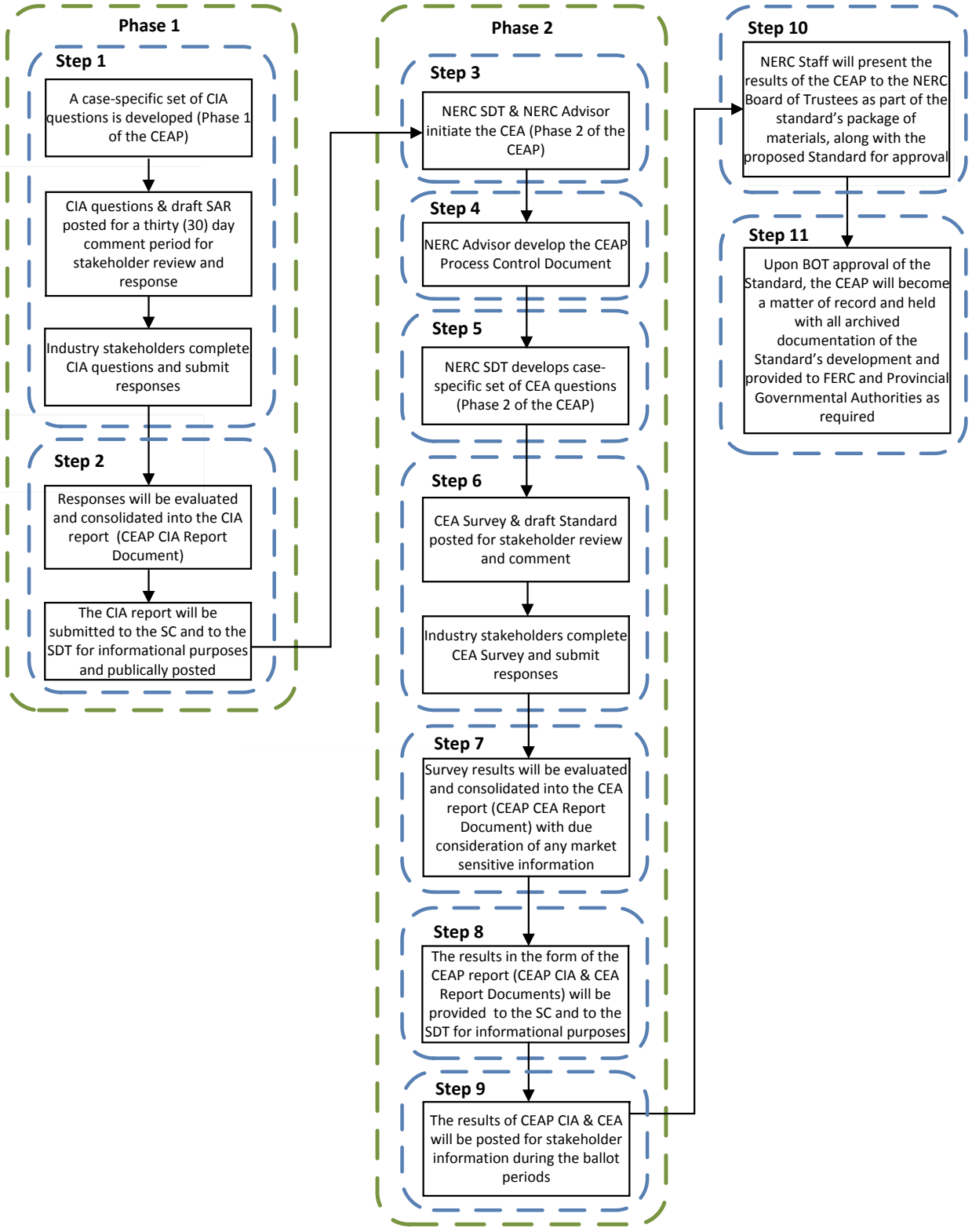
8) Upon completion of the CEA, the results in the form of the CEAP report will be provided to the SC and the SDT for informational purposes. If insufficient responses are received, this will be noted in the CEAP report. The format for the report is set forth in Appendix C of this document.

9) The SC will authorize posting of the CEAP report prior to or concurrent with the successive or recirculation ballot.

10) NERC Staff will present the final CEAP report to the NERC Board of Trustees ("BOT") as part of a standard's package of materials, along with the proposed standard for approval.

11) Upon BOT approval of the standard, the CEAP will become a matter of record and will be held with all archived information in the standard's development record and provided to the FERC and applicable Governmental Authorities as required. The CEAP is informational and is not in itself approved by FERC or the applicable Governmental Authorities.

5.2 Figure 1: CEAP Process Flowchart



5.3 Considerations for the CEAP Report

In developing the reports for Phase 1 of the CEAP ("CIA") and Phase 2 ("CEA") the Standards Committee Process Subcommittee ("SCPS") or other SC designee(s), will utilize any and all available and approved data and tools which may be necessary to extrapolate from incomplete responses, or leverage historical and "snapshot" data and available information to produce an informative report. The CEAP should focus on data related to facilities and other resources and activities subject to the NERC standards.

Items that may be used when developing the report and Staff recommendation may consist of, but not be limited to the following:

i. Adequate Level of Reliability (ALR) Metrics
ii. Transmission Availability Data System (TADS), Generating Availability Data System (GADS) and Demand Response Availability Data System (DADS) databases Filings of the Energy Information Administration EIA411 Form Data which includes information regarding quantities of resources and transmission miles by voltage class
iii. Event, condition, and performance driven indices being developed
iv. Historical Compliance or Event Analysis information
v. Published "Lessons Learned"
vi. Standards Issues Database

Examples of how some of the above may be used, include, but are not limited to, the following;

i. Use of "averaging" when insufficient data may have been submitted by stakeholders. In some instances it may be sufficient to provide a "typical" cost impact for a Transmission Owner with "X" number of miles of transmission, or a Generator capable of "X" MW. Ranges instead of discrete cost impacts such as Transmission Owners' costs ranged between $X and $Y dollars per miles of transmission may be used. Regional characteristics will be taken into consideration to ensure that "averaging" does not produce a misleading perception of results.
ii. Extrapolating when insufficient data may have been submitted by stakeholders by determining total Generation or Transmission circuit miles by voltage class and estimating from the responses given total potential industry cost impact. Energy Information Administration EIA411 Data that NERC currently compiles could provide this "total" data and submitted data could be extrapolated to arrive at approximate industry cost impact.
iii. If the evaluation required extrapolation, estimation or averaging of data to provide useful information, the methods will be documented in the CEAP report for reference.

Data characteristics could include:

- Transmission Owner/Transmission Operator – Approximate miles of transmission lines. (Number of interconnections?) (Number of Stations?)
- Generator Owner/Generator Operator – Aggregate gross capacity of generation resources (MVA).
- Load Serving Entity/Distribution Provider – Peak loading (MW).
- Reliability Coordinator/Balancing Authority/Planning Authority – Approximate miles of transmission lines & aggregate gross capacity of generation resources (MVA).

Appendix A

CEAP Process Control

Draft Standard Title/Project Number _____

Standard Type (i.e. Planning- TPL, Protection-PRC, etc.) _____

Applicability (i.e. TOP, GO, TO, etc.) _____

Suggested Additional Outreach* for Survey-Posting _____

Specific Issues to Address _____

Identification of Market Sensitive or Confidential Issues to Consider for Report _____

_____

* The NERC Standards Development Advisor in conjunction with the SDT will determine if any additional industry outreach is necessary. Additional outreach may include contacting Trade Groups (NAGF, NATF, NRECA, APPA, EEI, ISO/RTO Council, etc.) or specifically impacted entities or segments to encourage their participation in the CEAP process.

CEAP Documentation--SC/NERC Staff Project Management of CEAP (Example only)

The NERC Standards Development Advisor will complete the CEAP Process Control Document outlining the expectations for the development of the final CEAP report. The NERC Standards Development Advisor will use the CEAP Process Control document to provide oversight, management, and documentation of the CEAP.

1) CEAP Phase 1 Cost Impact Analysis (CIA)

Date SAR was Approved for posting by the SC _____

Date Phase 1 CEAP, CIA, Initiated _____

Date of Posting for Comment _____

Date CIA report provided to SC _____

Date SAR was Authorized for Standard Development _____

Date CIA Report Provided to SC and SDT _____

2) CEAP Phase 2 Cost Effectiveness Assessment (CEA)

SC and NERC Staff to Develop CEAP Process Control document, Date Completed

_____

SC Directs NERC Staff to Post Survey for CEA information, (during the first combined formal comment period and ballot) Post Period _____

NERC Staff Compiles CEAP draft Report, Date Provided to SC and SDT

_____

Date Final CEAP report published_____

Date of submission of approved standard and all supporting materials, including Final CEAP report, to the BOT for approval. _____

Appendix B

Sample CIA and CEA Questions

Sample CIA Questions (Additional questions may be included as appropriate):

(Respondents should identify their responses they believe to be CEII, market sensitive, or otherwise confidential.)

1) What approximate incremental one-time and ongoing estimated potential cost impacts are associated with the following: (Please be as specific as possible)

   (a) Implementation costs

   (b) Maintenance costs

   (c) Ongoing Compliance Resource Requirements

2) Are there alternative method(s) or existing reliability standard requirement(s) not identified in the SAR that may achieve the reliability objective? Please explain.

3) Would a technical guideline or "best practices" whitepaper or a training program be effective in achieving a desired outcome to meet the reliability need, as opposed to a "continent-wide" standard? If so, please explain why.

4) What level of reliability related risk exposure of the interconnected transmission network is being addressed by the standard (*i.e.*, High, Medium, or Low)?

Sample CEA Technical Survey Questions (Additional questions may be included as appropriate):

(Respondents should identify their responses they believe to be CEII, market sensitive, or otherwise confidential.)

T-1) Do the requirements in the proposed Reliability Standard collectively achieve the reliability objective of the standard and if not, why?

T-2) Are there alternative method(s) or existing reliability standard requirement(s) not identified in the draft standard which may achieve the draft standard's reliability objective? If so, what alternatives are there and which requirements would they replace?

T-3) On a requirement by requirement basis, does each of the draft requirements, by itself, achieve or contribute to a level of reliability that is "adequate," i.e. acceptable? If so, how? If not, why not?

T-4) Are there additional "efficiencies" that could be realized for any requirement(s)? If so, which requirements, what "efficiencies," and how might they be realized?

T-5) Is there any adverse impact to reliability or any other existing NERC standard, Regional standard, Regional criteria, or in-process project draft standard(s), of which your organization is aware?

T-6) What level of reliability related risk exposure of the interconnected transmission network is being addressed by this standard? (i.e. High, Medium, or Low)

Sample CEA Cost and Implementation Questions (SDT may include additional questions as appropriate):

(Respondents should identify their responses they believe to be CEII, market sensitive, or otherwise confidential.)

CI-1) Describe the size of your organization in broad general terms, e.g. GO-Total installed MWs, TOs circuit miles by kV and total load served, etc.

CI-2) Please answer the following regarding the estimated costs and benefits of each of the proposed requirements:

CI-2a) What are the initial one time, ongoing, implementation, and maintenance costs of complying with the requirements?

CI-2b) What is the on-going long term cost impact (after implementation) of complying with the requirements in terms of equivalent full time employees (EFTE)?

CI-2c) What are the resource benefits (labor, materials, administrative) of implementing these requirements?

CI-2d) What are the reliability benefits of implementing these requirements?

CI-3) Are there alternative method(s) or existing reliability standard requirement(s) not identified in the draft standard which may achieve the reliability objective of the standard that may result in less cost impact (implementation, maintenance, and ongoing compliance resource requirements)? If so what? Please provide as much additional supporting evidence as possible.

CI-4) How long would it take your organization to implement full compliance to the standard as written? What would affect the implementation (i.e. outage scheduling, availability of materials, human resources, etc.)?

CI-5) Would a technical guideline or “best practices” whitepaper or a training program be effective in achieving a desired outcome to meet the reliability need, as opposed to a “continent-wide” standard or variance?

Appendix C

CEAP Report Document Format

The final CEAP Report should be provided in consideration of the following:

i. The total of number of respondents, their cost impacts and their capacities(relative sizes) with due consideration given to market sensitivities.
ii. Ranges or discrete cost impact per MW or circuit mile of transmission or some other factor that industry can utilize to determine an approximation for their cost impact.
iii. Total industry wide potential implementation cost impact for entities.
iv. Effectiveness of the requirements to meet the reliability objective of the standard.
v. Basis for need of the standard as identified in the CIA Phase One of the project based on probabilities of occurrence, potential severity of impact to the BES and reliability need (event, condition or performance driven).
vi. List of any alternatives considered that may have been proposed by stakeholders and not accepted by the SDT along with reasons.
vii. List any assumptions or extrapolations that may have been presented in the report which may affect the results.

If the industry responses were insufficient to provide the SC and SDT with meaningful guidance, efforts will be made to extrapolate without drawing conclusions, clearly identifying where this extrapolation may have been done in the final report.

The approach described poses questions and provides aggregated results in the form of a report to the industry for informational purposes during balloting. The report will take into consideration market sensitivities and the confidentiality of the individual responses and the respondents.

In addition, information in the final posted report will be based on the total number of respondents with due regard to geographic and topological reliability impacts. Upon authorization, the report will be posted along with the NERC standard during balloting**.**

CEAP Phase 1 Cost Impact Analysis (CIA) Report

I. Draft Standard Title/Project Number

II. Executive Summary

III. Standard Type (i.e. Planning- TPL, Protection-PRC, etc.)

IV. Functional Entity Applicability

V. Survey Participants

- a. Analysis of Participants
  - i. Functional Entities (quantity of each type of entity)
  - ii. Relative Sizes (e.g., miles of transmission by class, etc.)
  - iii. Geographic Locations (e.g., region, interconnections, countries, etc.)
- b. Graphical Depiction of Results

VI. CEAP Phase 1 CIA

- a. Reliability Benefit Analysis
  - i. Reliability Related Survey Questions
    1. Assumptions
    2. Data Analysis
  - ii. Results
- b. Cost Impact Analysis
  - i. Cost Related Survey Questions
    1. Assumptions
    2. Data Analysis
  - ii. Graphical Depictions of Results

VII. Conclusions for Phase 1 CIA

CEAP Phase 2 Cost Effectiveness Analysis (CEA) Report

I. Draft Standard Title/Project Number
II. Executive Summary
III. Standard Type (i.e. Planning- TPL, Protection-PRC, etc.)
IV. Functional Entity Applicability
V. Survey Participants
    a. Analysis of Participants
        i. Functional Entities (quantity of each type of entity)
        ii. Relative Sizes (e.g., miles of transmission by class, etc.)
        iii. Geographic Locations (e.g., region, interconnections, countries, etc.)
    b. Graphical Depiction of Results
VI. CEAP Phase 2 CEA
    a. Standard/Requirement Technical Analysis
        i. Technical Survey Questions
            1. Assumptions
            2. Data Analysis
        ii. Results
    b. Cost and Implementation Analysis
        i. Cost and Implementation Survey Questions
            1. Assumptions
            2. Data Analysis
        ii. Graphical Depictions of Results
VII. Conclusions for Phase 2 CEA

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Cost Effective Analysis Process (CEAP) For NERC ERO Standards

October 1, 2012

RELIABILITY | ACCOUNTABILITY

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Suite 600, North Tower
Atlanta, GA 30326
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CEAP Phase 2 Cost Effectiveness Analysis (CEA) Report 17

1. Introduction

Cost considerations are inherent in the development of Reliability Standards. One of the objectives of the NERC Cost Effective Analysis Process ("CEAP" or "Process") is to make such considerations transparent and to ensure that where decisions on Reliability Standards are made regarding cost effectiveness, these decisions are made in an open manner and are part of the standard development record.

While the reliability benefit of any one particular Reliability Standard may be small, taken together, the full battery of standards form a coherent and interdependent whole that helps ensure the reliability of the North American Bulk Power System ("BPS").Understanding the implementation costs and continuing costs of meeting compliance obligations for standards is vital to the development of these standards. Additionally, it is beneficial to industry stakeholders to identify and utilize the most cost effective methods of achieving the standards reliability objective and to afford the same industry stakeholders the ability to propose alternative methods of achieving the reliability objectives.

Regulatory authorities, federal, state and provincial, as well as the NERC Board of Trustees, Regional Entities and electric industry stakeholders have all expressed interest in a process to determine effectiveness and implementation costs of proposed or revised standards to improve reliability of facilities, resources and activities subject to NERC standards. The CEAP will also contribute to the record of standard development and become an integral part of filings with regulatory authorities providing additional needed information and justifications for the standards. Inclusion of implementation costs will also provide a sound basis to assist regulators in satisfying requirements for data that must accompany, and appear in, rulemakings (e.g. the Regulatory Flexiblity Act and Office Management and Budget requirments).

The foundation for this document was the Northeast Power Coordinating Council (NPCC) CEAP which was developed to address the NPCC Board of Director's concerns about implementation costs. The NPCC CEAP was effectively piloted and proved beneficial and has served to provide the concepts found in this NERC CEAP Guideline.

2. Purpose

The CEAP and associated implementation plan represent an initial effort towards addressing concerns regarding cost impacts (*e.g.,* implementation, maintenance, and ongoing compliance resource requirements) associated with achieving reliability objectives for facilities, resources and activities subject to NERC standards.

The purpose of the CEAP is to establish guidelines for the solicitation of input and high level data from the industry, as part of and during the standards development process, to identify more cost effective ways to achieve the same or better reliability outcomes at equal or lower costs. The CEAP is intended to allow the industry the opportunity during the drafting process to identify alternative requirements or methods for meeting a standard's reliability objective that may be (i) less costly or (ii) equally or more effective, or (iii) more efficient. The CEAP, conducted in parallel with the drafting process, should not significantly delay the development of the standard and will add supporting information and background for the NERC stakeholders, the NERC Board of Trustees, and Federal, Provincial and State Regulatory Agencies to be utilized for decision-making.

The CEAP is not intended to provide a comprehensive cost impact or benefit analysis. The CEAP is a guideline to be used for information gathering purposes only and is intended to collect beneficial data, not previously available during standards development. The CEAP is intended to augment and contribute to the efficiency and effectiveness of reliability standards and not delay or obstruct their development.

3. Process Overview

The CEAP will be conducted in two phases. Phase 1, Cost Impact Analysis ("CIA"), and Phase 2, Cost Effectiveness Analysis ("CEA"). Each phase of the CEAP will consist of a set of surveys with questions to be responded to by the industry.

The CEAP Final Report will consist of the (1) CEAP Phase 1 CIA Report and, (2) all combined CEAP Phase 2 CEA Reports.

The CEAP process will result in the production and publication of a CEAP Report, to be archived on the NERC website with the documentation related to the development of the standard.

3.1 Phase 1 Cost Impact Analysis (CIA)

Phase 1 will typically be conducted in conjunction with the Standards Authorization Request ("SAR") stage of a standard's development. The CIA is intended to collect estimated industry wide cost impacts (implementation, maintenance, and ongoing compliance resource requirements) and will evaluate potential reliability benefits of a proposed draft reliability standard. The CIA proposes an analysis of potential areas for coordination and efficiency gains in the development of proposed standards. The CIA will provide a high level "snapshot" of estimated cost impacts and mitigated reliability risks of the proposed reliability standard by soliciting input from stakeholders.

Questions posed during the Phase 1 CIA will focus on potential cost impacts and reliability risks to determine if the standard, in the view of stakeholders, would achieve or possibly exceed an Adequate Level of Reliability ("ALR"). Cost information collected in this phase should be "order of magnitude costs" to determine if a proposed standard will have excessive costs associated with it.

3.2 Phase 2 Cost Effectiveness Analysis (CEA)

The purpose of the CEA is to provide information about cost impacts (*e.g.*, implementation, maintenance, and ongoing compliance resource requirements) of draft reliability standards and their relative effectiveness, which will allow the industry to evaluate and propose alternative approaches for achieving the reliability objectives of the standard. Phase 2 will typically be conducted at the time of the first combined Formal Comment period and Ballot.

The CEA will involve two sets of survey questions which will be asked concurrently. The first set relates to technical feasibility and effectiveness of the proposed requirements as well as soliciting possible more cost effective alternatives to achieve the reliability objectives. The second set of questions will solicit cost impacts (*e.g.*, implementation, maintenance, and ongoing compliance resource requirements) and any related implementation information.

3.3 Cost Effective Analysis Process (CEAP) Report

All information provided during the CIA and CEA phases of the CEAP will be consolidated and evaluated to produce a CEAP report. The CEAP report will be provided to the NERC Standards Committee ("SC") and to the Standard Drafting Team ("SDT") for informational purposes.

All available resources will be utilized effectively and efficiently to produce a CEAP report in a timely manner that does not create unnecessary delays to the standards development process. It must be emphasized that the purpose of the CEAP is not to provide impediments to the NERC standard development process, but rather to inform stakeholders and decision makers of proposed industry cost impact and provide an opportunity for suggestions of alternate methods to achieve equally effective

reliability goals and objectives that may result in less costly implementation. The final report is not intended to be analytical in nature but to promote better judgment and decision-making.

4. Confidentiality

All of the cost impact information submitted by entities will be reviewed and compiled prior to being made public, or presented to the SC and the SDT. The collection, review and compilation of information will be performed in conformance to all applicable requirements of Section 1500 of the NERC Rules of Procedure. Market sensitive issues of individual stakeholders may exist or be provided through the responses to the CEAP questions. All necessary confidentiality will be maintained, and no market sensitive information or Critical Energy Infrastructure Information ("CEII") will be included in the final public report. Responders should identify confidential CEII or market sensitive information in their responses.

5. Process Details

5.1 NERC CEAP Process (See Figure 1: CEAP Process Flowchart)

1) When a draft SAR is posted for a thirty (30) day comment period, a set of CIA questions (Phase 1 of the CEAP) based on the sample questions in Appendix B, (as amended on a case-specific basis to reflect the contents of the SAR), will be posted for stakeholder review and response.

2) The responses will be evaluated and consolidated into the CIA report and submitted to the SC and to the SDT for informational purposes. The CIA report will be posted as part of a standard's development record.

3) The SDT in conjunction with the NERC Standards Development Advisor will initiate the CEA phase (Phase 2 of the CEAP). The CEA phase will typically be conducted during the first combined formal comment period and ballot.

4) The NERC Standards Development Advisor, will complete the CEAP Process Control Document (see Appendix A for template) outlining the expectations for the development of the final CEAP report. The NERC Standards Development Advisor will use the CEAP Process Control document to provide oversight of the CEA.

5) Under the guidance of the NERC Standards Development Advisor and the CEAP Process Control document the SDT will develop a set of survey questions using the template in Appendix B (as amended on a case-specific basis) and adding any other questions that may be necessary to

identify the impact (*i.e.*, operational, implementation costs, resources, maintenance costs, ongoing compliance costs, etc.) of the proposed standard's requirements on a requirement by requirement basis. The surveys should be designed such that its results provide:

i. An indication of what cost impact would be associated with the individual requirements in the standard, if approved.
ii. An indication of the entities' estimates of what resources and timeframes might be needed to comply with a standard's requirements and provide information on the time the entities might need to implement the requirements of the standard, and develop documentation regarding compliance. This input would consider not only technical but budgetary concerns. The timeframe would provide further input to the SDT's Implementation Plan.
iii. The identification of potential alternative reliability requirements that could more cost effectively achieve the same reliability objective, and provide justifications, as well as any potential adverse impacts or unintended consequences, if any, that may result directly, or indirectly.
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7) Survey results will be evaluated and consolidated into the CEA report with due consideration of any market sensitive information.

8) Upon completion of the CEA, the results in the form of the CEAP report will be provided to the SC and the SDT for informational purposes. If insufficient responses are received, this will be noted in the CEAP report. The format for the report is set forth in Appendix C of this document.

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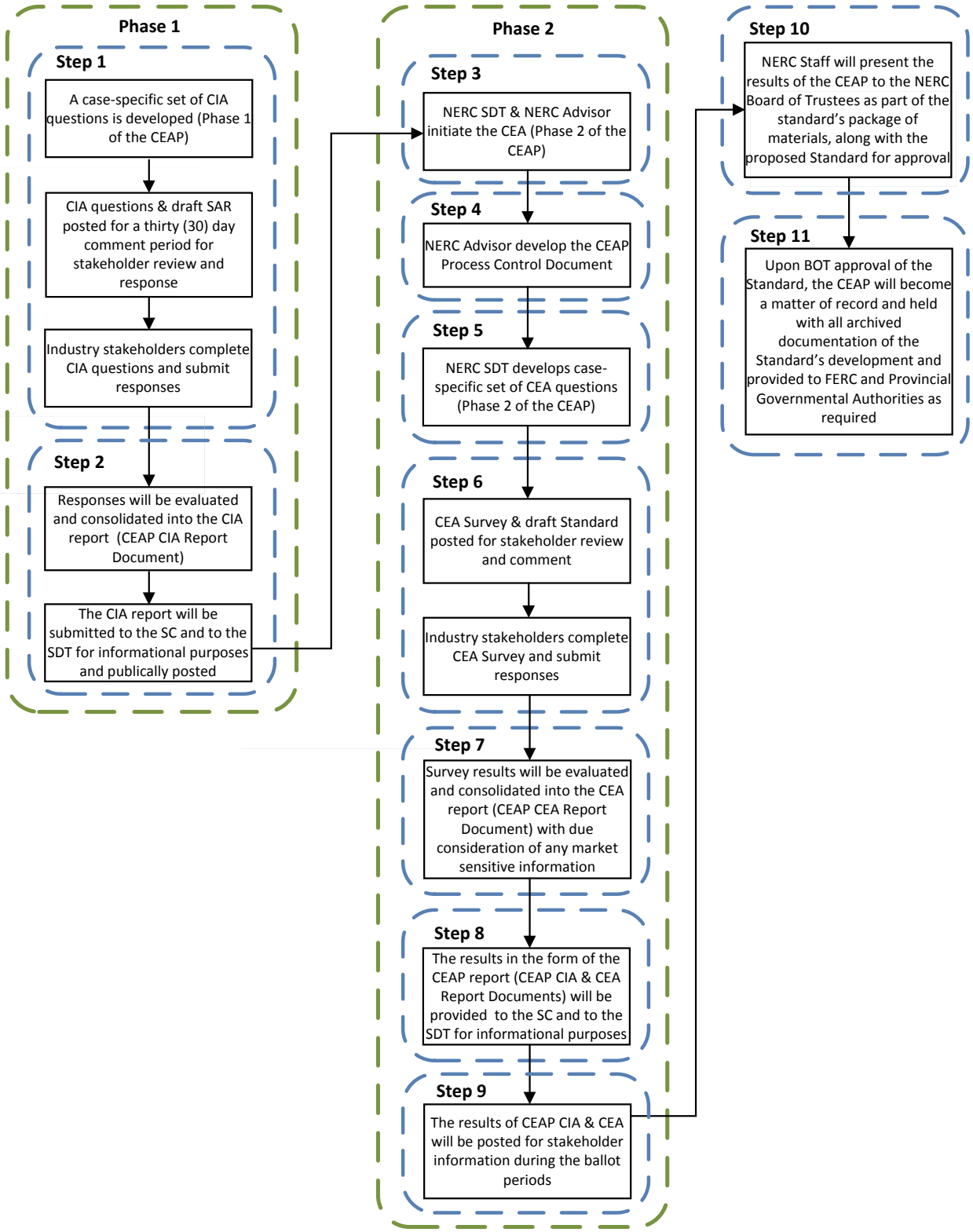
11) Upon BOT approval of the standard, the CEAP will become a matter of record and will be held with all archived information in the standard's development record and provided to the FERC and applicable Governmental Authorities as required. The CEAP is informational and is not in itself approved by FERC or the applicable Governmental Authorities.

5.2 *Figure 1: CEAP Process Flowchart*



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iii. If the evaluation required extrapolation, estimation or averaging of data to provide useful information, the methods will be documented in the CEAP report for reference.

Data characteristics could include:

- Transmission Owner/Transmission Operator – Approximate miles of transmission lines. (Number of interconnections?) (Number of Stations?)

NOTE: The cost difference for overhead vs. underground might require a divided classification of cost, e.g., $X per overhead mile of transmission operated at 200kV and above.

- Generator Owner/Generator Operator – Aggregate gross capacity of generation resources (MVA).

NOTE: Standards may impact different technologies differently. Costs might have to be classified by generation type, e.g., Nuclear $Y per MW, GT's $Z per MW.

- Load Serving Entity/Distribution Provider – Peak loading (MW).
- Reliability Coordinator/Balancing Authority/Planning Authority – Approximate miles of transmission lines & aggregate gross capacity of generation resources (MVA).

Appendix A

CEAP Process Control

Draft Standard Title/Project Number _____

Standard Type (i.e. Planning- TPL, Protection-PRC, etc.) _____

Applicability (i.e. TOP, GO, TO, etc.) _____

Suggested Additional Outreach* for Survey-Posting _____

Specific Issues to Address _____

Identification of Market Sensitive or Confidential Issues to Consider for Report _____

_____

* The NERC Standards Development Advisor in conjunction with the SDT will determine if any additional industry outreach is necessary. Additional outreach may include contacting Trade Groups (NAGF, NATF, NRECA, APPA, EEI, ISO/RTO Council, etc.) or specifically impacted entities or segments to encourage their participation in the CEAP process.

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Date SAR was Approved for posting by the SC _____

Date Phase 1 CEAP, CIA, Initiated _____

Date of Posting for Comment _____

Date CIA report provided to SC _____

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SC and NERC Staff to Develop CEAP Process Control document, Date Completed

_____

SC Directs NERC Staff to Post Survey for CEA information, (during the first combined formal comment period and ballot) Post Period _____

NERC Staff Compiles CEAP draft Report, Date Provided to SC and SDT

_____

Date Final CEAP report published_____

Date of submission of approved standard and all supporting materials, including Final CEAP report, to the BOT for approval. _____

Appendix B

Sample CIA and CEA Questions

Sample CIA Questions (Additional questions may be included as appropriate):

(Respondents should identify their responses they believe to be CEII, market sensitive, or otherwise confidential.)

1) What approximate incremental one-time and ongoing estimated potential cost impacts are associated with the following: (Please be as specific as possible)

   (a) Implementation costs

   (b) Maintenance costs

   (c) Ongoing Compliance Resource Requirements

2) Are there alternative method(s) or existing reliability standard requirement(s) not identified in the SAR that may achieve the reliability objective? Please explain.

3) Would a technical guideline or "best practices" whitepaper or a training program be effective in achieving a desired outcome to meet the reliability need, as opposed to a "continent-wide" standard? If so, please explain why.

4) What level of reliability related risk exposure of the interconnected transmission network is being addressed by the standard (*i.e.*, High, Medium, or Low)?

Sample CEA Technical Survey Questions (Additional questions may be included as appropriate):

(Respondents should identify their responses they believe to be CEII, market sensitive, or otherwise confidential.)

T-1) Do the requirements in the proposed Reliability Standard collectively achieve the reliability objective of the standard and if not, why?

T-2) Are there alternative method(s) or existing reliability standard requirement(s) not identified in the draft standard which may achieve the draft standard's reliability objective? If so, what alternatives are there and which requirements would they replace?

T-3) On a requirement by requirement basis, does each of the draft requirements, by itself, achieve or contribute to a level of reliability that is "adequate," i.e. acceptable? If so, how? If not, why not?

T-4) Are there additional "efficiencies" that could be realized for any requirement(s)? If so, which requirements, what "efficiencies," and how might they be realized?

T-5) Is there any adverse impact to reliability or any other existing NERC standard, Regional standard, Regional criteria, or in-process project draft standard(s), of which your organization is aware?

T-6) What level of reliability related risk exposure of the interconnected transmission network is being addressed by this standard? (i.e. High, Medium, or Low)

Sample CEA Cost and Implementation Questions (SDT may include additional questions as appropriate):

(Respondents should identify their responses they believe to be CEII, market sensitive, or otherwise confidential.)

CI-1) Describe the size of your organization in broad general terms, e.g. GO-Total installed MWs, TOs circuit miles by kV and total load served, etc.

CI-2) Please answer the following regarding the estimated costs and benefits of each of the proposed requirements:

CI-2a) What are the initial one time, ongoing, implementation, and maintenance costs of complying with the requirements?

CI-2b) What is the on-going long term cost impact (after implementation) of complying with the requirements in terms of equivalent full time employees (EFTE)?

CI-2c) What are the resource benefits (labor, materials, administrative) of implementing these requirements?

CI-2d) What are the reliability benefits of implementing these requirements?

CI-3) Are there alternative method(s) or existing reliability standard requirement(s) not identified in the draft standard which may achieve the reliability objective of the standard that may result in less cost impact (implementation, maintenance, and ongoing compliance resource requirements)? If so what? Please provide as much additional supporting evidence as possible.

CI-4) How long would it take your organization to implement full compliance to the standard as written? What would affect the implementation (i.e. outage scheduling, availability of materials, human resources, etc.)?

CI-5) Would a technical guideline or "best practices" whitepaper or a training program be effective in achieving a desired outcome to meet the reliability need, as opposed to a "continent-wide" standard or variance?

Appendix C

CEAP Report Document Format

The final CEAP Report should be provided in consideration of the following:

i. The total of number of respondents, their cost impacts and their capacities(relative sizes) with due consideration given to market sensitivities.
ii. Ranges or discrete cost impact per MW or circuit mile of transmission or some other factor that industry can utilize to determine an approximation for their cost impact.
iii. Total industry wide potential implementation cost impact for entities.
iv. Effectiveness of the requirements to meet the reliability objective of the standard.
v. Basis for need of the standard as identified in the CIA Phase One of the project based on probabilities of occurrence, potential severity of impact to the BES and reliability need (event, condition or performance driven).
vi. List of any alternatives considered that may have been proposed by stakeholders and not accepted by the SDT along with reasons.
vii. List any assumptions or extrapolations that may have been presented in the report which may affect the results.

If the industry responses were insufficient to provide the SC and SDT with meaningful guidance, efforts will be made to extrapolate without drawing conclusions, clearly identifying where this extrapolation may have been done in the final report.

The approach described poses questions and provides aggregated results in the form of a report to the industry for informational purposes during balloting. The report will take into consideration market sensitivities and the confidentiality of the individual responses and the respondents.

In addition, information in the final posted report will be developed by a team with the required subject matter knowledge to be able to analyze and present the data in a useful form. The report will include the total number of respondents with due regard and identification of geographic and topological reliability impacts. Upon authorization, the report will be posted along with the NERC standard during balloting**.**

CEAP Phase 1 Cost Impact Analysis (CIA) Report

I. Draft Standard Title/Project Number

II. Executive Summary

III. Standard Type (i.e. Planning- TPL, Protection-PRC, etc.)

IV. Functional Entity Applicability

V. Survey Participants

- a. Analysis of Participants
  - i. Functional Entities (quantity of each type of entity)
  - ii. Relative Sizes (e.g., miles of transmission by class, etc.)
  - iii. Geographic Locations (e.g., region, interconnections, countries, etc.)
- b. Graphical Depiction of Results

VI. CEAP Phase 1 CIA

- a. Reliability Benefit Analysis
  - i. Reliability Related Survey Questions
    1. Assumptions
    2. Data Analysis
  - ii. Results
- b. Cost Impact Analysis
  - i. Cost Related Survey Questions
    1. Assumptions
    2. Data Analysis
  - ii. Graphical Depictions of Results

VII. Conclusions for Phase 1 CIA

CEAP Phase 2 Cost Effectiveness Analysis (CEA) Report

I. Draft Standard Title/Project Number

II. Executive Summary

III. Standard Type (i.e. Planning- TPL, Protection-PRC, etc.)

IV. Functional Entity Applicability

V. Survey Participants

- a. Analysis of Participants
  - i. Functional Entities (quantity of each type of entity)
  - ii. Relative Sizes (e.g., miles of transmission by class, etc.)
  - iii. Geographic Locations (e.g., region, interconnections, countries, etc.)
- b. Graphical Depiction of Results

VI. CEAP Phase 2 CEA

- a. Standard/Requirement Technical Analysis
  - i. Technical Survey Questions
    1. Assumptions
    2. Data Analysis
  - ii. Results
- b. Cost and Implementation Analysis
  - i. Cost and Implementation Survey Questions
    1. Assumptions
    2. Data Analysis
  - ii. Graphical Depictions of Results

VII. Conclusions for Phase 2 CEA

From:	Guy V. Zito
To:	laura.hussey@nerc.net; pheidrich@frcc.com; smiller@MEAGPOWER.ORG; david.kiguel@HydroOne.com; apusztai@atcllc.com; weslec@pjm.com; smyers@ercot.com; diane.barney@dps.ny.gov; Katherine.Smith@us.ngrid.com; barbara.nutter@nerc.net; michael.lombardi@nu.com; degraffenriedc@coned.com; Joe Tarantino; Steve@wecc.biz; Michael Gildea; Lee R. Pedowicz; Gerard J. Dunbar; Stacey Tyrewala
Cc:	amosher@publicpower.org; ben@benli.ca; lcampbell@frcc.com; david.taylor@nerc.net; Ed Schwerdt
Subject:	Revised NERC CEAP Document and Implementation Plan Whitepaper
Date:	Thursday, September 27, 2012 10:56:19 AM
Attachments:	NERC CEAP DRAFT 09 27 2012.docx Whitepaper on Implementation of CEAP-09.19.2012.docx
Importance:	High

CEAP Team et al,

Attached is the revised draft of the CEAP(minus the cover page due to size restrictions on recipient emails) incorporating points from our meeting with the FERC, your suggestions, and reflective of stakeholders comments received during the posting period. I would like you to send me any further suggested revisions by Friday of this week, Sept. 29th. I would like to gain the NERC SC's approval/endorsement of this and have it available for use by the RISC and the SC if they so choose to implement it. In addition, please also find attached, a revised "scaled down" implementation plan that hopefully will be well received and allow this project to move forward more expeditiously to a field test. Comments on the implementation document are welcome as well by this Friday. I will forward everything to Laura Hussey for inclusion in the SC October meeting material package on Monday and provide the "responses to comments" document for posting on the project page at that time as well.

Thank you all for you participation in this project and as the implementation plan shows, I propose we have some future role in assisting with this important endeavor. Special thanks to Pete Heidrich who provided significant help to me during the past two weeks to bring this closer to the finish line.

Regards,

Guy V. Zito
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1040 Avenue of the Americas, 10 th Floor
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From: Guy V. Zito
Sent: Wednesday, September 26, 2012 10:02 AM
To: David Taylor; laura.hussey@nerc.net; pheidrich@frcc.com; smiller@MEAGPOWER.ORG; david.kiguel@HydroOne.com; apusztai@atcllc.com; weslec@pjm.com; smyers@ercot.com; diane.barney@dps.ny.gov; Katherine.Smith@us.ngrid.com; barbara.nutter@nerc.net; michael.lombardi@nu.com; degraffenriedc@coned.com; Joe Tarantino; Steve@wecc.biz; Michael Gildea; Lee R. Pedowicz; Gerard J. Dunbar; Stacey Tyrewala
Cc: amosher@publicpower.org; ben@benli.ca; lcampbell@frcc.com; Ed Schwerdt
Subject: FERC Chairman Jon Wellinghoff on Right of First Refusal (ROFR) Orders

CEAP Team,

On Sept. 19th The FERC released statements on two denials for rehearings which were filed in response to complaints against PJM and whether a regional planning process has the "right of first refusal" for a project. The proceedings may be found at :

http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20120719-4006

In FERC's deteminination, as outlined in Order 1000 and to paraphrase; The commissions reaffirms it is unjust and unreasonable to grant incumbent transmission providers a federal right of first refusal with respect to certain transmission projects because doing so may result in the failure to consider more efficient or **cost-effective** solutions to regional needs and, in turn, result in the inclusion of higher-cost solutions in the regional plan.

Cost Effectiveness is being further emphasized and is playing a larger role in Commission rulings and activities and I think this is yet another example of the importance to continue to move the NERC CEAP forward towards implementation, even if in a reduced form.

Thanks,

Guy V. Zito
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From: David Taylor [David.Taylor@nerc.net]
Sent: Wednesday, August 29, 2012 10:34 AM
To: Guy V. Zito; laura.hussey@nerc.net; pheidrich@frcc.com; smiller@MEAGPOWER.ORG; david.kiguel@HydroOne.com; apusztai@atcllc.com; weslec@pjm.com; smyers@ercot.com; diane.barney@dps.ny.gov; Katherine.Smith@us.ngrid.com; barbara.nutter@nerc.net; michael.lombardi@nu.com; degraffenriedc@coned.com; Joe Tarantino; Steve@wecc.biz; Michael Gildea; Lee R. Pedowicz; Gerard J. Dunbar; Stacey Tyrewala
Cc: amosher@publicpower.org; ben@benli.ca; lcampbell@frcc.com; Ed Schwerdt
Subject: CEAP Team Meeting - ERCOT Austin - August 29-30, 2012

See the e-mail attached for the file we will be using today.

David W. Taylor
Director Standards Regulatory Initiatives
North American Electric Reliability Corporation
David.Taylor@nerc.net
Cell (609) 651-5089

-----Original Message-----
From: Guy V. Zito [mailto:gzito@npcc.org]
Sent: Friday, August 24, 2012 8:25 PM
To: Laura Hussey; pheidrich@frcc.com; smiller@MEAGPOWER.ORG; david.kiguel@HydroOne.com; apusztai@atcllc.com; weslec@pjm.com; smyers@ercot.com;

diane.barney@dps.ny.gov; Katherine.Smith@us.ngrid.com; Barbara Nutter; michael.lombardi@nu.com; degraffenriedc@coned.com; Joe Tarantino; Steve@wecc.biz; Michael Gildea; Lee R. Pedowicz; Gerard J. Dunbar; David Taylor; Stacey Tyrewala
Cc: amosher@publicpower.org; ben@benli.ca; lcampbell@frcc.com; Ed Schwerdt
Subject: Resend, NERC CEAP Team Meeting - ERCOT Austin - August 29-30, 2012
Importance: High

CEAP Team,

Please respond to me if you are planning on attending next week's meeting in Austin. I am resending the attached meeting logistics and a draft agenda for the subject meeting. Those that are proposing any further changes from Kate and my draft sent out two weeks ago, please bring the proposed revisions to the meeting. I also want to go over the CEAP draft implementation plan and how to move forward with piloting this.

Thanks,

Guy V. Zito
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July 19, 2012Chairman Jon Wellinghoff

STATEMENT

FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos.: ER10-253-001, EL10-14-001, EL10-52-001, ER12-69-000, & ER12-24-000

Item Nos.: E-11, E-12, E-13 & E-14

Statement of Chairman Jon Wellinghoff on Right of First Refusal (ROFR) Orders

"Today's agenda includes several cases related to whether a regional planning process has a right of first refusal, and its impact on transmission development projects.

In E-11 and E-12, the Commission denies requests for rehearing in the complaints filed by Primary Power and Central Transmission, respectively, against PJM. In those cases, we find that PJM's Transmission Owners Agreement does not establish a ROFR as to economic projects and that non-incumbent providers can seek cost recovery under PJM's tariff for those projects.

In contrast, in E-14, *Pioneer v. NIPSCO*, and E-15, *Xcel v. American Transmission Company*, the Commission finds that MISO's Transmission Owners Agreement currently includes a ROFR, and that a proposed transmission line that connects the facilities of two transmission owners will be shared equally by those owners under MISO's TO Agreement, regardless of who initially proposed the line. Although the complainants argued that application of a ROFR in MISO's planning process would be inconsistent with the Commission's findings in Order No. 1000 that it is not just and reasonable, we note that Order No. 1000 applies prospectively, upon acceptance of the parties' compliance filings, which are due in October of this year.

Additionally, in E-13, we deny a complaint brought by Primary Power against PJM for selecting competing projects proposed by incumbent transmission providers. In that case, PJM selected the proposals to construct static var compensators in existing substations by incumbent transmission providers, due to the lower cost.

These orders highlight the very situation that Order No. 1000 is designed to remedy. In Order No. 1000, the Commission stated that it is unjust and unreasonable to grant incumbent transmission providers a federal right of first refusal with respect to certain transmission projects because doing so may result in the failure to consider more efficient or cost-effective solutions to regional needs and, in turn, result in the inclusion of higher-cost solutions in the regional plan. In Order No. 1000-A, the Commission further stated that "expanding the universe of transmission developers offering potential solutions can lead to the identification and evaluation of potential solutions to regional needs that are more efficient or cost-effective." The Commission therefore directed elimination of provisions that establish a federal right of first refusal for an incumbent transmission provider with respect to transmission facilities selected in a regional transmission plan for purposes of cost allocation.

The Commission also provided further guidance in the development of regional transmission planning processes. We note that in Order No. 1000, the Commission required each public utility transmission provider to revise its open access transmission tariff to identify the information that must be submitted by a prospective transmission developer in support of a transmission project that it proposes in the regional transmission planning process. The public utility transmission provider must also provide the date by which such information must be submitted to be considered in a given planning cycle. Each region may determine for itself what deadline is appropriate, including rolling or flexible dates to reflect the iterative nature of its transmission planning process.

The Commission also provided flexibility to regions by stating in Order No. 1000 that the public utility transmission providers may, but are not required to, use competitive solicitation to solicit project or project developers to meet

regional needs. The Commission declined to adopt suggestions to mandate a competitive bidding process. The Commission explained that while it agrees that a competitive process can provide benefits to consumers, it continues to allow public utility transmission providers within each region to determine for themselves, in consultation with stakeholders, what mechanisms are most appropriate to evaluate and select potential transmission solutions to regional needs.

Order No. 1000 further requires public utility transmission providers to implement a planning process that evaluates competing projects in a way that is sufficiently detailed for stakeholders to understand why a particular transmission project was selected or not selected in the regional transmission plan for purposes of cost allocation. By requiring an open and transparent transmission planning process that produces a regional transmission plan, "Order No. 1000 will provide the Commission and interested parties with a record that we believe will be able to highlight whether public utility transmission providers are engaging in undue discrimination against others."

The deadline for filing Order No. 1000 compliance filings is October 11, 2012. We will scrutinize those and related implementation to ensure that Commission-jurisdictional tariffs and agreements are just and reasonable and not unduly discriminatory."

20120719-4006 FERC PDF (Unofficial) 07/19/2012

Document Content(s)

E-11-WELLINGHOFF.DOCX.....1-2

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Whitepaper - Implementation Plan of NERC Cost Effective Analysis Process, "CEAP"

Background

The Cost Effective Analysis Process ("CEAP") was developed in response to requests by NERC registered entities as well as regulators, to address compliance costs and the efficiency and reliability impact of the draft NERC Reliability Standards. The NERC Standards Process Input Group ("SPIG"), under the direction of the NERC Member Representatives Committee ("MRC"), identified cost effectiveness as part of a set of recommendations for improving the NERC standard development process. Upon approval of the SPIG recommendations by the NERC Board of Trustees ("BOT"), an assignment was made to the NERC Standards Committee ("SC") to address SPIG recommendations where appropriate. This *Whitepaper* describes the CEAP and includes a proposed Implementation Plan developed by an industry team working under the auspices of the NERC Standards Committee Process Subcommittee ("SCPS"). The CEAP estimates the implementation costs of a draft Reliability Standard and the effectiveness of the proposed standard if approved and implemented in support of the respective reliability objective.

Executive Summary

Cost considerations are inherent in the development of Reliability Standards. One of the objectives of the CEAP is to make such considerations transparent by ensuring where decisions are made regarding cost effectiveness, these decisions are made in an open manner and are part of the standard development record.

The CEAP affords stakeholders an opportunity to share projected cost information regarding implementation of draft standards and provides the opportunity to offer alternatives that would be equally, or more efficient at achieving the reliability objective of the draft standard while also taking into consideration implementation costs.

The CEAP currently proposes a two-phase process for identifying projected implementation costs. The first phase of the CEAP, identified as the Cost Impact Analysis ("CIA") is conducted during the Standard Authorization Request ("SAR") stage of the standard's development and would provide an opportunity to identify approximate implementation costs that may be associated with a proposed standard prior to its development. Information related to the proposed standard's mission and forecasted implementation costs would typically be collected from the industry during the initial SAR comment period. Information collected would be shared with the NERC Standards Committee ("SC"), Standard Drafting Teams ("SDT"), and will be posted on the NERC website.

The second phase of the CEAP, identified as the Cost Effective Analysis ("CEA"), is typically conducted later in the standards development process after the draft standard is developed by the SDT and is ready for the first combined formal comment period and ballot. In this phase, the industry would again be solicited to provide forecasted implementation costs of the proposed requirements and would be provided the opportunity to propose alternative methods to achieve the standard's reliability objective more efficiently. Any alternative proposals provided by the industry during this phase should contain sufficient technical justification, and if possible, cost comparison data for consideration.

This information will be aggregated, shared with the SDT and made available in the form of a "CEAP Final Report" during successive or recirculation ballots for industry consideration. The CEAP Final Report will then be provided for informational purposes to the NERC Board of Trustees ("BOT") with all other standard background information. Upon approval by the NERC BOT, the standard and the CEAP Final Report will be provided for informational purposes in the filings to applicable regulatory authorities.

The recommended implementation plan for CEAP ideally will include pilot projects for practical experience before a more expansive CEAP implementation. Ultimately, the success of the CEAP depends on the voluntary participation of industry stakeholders.

Recommended CEAP Implementation Plan

The following "Interim Step(s)" will be performed upon SC endorsement of this draft Implementation Plan:

Initial Pilot (Fall 2012/Winter 2013):

1. Immediately upon endorsement of the Implementation Plan, the CEAP Team will review all existing standard projects that are approaching a formal comment and initial ballot and will provide a list of candidates to the SC for potential piloting of the CEAP.
2. The CEAP Team with support from the SDT, when necessary, will develop a limited number of questions that will be added to the "Formal Comment" template for two standards selected for pilot by the SC. Typical questions will focus on:
    i. Identification of forecasted implementation costs of the draft standard.
    ii. More explicit solicitation from the industry to provide alternate ways to equally meet the reliability objective of the draft standard from a long-term implementation perspective, considering implementation costs.
3. Reponses to CEAP survey questions will be collected by NERC Staff and will only be provided to the CEAP Team for evaluation and consolidation. Confidentiality and market sensitive information will be respected and maintained throughout the process.

4. Aggregated information on survey responses related to costs of implementation and alternate methods on addressing this standard (including those alternative costs forecasts) will be made available to the SC and SDTs.
5. The SC and SDT will consider the information collected and take appropriate action which could include revision of the standard or posting of the aggregated summary of information received, with the recirculation ballot. If the SDT decides to revise the standard, then the forecasted costs will be collected again upon successive ballot to create a final record of implementation costs to be posted in conjunction with the recirculation ballot. The question on whether alternative methods of achieving the reliability objective of the Standard will not be solicited at the time of recirculation ballot.

The CEAP Team will develop and propose to the SC a full field test of the CEAP based on the results of the initial pilot and in consideration of any future modifications of the CEAP and the prospective cost effective related responsibilities of the Reliability Issues Steering Committee (RISC). The RISC may assume the responsibilities associated with the CEAP, partially or in its entirety, to address the NERC BOT approved 'SPIG' recommendations regarding the cost of implementation of Reliability Standards.

Proposed Uses of the CEAP

- All new standards development projects - (CIA Phase 1 and CEA Phase 2)
- Revised standards projects
- Standards being revised to meet FERC Directives - Phase 2
- Rapid Revisions - Phase 2 (subject to SC determination)

CEAP will not be applied to the following:

- Errata Changes
- Interpretations and Compliance Application Notices ("CANs")

From: Guy V. Zito
To: rsc
Subject: FW: NERC: Standards Announcement - Standard Process Manual Revisions to Implement SPIG Recommendations - Initial Ballot Results
Date: Tuesday, October 16, 2012 9:38:26 AM

RSC Members,

Initial ballot of the revised Standards Process Manual failed by a small margin. I am currently drafting the responses on behalf of NERC to some of the concerns expressed in the comment period conducted with this ballot. David Kiguel and I will also report at the next RSC meeting on the proceedings at the NERC Standards Committee meeting last week where Gerry Cauley described his vision for standards and how he proposed we achieve that. Also in the coming weeks, Mr. Mark Lauby, who took over for Herb Schrayshuen as Vice President and Director of Standards, will be developing a strategic plan for moving forward with standards development. Initial discussions indicate a very ambitious undertaking of standards development, but retention of the core process. More information to come.

Guy V. Zito
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From: NERC Standards Announcements (Do Not Reply) [mailto:NERC-StandardsAnnouncements-DoNotReply@nerc.net]
Sent: Tuesday, October 16, 2012 9:15 AM
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Standard Process Manual Revisions to Implement SPIG Recommendations - Initial Ballot Results

Standards Announcement

Standard Process Manual Revisions to Implement SPIG Recommendations

Initial Ballot Results

Available Now

An initial ballot for the Standards Processes Manual Revisions concluded on Friday, October 12, 2012.

Voting statistics are listed below, and the Ballots Results page provides a link to the detailed results.

Approval
Quorum: 87.23%
Approval: 63.17%

Next Steps

The Standards Committee Process Subcommittee sub-teams will meet in October to review all comments received and determine what revisions are necessary to finalize the SPM. If no significant changes are made, the SPM will be posted for a recirculation ballot and, if approved by the stakeholder body, presented to the NERC Board of Trustees for approval.

Background

At its February 9, 2012 meeting, the NERC Board of Trustees (BOT) requested the assistance of the NERC Member Representatives Committee (MRC) to provide policy input, and a proposed framework, for specific improvements to the standards development process. The MRC Chair and Vice Chair invited several members of the MRC, two NERC BOT members, the NERC CEO, and the Standards Committee (SC) Chair – the group collectively known as the Standard Process Input Group (SPIG) – to join with them as participants in developing recommendations to improve the standards development process.

To help ensure that the SPIG focused its efforts on the most important areas for improvement, the group began its work by gathering input from subject matter experts, including the regions, the MRC, standard drafting team leaders, NERC staff, and other stakeholders. This input was collected through a series of interviews, supplemented by a formal survey. Based on that input, the SPIG produced a document with five recommendations to modify the way NERC develops Reliability Standards and other solutions intended to improve the priority, product, and process of standards development:

1. **American National Standards Institute (ANSI):** NERC should continue to meet the minimum requirements of the ANSI process to preserve ANSI accreditation.
2. **Reliability Issues Steering Committee (RISC):** The NERC BOT is encouraged to form a RISC to conduct front-end, high-level reviews of nominated reliability issues and direct the initiation of standards projects or other solutions that will address the reliability issues. (Note that the RISC was formed during the August 16 BOT meeting.)
3. **Interface with Regulatory and Governmental Authorities:** The NERC BOT is encouraged to task NERC management, working with a broad array of Electric Reliability Organization resources (e.g., the MRC, technical committees, Regional Entities, trade associations, etc.) to develop a strategy for improving the communication and awareness of effective reliability risk controls to increase input and alignment with state, federal, and provincial authorities.
4. **Standards Product Issues:** The NERC BOT is encouraged to require that the standards development process address the use of results-based standards; cost effectiveness of standards and standards development; alignment of standards requirements/measures with Reliability Standards Audit Worksheets (RSAWs); and the retirement of standards no longer needed to meet an adequate level of reliability.
5. **Standards Development Process and Resource Issues:** The NERC BOT is encouraged to require the standards development process to be revised to improve timely, stakeholder consensus in support of new or revised reliability standards. The BOT is also encouraged to require standard development resources to achieve and address formal and consistent project management and efficient formation and composition of standard drafting teams.

The recommendations also aim to strengthen consensus building, first on the need for a standard, and then on the requirements themselves. Further detail is available in the posted SPIG report.

These recommendations were presented to the BOT and approved on May 9, 2012. The SC was specifically charged with addressing SPIG Recommendations 1, 4, and 5. The SC has organized this effort by leveraging each of its subcommittees, the Process Subcommittee (SCPS) and the Communications and Planning Subcommittee (SCCPS), to work in parallel on developing proposed revisions and conducting outreach to industry stakeholders to ensure that all interested stakeholders have an opportunity to provide their input.

On June 20, 2012, the first draft of SPM revisions was posted for a 30-day stakeholder comment period. The SCPS, supported by NERC staff, has spent the last several weeks reviewing this feedback, revising the proposed SPM as necessary, and responding to stakeholder comments. The proposed revisions to the SPM are included in the posted redline version of the document, and can be summarized as follows:

- Clarification of the requirements for responding to stakeholder comments during informal and formal comment periods
- Retention of the concept of including 'no' ballots that are not accompanied by comments in the calculation of quorum, but not being counted in the calculation of consensus; elimination of the evaluation of comments submitted alongside a 'no' vote to determine relevance
- Clarification of the proposal to move measures from standards to RSAWs
- Removal of the proposal to eliminate VRFs and VSLs from standards
- Clarification of the handling and purpose of interpretations
- Clarification of the intent of the waiver provision in section 16.0

The SC, its subcommittees, and NERC staff are grateful for the industry participation on this project to date, and encourages stakeholders to continue to offer feedback on the proposed SPM revisions so that the SC can deliver a significantly improved process in a timely fashion.

Additional documentation is available on the project page.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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You are currently subscribed to nercroster as: gzito@npcc.org
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From: NERC Standards Announcements (Do Not Reply)
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Standard Process Manual Revisions to Implement SPIG Recommendations - Initial Ballot Results
Date: Tuesday, October 16, 2012 9:47:59 AM

Standards Announcement

Standard Process Manual Revisions to Implement SPIG Recommendations

Initial Ballot Results

Available Now

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Background

At its February 9, 2012 meeting, the NERC Board of Trustees (BOT) requested the assistance of the NERC Member Representatives Committee (MRC) to provide policy input, and a proposed framework, for specific improvements to the standards development process. The MRC Chair and Vice Chair invited several members of the MRC, two NERC BOT members, the NERC CEO, and the Standards Committee (SC) Chair – the group collectively known as the Standard Process Input Group (SPIG) – to join with them as participants in developing recommendations to improve the standards development process.

To help ensure that the SPIG focused its efforts on the most important areas for improvement, the group began its work by gathering input from subject matter experts, including the regions, the MRC, standard drafting team leaders, NERC staff, and other stakeholders. This input was collected through a series of interviews, supplemented by a formal survey. Based on that input, the SPIG produced a document with five recommendations to modify the way NERC develops Reliability Standards and other solutions intended to improve the priority, product, and process of standards development:

1. **American National Standards Institute (ANSI):** NERC should continue to meet the minimum requirements of the ANSI process to preserve ANSI accreditation.
2. **Reliability Issues Steering Committee (RISC):** The NERC BOT is encouraged to form a RISC to conduct front-end, high-level reviews of nominated reliability issues and direct the initiation of standards projects or other solutions that will address the reliability issues. (Note that the RISC was formed during the August 16 BOT meeting.)
3. **Interface with Regulatory and Governmental Authorities:** The NERC BOT is encouraged to task NERC management, working with a broad array of Electric Reliability Organization resources (e.g., the MRC, technical committees, Regional Entities, trade associations, etc.) to develop a strategy for improving the communication and awareness of effective reliability risk controls to increase input and alignment with state, federal, and provincial authorities.
4. **Standards Product Issues:** The NERC BOT is encouraged to require that the standards development process address the use of results-based standards; cost effectiveness of standards and standards development; alignment of standards requirements/measures with Reliability Standards Audit Worksheets (RSAWs); and the retirement of standards no longer needed to meet an adequate level of reliability.
5. **Standards Development Process and Resource Issues:** The NERC BOT is encouraged to require the standards development process to be revised to improve timely, stakeholder consensus in support of new or revised reliability standards. The BOT is also encouraged to require standard development resources to achieve and address formal and consistent project management and efficient formation and composition of standard drafting teams.

The recommendations also aim to strengthen consensus building, first on the need for a standard, and then on the requirements themselves. Further detail is available in the posted SPIG report.

These recommendations were presented to the BOT and approved on May 9, 2012. The SC was specifically charged with addressing SPIG Recommendations 1, 4, and 5. The SC has organized this effort by leveraging each of its subcommittees, the Process Subcommittee (SCPS) and the Communications and Planning Subcommittee (SCCPS), to work in parallel on developing proposed revisions and conducting outreach to industry stakeholders to ensure that all interested stakeholders have an opportunity to provide their input.

On June 20, 2012, the first draft of SPM revisions was posted for a 30-day stakeholder comment period. The SCPS, supported by NERC staff, has spent the last several weeks reviewing this feedback, revising the proposed SPM as necessary, and responding to stakeholder comments. The proposed revisions to the SPM are included in the posted redline version of the document, and can be summarized as follows:

- Clarification of the requirements for responding to stakeholder comments during informal and formal comment periods
- Retention of the concept of including 'no' ballots that are not accompanied by comments in the calculation of quorum, but not being counted in the calculation of consensus; elimination of the evaluation of comments submitted alongside a 'no' vote to determine relevance
- Clarification of the proposal to move measures from standards to RSAWs

- Removal of the proposal to eliminate VRFs and VSLs from standards
- Clarification of the handling and purpose of interpretations
- Clarification of the intent of the waiver provision in section 16.0

The SC, its subcommittees, and NERC staff are grateful for the industry participation on this project to date, and encourages stakeholders to continue to offer feedback on the proposed SPM revisions so that the SC can deliver a significantly improved process in a timely fashion.

Additional documentation is available on the project page.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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From: Kimberly Mielcarek
To: Kimberly Mielcarek
Subject: NERC Statement - Response to Passage of Critical Infrastructure Protection Version 5 Standards
Date: Wednesday, November 07, 2012 1:20:05 PM

Statement

Response to Passage of Critical Infrastructure Protection Version 5 Standards

Click here for Statement

ATLANTA – The electricity industry passed Version 5 of the North American Electric Reliability Corporation's critical infrastructure protection standards with an overwhelming consensus earlier this week. "The industry is to be commended for supporting the CIP Version 5 standards with high approval rates," said Gerry Cauley, president and chief executive officer of the North American Electric Reliability Corporation (NERC). "This effort represents significant prioritization from the industry focused on the importance of cybersecurity."

For more information or assistance, please contact Kimberly Mielcarek.

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Statement

Response to Passage of Critical Infrastructure Protection Version 5 Standards

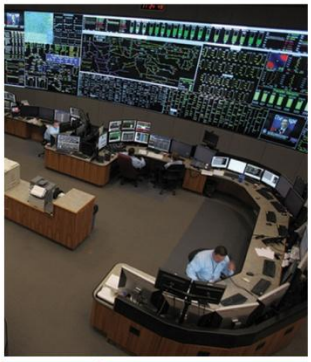
November 7, 2012

ATLANTA – The electricity industry passed Version 5 of the North American Electric Reliability Corporation's critical infrastructure protection standards with an overwhelming consensus earlier this week.

"The industry is to be commended for supporting the CIP Version 5 standards with high approval rates," said Gerry Cauley, president and chief executive officer of the North American Electric Reliability Corporation (NERC). "This effort represents significant prioritization from the industry focused on the importance of cybersecurity."

The Version 5 standards leverage lessons learned from previous CIP versions, providing for categorization of BES Cyber Systems commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the bulk electric system. The standards provide increased flexibility in implementing risk mitigation and security to individual entity operations based on function, connectivity, risk and impact.

NERC will submit Version 5 to the Board of Trustees for approval, after which the standards will be filed with the Federal Energy Regulatory Commission for final approval.



CONTACT:
Kimberly.Mielcarek@nerc.net

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From: NERC Standards Announcements (Do Not Reply)
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement | NERC Server Maintenance December 1, 2012
Date: Tuesday, November 27, 2012 2:38:23 PM

Standards Announcement

To: Members of the NERC Registered Ballot Body

Re: NERC Server Maintenance

NERC is conducting server maintenance on Saturday, December 1st, and our balloting and commenting systems will be unavailable for a portion of time that day. We are providing this information so that people are able to plan to cast their ballots so that the open ballots and comment periods can close on time, since drafting teams have meetings already planned based on the scheduled closing dates.

The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Standards staff

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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Standards Announcement

Project 2012-INT-02 - Interpretation of TPL-003 and TPL-004 for System Protection and Control Subcommittee

Formal Comment Period Open: October 22 – December 5, 2012

Join Ballot Pool: October 22 – November 20, 2012

Upcoming
Initial Ballot: November 26 – December 5, 2012

Now Available

A formal comment period for the interpretation of **TPL-003-0a** – System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) and **TPL-004-0** – System Performance Following Extreme Events Results in the Loss of Two or More Bulk Electric System Elements (Category D) is open through 8 p.m. Eastern on **Wednesday, December 5, 2012.**

Instructions for Joining Ballot Pool(s)

A ballot pool is being formed. Registered Ballot Body members must join the ballot pool to be eligible to vote in the balloting of the interpretations for TPL-003-0a and TPL-004-0. Registered Ballot Body members may join the ballot pool by 8 a.m. ET on November 20, 2012 at the following page: Join Ballot Pool

During the pre-ballot window, members of the ballot pool may communicate with one another by using the "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.) The ballot pool list server for this ballot pool is:

bp-2012-INT-02_TPL3_4_in@nerc.com

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Wednesday, December 5, 2012.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please read carefully: All stakeholders with comments (both members of the ballot pool as well as other stakeholders, including groups such as trade associations and committees) must submit

comments through the electronic comment form. During the ballot window, balloters who wish to submit comments with their ballot *may no longer enter comments on the balloting screen*, but may still enter the comments through the electronic comment form. Balloters who wish to express support for comments submitted by another entity or group will have an opportunity to enter that information and are not required to answer any other questions.

Next Steps

An initial ballot will be conducted November 26 through 8 p.m. Friday, December 5, 2012

Background

Order No. 754, issued September 15, 2011, was the Final Rule approving the Interpretation of TPL-002-0a for PacifiCorp (Project 2009-14) regarding requirement R1.3.10. In addition to the approval, the Commission expressed a concern (Para 19 and 20) about single point of failure of protection systems and issued NERC a directive for further investigation. This request for interpretation submitted by the System Protection and Control Subcommittee (SPCS) is one of three approaches aimed to address the concern. The SPCS is seeking clarification in two areas in TPL-003-0a (Category C) and TPL-004-0 (Category D). The first regarding the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "(stuck breaker or protection system failure)." Second, to what extent does the description in the standards' Table 1, footnote (e) require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system.

Additional information is available on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Development Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Response for Interpretation of TPL-003 and TPL-004 for SPCS

When completed, email this form to:
laura.hussey@nerc.net
For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

Note: A valid interpretation request is one that requests additional clarity about one or more requirements in approved NERC reliability standards, but does not request approval as to how to comply with one or more requirements.

Request for an Interpretation of a Reliability Standard			
Date submitted:	December 12, 2011		
Contact information for person requesting the interpretation.			
Name:	Jonathan Sykes (PG&E), Chairman SPCS		
Organization:	NERC System Protection & Control Subcommittee		
Telephone:	(510) 874-2691	**E-mail:**	jfst@pge.com

Identify the Standard (include version number, e.g., PRC-001-1) that needs clarification and its associated title.	
Standard	Title
TPL-003-0a	System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
TPL-004-0	System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Identify specifically what Requirement needs clarification.	
Standard	Requirement (and text)
TPL-003-0a	**R1.3.1** Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system

	results shall be available as supporting information.
TPL-003-0a	**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-003-0a	**R1.5.** Consider all contingencies applicable to Category C.
TPL-004-0	**R1.3.1.** Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-004-0	**R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	**R1.4.** Consider all contingencies applicable to Category D.

Identify the nature of clarification that is requested (Check as many as applicable).

- ☒ Clarify the required performance
- ☐ Clarify the conditions under which the performance is required
- ☐ Clarify which functional entity is responsible for performing an action in a requirement
- ☐ Clarify the reliability outcome the requirement is intended to produce

Please explain the clarification needed.

This interpretation request has been developed to address Commission concerns related to the term "Single Point of Failure" and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an Industry Advisory — Protection System Single Point of Failure[1] (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

Question 1: For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[2] of either "stuck breaker" or "protection system failure" contingency[3], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1[4] requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

Question 2: For the phrase "Delayed Clearing[5]" used in Category C[6] contingencies 6-9 and Category D[7] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[8] require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on

[1] NERC Website: (http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf)

[2] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

[3] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

[4] "*Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts*."

[5] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

[6] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

[7] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

[8] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"

the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase "Delayed Clearing" used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term "Delayed Fault Clearing." While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to "stuck breaker" or "protection system failure" contingency assessments.

Identify the material impact to your organization or others, if known, caused by the lack of clarity or an incorrect interpretation of this standard.

There is a material impact to the entities required to perform transmission planning assessments and to the entities that may rely on these assessments. The lack of clarity in defining the required studies impacts entities by:

- Potential non-compliance if the correct contingencies are not studied
- Inefficient use of resources if contingencies are studied that are not required and mitigation plans are implemented that are not required
- Potential negative impact to grid reliability if the correct contingencies are not assessed

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee
The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.37 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

Standard	Requirement (and text)
TPL-003-0a	**R1.3.1** Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-003-0a	**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-003-0a	**R1.5.** Consider all contingencies applicable to Category C.
TPL-004-0	**R1.3.1.** Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-004-0	**R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	**R1.4.** Consider all contingencies applicable to Category D.

Question 1
For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of

evaluating the effects[9] of either "stuck breaker" or "protection system failure" contingency[10], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

Response 1

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must consider the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, ~~TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (~~Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. Evaluation of a single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3~~Three~~-phase (3ø) (TPL-004-0, Table I, Category D) Fault with delayed clearing is required and further defined by footnote (e) and the parenthetical phrase "(~~"~~stuck breaker or protection system failure)."~~."~~ Footnote (e) explains that "Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay." The parenthetical further emphasizes that the failure may be a "stuck breaker or protection system failure" that causes the delayed clearing of the fault. The ordered reading of the text in Table 1 in either standard explains that delayed clearing caused by a failure of a protection system or circuit breaker must be evaluated to examine its impact on BES performance. ~~Therefore, the transmission planner must consider the situation that produces the more severe system results or impacts due to a delayed clearing condition regardless whether the condition resulted from either a stuck breaker or protection system failure.~~

Standard	Requirement (and text)
TPL-003-0a	**R1.3.1** Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-003-0a	**R1.3.10.** Include the effects of existing and planned protection systems, including

[9] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

[10] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

	any backup or redundant systems.
TPL-003-0a	**R1.5.** Consider all contingencies applicable to Category C.
TPL-004-0	**R1.3.1.** Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-004-0	**R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	**R1.4.** Consider all contingencies applicable to Category D.

Question 2

For the phrase "Delayed Clearing[11]" used in Category C[12] contingencies 6-9 and Category D[13] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[14] require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

Response 2

The term "Delayed Clearing" that is described in Table I~~1~~, footnote (e) refers to fault clearing that results from a failure to achieve the protection system's normally expected clearing time. The Planning Authority and Transmission Planner is permitted engineering judgment in its Category C or D contingencies to select the~~Any failure of a~~ protection system component failures for evaluation that would produce the more severe system results or impact (R1.3.1) and this would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts ~~increases clearing times of~~ one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner ~~and Planning Authority~~ to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

[11] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

[12] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

[13] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

[14] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"

The interpretation drafting team bases this conclusion on the footnote (e) example "…any protection system component such as, relay, circuit breaker, or current transformer…" because the component "circuit breaker" is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of "protection system" inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team's further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, "Protection System," the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

Revision History (To be removed upon Final)

Version	Date	Description
1.0	5/9/2012	Draft 1 of the response to the request for interpretation.
2.0	10/16/2012	Draft 2 of the response to the request for interpretation.

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Interpretation Request Form
2012-INT-02 TPL-003-0a and TPL-004-0

When completed, email this form to:
laura.hussey@nerc.net
For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

Note: A valid interpretation request is one that requests additional clarity about one or more requirements in approved NERC reliability standards, but does not request approval as to how to comply with one or more requirements.

Request for an Interpretation of a Reliability Standard			
Date submitted:	December 12, 2011		
Contact information for person requesting the interpretation.			
Name:	Jonathan Sykes (PG&E), Chairman SPCS		
Organization:	NERC System Protection & Control Subcommittee		
Telephone:	(510) 874-2691	**E-mail:**	jfst@pge.com

Identify the Standard (include version number, e.g., PRC-001-1) that needs clarification and its associated title.	
Standard	**Title**
TPL-003-0a	System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
TPL-004-0	System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Identify specifically what Requirement needs clarification.	
Standard	**Requirement (and text)**
TPL-003-0a	**R1.3.1** Be performed and evaluated only for those Category C contingencies that

	would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-003-0a	**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-003-0a	**R1.5.** Consider all contingencies applicable to Category C.
TPL-004-0	**R1.3.1.** Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-004-0	**R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	**R1.4.** Consider all contingencies applicable to Category D.

Identify the nature of clarification that is requested (Check as many as applicable).

- ☒ Clarify the required performance
- ☐ Clarify the conditions under which the performance is required
- ☐ Clarify which functional entity is responsible for performing an action in a requirement
- ☐ Clarify the reliability outcome the requirement is intended to produce

Please explain the clarification needed.

This interpretation request has been developed to address Commission concerns related to the term "Single Point of Failure" and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the

evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an Industry Advisory — Protection System Single Point of Failure[1] (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

Question 1: For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[2] of either "stuck breaker" or "protection system failure" contingency[3], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1[4] requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

Question 2: For the phrase "Delayed Clearing[5]" used in Category C[6] contingencies 6-9 and Category D[7] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[8] require an entity to

[1] NERC Website: (http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf)

[2] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

[3] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

[4] "*Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts*."

[5] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

[6] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

[7] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase "Delayed Clearing" used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term "Delayed Fault Clearing." While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to "stuck breaker" or "protection system failure" contingency assessments.

Identify the material impact to your organization or others, if known, caused by the lack of clarity or an incorrect interpretation of this standard.

There is a material impact to the entities required to perform transmission planning assessments and to the entities that may rely on these assessments. The lack of clarity in defining the required studies impacts entities by:

- Potential non-compliance if the correct contingencies are not studied
- Inefficient use of resources if contingencies are studied that are not required and mitigation plans are implemented that are not required
- Potential negative impact to grid reliability if the correct contingencies are not assessed

[8] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-0a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 23, 2010

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	July 30, 2008	Adopted by NERC Board of Trustees	
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0a	April 23, 2010	FERC approval of interpretation of TPL-003-0 R1.3.12	Interpretation

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-0

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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Standards Announcement

Project 2013-02 Paragraph 81

Formal Comment Period Now Open: October 25 – December 10, 2012
Ballot Pool Forming Now: October 25 – November 23, 2012

Upcoming
Initial Ballot: November 30 – December 10, 2012

Now Available

The Paragraph 81 (P81) standard drafting team (SDT) has posted a single PDF containing redlined versions of 27 standards showing 38 requirements proposed to be retired, and an implementation plan for a formal comment period and initial ballot that will end at 8 p.m. Eastern on Monday, December 10, 2012. A ballot pool is being formed and the ballot pool window is open through 8 a.m. Eastern on **Friday, November 23, 2012** (*please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly*).

The following documents are posted on the project page for review and balloting:

- **Redline of Standards with Proposed Retirements** – A PDF document containing a redline of each of the affected standards, indicating the requirements and associated elements proposed to be retired with a "(Retired)" and with the version number remaining the same. When these Requirements are retired, the version numbers of the standards will NOT be incremented. After evaluating the options and consulting with the Standards Committee and Standards Committee Process Subcommittee, the P81 drafting team determined that this was the most practical approach. Incrementing the version numbers of each standard is impractical because, in some cases, a subsequent version has already been developed. In addition, incrementing the version would require renumbering Requirements where a retired Requirement created a gap in numbering, and this creates an undesirable administrative burden for entities using certain systems to manage their compliance programs.
- **Implementation Plan** – The implementation plan for retiring the Phase I requirements.

The following documents are posted on the project page as Supporting Materials to assist stakeholders in their review:

- **Final SAR (clean and redline)** – The final SAR incorporates revisions to the draft SAR by the P81 SDT in response to comments received from the industry.
- **Technical White Paper** – The technical white paper includes the technical justification developed by the P81 SDT to support the retirement of the proposed requirements in Phase I.

- **Redline of VSL Matrix** – This identifies the VSLs (and parts of VSLs) that will be retired when the requirements in Phase I are retired. The matrix may be useful in providing a complete view of the VSLs and parts of VSLs that will be retired when a particular Requirement is retired, since some of the early standards have not had the FERC-approved VSLs incorporated in the standard.
- **Spreadsheet with Proposed Retirements** – This spreadsheet includes a list of the requirements proposed in the draft SAR and their status in the final SAR (kept in final SAR for retirement, kept in final SAR for information only, deferred to subsequent phase). Additionally, the spreadsheet includes requirements that were added to the Phase I list as a result of industry comments on the draft SAR, which are identified as 'added to final SAR for retirement.'
- **Unofficial Comment Form (Word)** – A Word version of the comment form for the development of internal draft responses only (the final must be submitted electronically).

Instructions for Joining Ballot Pool(s)

Registered Ballot Body members must join the ballot pool to be eligible to vote in balloting of the requirements being proposed for retirement. A single ballot pool is being formed, and all of the standards with Requirements being proposed for retirement will be balloted as a group. Registered Ballot Body members may join the ballot pool at the following page: Join Ballot Pool

During the pre-ballot window, members of the ballot pool may communicate with one another by using the "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.) The ballot pool list server for this ballot pool is: bp-2013-02_P81_in@nerc.com.

The ballot pool is open **through 8 a.m. Eastern on Friday, November 23, 2012.**

Instructions for Commenting

A formal comment period is open through 8 p.m. Eastern on **Monday, December 10, 2012**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

A single ballot for all of the standards with Requirements being proposed for retirements will be conducted Friday, November 30, 2012 through 8 p.m. Monday December 10, 2012.

Background

On March 15, 2012, the Federal Energy Regulatory Commission (FERC) issued an order on NERC's Find, Fix and Track process that stated the following in P81:

> "The Commission notes that NERC's FFT initiative is predicated on the view that many violations of requirements currently included in Reliability Standards pose lesser risk to the Bulk-Power System. If so, some current requirements likely provide little protection for Bulk-Power System reliability or may be redundant. The Commission is interested in obtaining views on whether such requirements could be removed from the Reliability Standards with little effect on reliability and an increase in efficiency of the ERO compliance program. If NERC believes that specific Reliability Standards or specific requirements within certain Standards should be revised or removed, we invite NERC to make specific proposals to the Commission identifying the Standards or requirements and setting forth in detail the technical basis for its belief. In addition, or in the alternative, we invite NERC, the Regional Entities and other interested entities to propose appropriate mechanisms to identify and remove from the Commission-approved Reliability Standards unnecessary or redundant requirements. We will not impose a deadline on when these comments should be submitted, but ask that to the extent such comments are submitted NERC, the Regional Entities, and interested entities coordinate to submit their respective comments concurrently."

The purpose of the project is to retire or modify FERC-approved Reliability Standard requirements that as FERC noted, "provide little protection to the reliable operations of the BES," are redundant or unnecessary, or to retire or modify a FERC-approved Reliability Standard requirement to increase the efficiency of the ERO's compliance programs.

The draft SAR, which included criteria for retiring or modifying requirements, defined phases for the project, and a suggested list of requirements put together by NERC, the regions, and the trades and their member companies for consideration in Phase I, was posted for an informal comment period. In September, the P81 SDT met to respond to the comments received and finalize the SAR. The revisions resulted in a list of 38 requirements in 23 Reliability Standard versions being proposed for retirement and an additional 13 requirements included for informational purposes only. The P81 SDT also developed a Technical White Paper which includes the justification for retiring the proposed requirements.

To sign up for the plus list for this project to follow along with meetings and work products, please email Kristin Iwanechko.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project 2013-02 Paragraph 81

The Paragraph 81 Drafting Team thanks all commenters who submitted comments on the Project 2013-02 Paragraph 81 - Retirement of Reliability Standard Requirements. The complete set of standards with proposed retirements for Phase 1 were posted for a 30-day public comment period from August 3, 2012 through September 4, 2012. Stakeholders were asked to provide feedback on the set of standards through a special electronic comment form. There were 43 sets of comments, including comments from approximately 98 different people from approximately 65 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

1. Do you agree with the criteria listed in the SAR to identify Reliability Standard requirements for retirement? If not, please explain in the comment area. 8
2. The Initial Phase of the P81 project is designed to identify all FERC-approved Reliability Standard requirements that easily satisfy the criteria. Do you agree that the suggested list of Reliability Standard requirements included in the draft SAR easily satisfy the criteria listed in the draft SAR? If you disagree, please provide a statement supporting what Reliability Standard requirements you would add or subtract from the Initial Phase, including a citation to at least one element of Criterion B, as applicable. 24
3. The subsequent phases of the P81 project are designed to identify all FERC-approved Reliability Standard requirements that could not be included in the Initial Phase due to the need for additional analysis or an editing of language. Please list any Reliability Standard requirements that you believe should be revised or retired in a subsequent phase, and include a brief supporting statement and citation to at least one element of Criterion B for each requirement listed. 67
4. If you have any other comments or suggestions on the draft SAR that you have not already provided in response to the previous questions, please provide them here. 94

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Lee Pedowicz	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Ben Wu	Orange and Rockland Utilities	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Donald Weaver	New Brunswick System Operator	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
18.	Brian Robinson	Utility Services	NPCC	8
19.	Michael Schiavone	National Grid	NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC	5

2.	Group	Jim Kelley	SERC EC Planning Standards Subcommittee	X				X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren	SERC	1
2.	Bob Jones	Southern Company Services	SERC	1
3.	Pat Huntley	SERC	SERC	10
4.	Darrin Church	TVA	SERC	1

3.	Group	Emily Pennel	Southwest Power Pool Regional Entity										X

No additional members listed.

4.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tedd	Snodgrass	WECC	1
2.	Tim	Loepker	WECC	1
3.	Erika	Doot	WECC	3, 5, 6
4.	Alfredo	Bocanegra	WECC	1

5.	Group	Connie Lowe	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade		RFC	5, 6
2.	Mike Garton		NPCC	5, 6
3.	Randi Heise		MRO	5, 6
4.	Mike Crowley		SERC	1, 3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michelle Corley	Cleco Power	SPP	1, 3, 5
2.	Eric Ervin	Westar Energy	SPP	1, 3, 5, 6
3.	Greg Froehling	Rayburn Country Electric Cooperative	SPP	3
4.	Jonathan Hayes	Southwest Power Pool	SPP	2
5.	Louis Guidry	Cleco Power	SPP	1, 3, 5
6.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
7.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
8.	John Mason	City of Independence, MO	SPP	3
9.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
10.	Patrick Smith	Westar Energy	SPP	1, 3, 5, 6
11.	Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

7.	Group	David Thorne	Pepco Holdings Inc & Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mark Godfrey	Pepco Holdings Inc	RFC	1, 3

8.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 5
2.	Scott Brame	North Carolina Electric Membership Corporation	RFC	1, 3, 4, 5
3.	Bill Watson	Old Dominion Electric Cooperative	SERC	3, 4

9.	Group	Mark S. Gray	The Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), the Electric Power Supply Association (EPSA), the Transmission Access Policy Study Group (TAPS), Electricity Consumers Resource Council (ELCON), the American Public Power Association (APPA), the Large Public Power Council (LPPC) and, the Canadian Electricity Association (CEA)	X		X	X	X	X	X	X		

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			(collectively, the Trade Associations).										
www.eei.org/ for members													
10.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Brent Ingebrigtson	LG&E and KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
4.			WECC	5
5.	Elizabeth A. Davis	PPL Energy Plus, LLC	MRO	6
6.			NPCC	6
7.			SERC	6
8.			SPP	6
9.			RFC	6
10.			WECC	6

11.	Group	Steve Rueckert	Western Electricity Coordinating Council											X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Phil O'Donnell	WECC	WECC	10
2.	Brent Castagnetto	WECC	WECC	10
3.	Tim Reynolds	WECC	WECC	10
4.	Tyson Jarrett	WECC	WECC	10

12.	Individual	Bob Steiger	Salt River Project	X		X		X	X					
13.	Individual	Al DiCaprio	SRC		X									
14.	Individual	Ron Donahey	Tampa Electric Company	X		X		X	X					
15.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X					
16.	Individual	Scott McGough	Georgia System Operations Corporation			X	X							
17.	Individual	Ronnie C. Hoeinghaus	City of Garland	X		X								
18.	Individual	Dan Miller	Entergy Services, Inc.	X		X			X					
19.	Individual	Michael Falvo	Independent Electricity System Operator		X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Michelle Clements	Wolverine Power Supply Cooperative, Inc.	X									
21.	Individual	Thomas C. Duffy	Central Husdon Gas & Electric Corporation	X		X							
22.	Individual	John Tolo	Tucson Electric Power	X									
23.	Individual	paul haase	seattle city light	X		X	X	X	X				
24.	Individual	Thad Ness	American Electric Power	X		X		X	X				
25.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
26.	Individual	Jose H Escamilla	CPS Energy	X		X		X					
27.	Individual	Laura Lee	Duke Energy	X		X		X	X				
28.	Individual	Rich Salgo	NV Energy	X		X		X					
29.	Individual	John Falsey	Edison Mission Marketing & Trading					X					
30.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
31.	Individual	Michelle R. D'Antuono	Occidental Energy Ventures Corp.			X		X		X			
32.	Individual	Patrick Brown	Essential Power, LLC					X					
33.	Individual	Becky Stewart	Idaho Power Company	X		X							
34.	Individual	Kimberly Tolbert	Occidental Power Services, Inc.			X							
35.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
36.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
37.	Individual	Eric Olson	Transmission Agency of Northern California	X									
38.	Individual	Kirit Shah	Ameren	X		X		X	X				
39.	Individual	Jason Snodgrass	Georgia Transmission Corporation	X									
40.	Individual	Kristin Iwanechko	NERC Staff Technical Review										
41.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
42.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
43.	Individual	Judy VanDeWoestyne	MidAmerican Energy Company	X		X		X	X				

1. **Do you agree with the criteria listed in the SAR to identify Reliability Standard requirements for retirement? If not, please explain in the comment area.**

Summary Consideration:[2]

The majority of commenters supported the Criteria A, B and C included in the draft SAR, with a few commenters suggesting changes.

A. Comments on Criterion A

The P81 standards drafting team (P81 SDT), in conjunction with NERC's technical staff review, believes it is appropriate to rephrase Criterion A to be similar to Criterion B 9, which comports with the FFT Order, and, at the same time, to eliminate Criterion B 8 and Criterion B 9 to avoid any confusion between Criterion A and Criterion B. The P81 SDT believes the following provides a more suitable overarching Criterion A:

"The Reliability Standard requirement requires responsible entities to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES."

Comments

The Western Electricity Coordinating Council (WECC) and Northeast Power Coordinating Council (NPCC) requested clarification or alternative wording of Criterion A, while Independent Electricity System Operator and NPCC also saw Criterion A and Criterion B 9 as redundant or duplicative. Manitoba Hydro also believed there was a need to clarify Criterion B 9 and Occidental Energy Ventures Corp. desires that Criterion A implicate Section 215 of the Federal Power Act, while Occidental, like others, also believes Criterion B 8 and Criterion B 9 need clarification.

Response

The P81 SDT believes the above revision of Criterion A and elimination of Criterion B 8 and Criterion B 9 addresses the commenters' concerns, while still including the Section 215 term reliable operation.

B. Comments on Criterion B

[2] Although responses to informal comments are not required in the detail found in the P81 SDT responsive comments, the P81 SDT believed it was appropriate to provide more detail given the level of interest in this Standards Development Project. The format and detail of these responses are not precedent setting with respect to how other SDTs respond to an informal comment period.

Comment

WECC states it only agrees with Criterion B 1 if each administrative requirement meets all the sub-requirements listed (administrative in nature, does not support reliability and needlessly burdensome). In addition, ACES Power Marketing Standards Collaborators states that in Criterion B 1 it would be best to strike "and is needlessly burdensome."

Response

The list of requirements was meant to apply to each candidate and uses the term "and" not "or" to ensure all three are required. The wording of Criterion B 1 was carefully considered in the collaborative process, and it was believed that the current wording, which tends to match with WECC's understanding, is appropriate. Thus, the P81 SDT believes that no changes to Criterion B 1 are necessary.

Comment

WECC disagrees with Criteria B 3, B 4 and B 5 unless it may be demonstrated that there is no benefit to reliability at all.

Response

WECC's comment seems misaligned with FERC's intention which the P81 SDT believes was for NERC and stakeholders to investigate what requirements provide little protection to the BES, are unnecessary or redundant. WECC's approach seems much stricter and seems to suggest that if any plausible argument can be made, the requirement cannot be retired. Such an argument is not in line with the rest of the commenters and, therefore, will not be adopted. In addition, as the project proceeds through the standard drafting process, sufficient technical justifications will be put forward for industry review for each proposed requirement for retirement. The industry will have further opportunity to evaluate the technical justifications as the P81 project moves forward.

Comment

SRC believes that the SAR captures the right categories, but states that Criteria B 2 through B 5 could be sub-items of B1. In a similar light, NERC staff states there is significant overlap between Criterion B 3 (Purely Documentation) and Criterion B 5 (Periodic Updates) and these criteria could be combined. Independent Electricity System Operator and SRC also disagree with Criterion B 5.

Response

While annual reviews may be necessary, there may be other ways to ensure periodic reviews are done. Criterion B 5 was contemplated by the P81 SDT more in the context of future phases which would allow for the modification of requirements, not an easily identified retirement. Thus, while to some extent we share the concerns of SRC, NERC staff and Independent Electricity System Operator, we believe that the use of Criterion B 5 may be useful in facilitating review of further requirements by the stakeholders.

Comment

WECC disagrees with the use of Criterion B 2 because data and evidence collection is necessary to demonstrate compliance.

Response

The P81 SDT believes that this concern appears to miss the essential aspect of the P81 project in its initial phase which is to retire requirements that do little to protect BES reliability. Thus, hardwiring in data retention mandatory requirements does not seem aligned with generally accepted methods of auditing or promoting an effective and efficient ERO. It is incumbent on the entities to maintain sufficient evidence to support compliance with requirements, and the P81 SDT believes that any requirements that strictly support compliance assessments without a benefit to reliability should be evaluated for revision or retirement.

Comment

WECC disagrees with Criterion B 7 because it would allow other regulators to enforce a requirement.

Response

The P81 SDT agrees with WECC's overarching concern; however, that situation exists today. If there is a requirement that is already part of a regulatory order or under the purview of another governmental authority and is consistently understood and applied across North America, then the P81 SDT believes it should remain a candidate for retirement to remove this potential for double jeopardy. It is important to note, however, that it must be consistently covered across the whole continent and mandatory so as to ensure no "gaps" exist.

Comment

Independent Electricity System Operator suggests that another word be used other then "Technical" to describe Criterion B.

Response

Based on this concern, the P81 SDT changed "Technical" to "Identifying."

C. <u>Comments of Criterion C</u>

Comment

WECC believes Criterion C 1, C 2, C 4, C 6 and C 7 all need to be made more specific or improved.

Response

The concern seems predicated on Criterion C determining whether or not to retire a requirement, which is not the intent. Instead, these criteria will be used to ensure additional pertinent information and considerations are used to assist in the determination of whether a Reliability Standard requirement satisfies both Criterion A and Criterion B. The P81 SDT shall consider these data and

reference points to make a more informed decision. Also, note that these criteria are conceptual only and were developed to assist the industry and the P81 SDT with their analysis. The P81 SDT thanks WECC for their thorough review; however, it will retain the criteria as written.

Comment

Independent Electricity System Operator states it is confusing as to how the section C, "Additional Data and Reference Points" will be used by the drafting team to determine retirement of Reliability Standards even though they have satisfied Criterion A and Criterion B.

Response

The P81 SDT believes that a review of the technical white paper, which will be issued and will contain the initial list of requirements to be retired, will promote an understanding on how Criterion C was used. Criterion C is only meant to provide additional considerations to provide further justifications that the proposed retirements do not have any other underlying reliability related need.

D. Miscellaneous Comments on Phase I vs. Subsequent Phases

Comment

ACES Power Marketing Standards Collaborators suggest that the scope of the SAR should be changed to include current standards under development.

Response

At this time it appears that including requirements from current standards under development would overly complicate the P81 project and intrude on other standard drafting teams. With that said, the P81 SDT does intend to work with and coordinate with other standard drafting teams to help ensure that new requirements are not being drafted that appear to meet the P81 criteria. Also, the P81 SDT will be working with the Standards Committee to draft guidelines to help standard drafting teams draft requirements that are more results-based, and not requirements that would meet the P81 criteria.

Comment

ERCOT indicates that the criteria used for future phases should remain flexible.

Response

The initial list should not preclude the use of additional criteria for future phases where additional criteria support the elimination of requirements in those efforts. Given the amount of commenters who requested numerous requirements be considered in future phases, it appears reasonable that P81 project should remain flexible to meet the needs of stakeholders. Thus, the P81 SDT has revised the SAR to apply to Phase I only.

Comment

SRC urges the SAR simply suggest that the proposed requirements be considered and evaluated by the SDT as opposed to making a presumption (and hence setting a high expectation for the industry) that the proposed list will be retired.

Response

The P81 SDT did not intend for the list of requirements proposed in the draft SAR to come across as a list without flexibility.

Comment

ACES Power Marketing Standards Collaborators suggests that requirements that are assigned to the wrong functional entities should be added as a criterion for revision or retirement.

Response

The P81 SDT believes that ACES's suggestion should be considered during the development of a Phase 2 SAR. In many instances, applicability can be a complex undertaking and there may be large diversity, irrespective of an entity having some common high-level responsibilities as listed in the NERC Registry and Functional Model.

Comment

NERC staff suggests that any technical justifications that rely on Criterion B 6 should address how NAESB, etc. would handle the requirement.

Response

As a general matter, many commenters suggest that the P81 project develop thorough justifications and remain in line with the suggested Criteria. NERC staff's concern of reliance on Criterion B 6 will also be considered when developing the justifications. The P81 SDT removed references to NAESB, but notes that when relying on B 6, sufficient reference will be made to other mandatory requirements which effectively ensure there will be no gap on a continent-wide basis and in addition, what will ensure that on an ongoing basis, this gap will remain addressed by something other than a NERC standard requirement. The technical white paper will consider these concerns. In addition, the P81 SDT believes that ongoing training for drafting teams will ensure that these types of requirements are no longer developed.

Organization	Yes or No	Question 1 Comment

Organization	Yes or No	Question 1 Comment
Western Electricity Coordinating Council	No	WECC offers the following related to the criteria listed in the SAR.WECC beleives the OVERARCHING CRITERIA listed under "A" needs clarification and that as currently identified is too vague. The Overarching Criterion statement is too broad and is contrary to the FPA Section 215. "Impact" is an ambiguous term. There is no measure as to how to quantify a Requirement's "impact" and to distinguish between "little" impacts as opposed to some other metric of "impact." More importantly, however, a Requirement that has any impact on the reliable operation of the BES cannot be dismissed as inconsequential, even if it is determined to have "little" impact. The "impact" must be weighed against the "burden" of the standard and potential for efforts to demonstrate compliance hindering or preventing other more "impactful" reqiurements. Further, the Standard Requirements work in concert with one another. For many Standard Requirements, it is impossible to reasonably assess the "impact" of a single Standard Requirement. For example, the "purpose" statement for CIP Standard Requirements reads that "[CIP Standard Requirements] should be read as part of a group of standards numbered Standards CIP-002 through CIP-009." To examine the "impact" of a single Standard Requirement, therefore, contradicts the intent and purpose of many Standard Requirements that are crafted to operate in concerns with one another.WECC believes the B1 Administrative Technical Criteria needs claificaiton and is vague as currently written. The term "administrative" is ambiguous and could cover a broad range of activities. Further, "administrative requirements" often require evidence of program or procedure creation. However, WECC does agree with this criteria, but only in the case where all three criteria listed (administrative, does not support reliability, and needlessly burdensome) are met.WECC disagrees witht he B2 Technical Criteria Data Collection/Data Retention. Data Collection/Data Retention is often the only means by which a Responsible Entity can objectively demonstrate compliance. As to mandatory data retention

Organization	Yes or No	Question 1 Comment
		periods, an explicit mandate to retain data may be required to meet compliance obligations unique to a particular Standard Requirement. However, if treated correctly, a requirement for the data collection/retention for compliance purposes could be removed from the Requirmeetns and made part of the Measures or RSAWs.WECC Disagrees with the B3 criteria Purley Documentation unless it can be clearly demonstrated that the dcoumentation does not protect the reliabiltity of the BES in any way. In some cases Plans/Policies/Procedures are necessary for employees to have a guide for not only protection but maintaining and restoring BES assets (i.e. Restoration Plans). Documentation of plans, policies and procedures, is key in defining the parameters of compliance. Further, plans/policies and procedures are often the only means by which Compliance and Enforcement can assess a responsible entity's compliance with a Standard Requirement.WECC Disagrees with the B4 criteria Purely Reporting unless no purpose for the reporting can be identified. Reporting helps overarching organizations (ex. ES ISAC) detect potential issues earlier, by giving them more information and from multiple entities. These issues may seem small or insignificant when viewed by a singular entity but may have a more a drastic impact when viewed from the perspective of the entire BES. WECC Disagrees with the B5 criteria Periodic Updates unless it can be clearly demonstrated that the reproting has no operational benefit to reliability. Without these requirements there is nothing in place to ensure entityies are maintaining, and periodically verifying the accuracy of these documents. With the criteria established as it is, there is no real way of measuring the effect of "operational benefit to reliability". Is it measured by the size of impact (MW), by time (something that will take over a 1hr), or by Time Horizon (Same-Day operations vs. Real Time Operations). It is recommended to establish a more accurate means to measure these criteria. If proberly handled, these reporting requirements that that demonstrate the entities are maintaining certain necessary

Organization	Yes or No	Question 1 Comment
		documents could be moved from the Requirements to the Measures or RSAWs.WECC agrees with the B6 criteria of Business Practices.B7 criteria Redundant: Although WECC agrees requirements should not be redundant with each other, if compliance is left to other regulators (Open Access Transmission Tariff, NAESB, etc.) compliance may not be held up to NERC expectations or interpretations. In identifying redundant standards, only NERC Reliability Standards should be considered.WECC agrees with B* criteria,WECC believes the B9 criteria needs clarification and as written is vague. How will the determination that teh Requirements do little, if anything, to promote the protection of the BES be determined?WECC disagrees with C1. The FFT determination is not predicated on any particular Standard Requirement. The FFT determination is fact specific. Even a requirement that is critical to the BES may have an FFT'd violation if the manner in which the requirement was violated was minor.WECC beleives C2 is vague and needs clarification. Not certan what it means if the requirement is being revieweed in an on-going Standards Development Project. Is this the same as B7 Redundant?WECC agrees C3 is a factor that should be considered.WECC agrees with C4 but beleives information on how the tiers will be viewed should be included.WECC agrees with C5.WECC believes C6 and C7 are vague as written and believes that these last two reference points are intended to indicate that if the answer is yes, then the requirement or standard would NOT be eligable for retirement. This should be clarified.
Independent Electricity System Operator	No	(1) The IESO supports this proposed effort and agrees with most of the criteria, with some exceptions (except #5): "The Reliability Standard requirement requires responsible entities to periodically update (e.g., annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability."Take for example the system restoration plan. An annual review is necessary to ensure that the plan recognizes BES facility changes that occurred since the last review/update. Another

Organization	Yes or No	Question 1 Comment
		example is the exceptions to the cyber security policy that needs to be reviewed and approved by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Applying this criterion in a broad brush manner without looking at each requirement may result in removing requirements that are still needed for reliability.(2) Generally, the nine criteria listed in the SAR are simple and sufficient to be used to determine retirement of reliability standard requirements. It is recommended that the word "Technical" in the heading of the B section "Technical Criteria" be erased as the criteria aren't based on technical data. Also, it is unclear and confusing as to how the section C "Additional Data and Reference Points" will be used by the drafting team to determine retirement of reliability standards even though they have satisfied Criteria A and B. Criterion B.9 can potentially be deleted as its purpose seems to be the duplication of Criterion A.(3) The SAR narrative for TOP-001-1a R3 states the requirement is redundant with IRO-001-1a R8. IRO-001-1a does not exist; we believe, it should be IRO-001-1.1 R8 instead.
NERC Technical Staff Review	No	(1) Revise Criteria A to focus on the content of the Reliability Standards. NERC Staff suggests the following language for Criteria A: "The Reliability Standard requirement requires responsible entities to conduct an activity or task that does little, if anything, to protect reliable operation of the BES." This language is currently included as Criteria B9. NERC notes that both Criterion B8 (hinders the protection or reliable operation of the BES) and B9 (little, if any value as a reliability requirement) are duplicative with Criterion A and should be eliminated. Since any requirement that meets Criterion B8 or B9 would necessarily meet Criterion A, this creates an unintended consequence by undermining the objective that requirements for consideration must satisfy both the overarching Criterion A and a separate technical criteria. For these reasons, NERC Staff supports the elimination of both Criteria B8 and B9 and the re-phrasing of Criteria A. (2) There is significant overlap between Criteria B3 (Purely Documentation) and B5

Organization	Yes or No	Question 1 Comment
		(Periodic Updates) and these criteria could be combined. Criteria B3 addresses requirements for entities to develop a document that is not necessary and Criteria B5 addresses the requirement for entities to periodically update such documentation. NERC Staff suggests renaming Criteria B3 "Documentation" and suggests the following language: "The Reliability Standard requirement requires responsible entities to develop and/or periodically update a document (e.g., plan, policy or procedure) which is not necessary to protect BES reliability." (3) The explanation of Criterion B6 (Commercial or Business Practice) states that the Reliability Standard requirement "is a commercial or business practice, e.g., better served as a NAESB standard or as part of NAESB Electric Industry Registry (EIR)." However, the technical justifications provided for the application of the B6 criteria do not state that the standard/requirement should be addressed in another manner, e.g., with a NAESB standard. Please clarify or otherwise modify this criterion appropriately. Further, the technical justification should address the fact that such business practices may not be applicable to the same entities and may not be mandatory or enforceable.
Northeast Power Coordinating Council	Yes	NPCC participating members support the P81 initiative and agree with the criteria listed in the SAR to identify Reliability Standard requirements for retirement. The criteria are also consistent with FERC's guidance in Paragraph 81 of the FFT Order. With respect to the words in Criterion A wording, it could be interpreted as an indication that the original reliability standard requirement was a mistake. Suggest the SDT consider alternative wording to indicate that the experience with the requirement, over time, has proven not to be useful to accomplish its initially intended reliability objective, or has not produced clear results for the initially intended reliability objective.Criterion A, and Technical Criteria B9 "Little, if any, value as a reliability requirement" are redundant.

Organization	Yes or No	Question 1 Comment
ACES Power Marketing Standards Collaborators	Yes	In general, we agree with the criteria. However, we do offer two suggestions. First, in criterion B.1, we suggest striking "and is needlessly burdensome". If the activity does not support reliability the burden is irrelevant. Second, we suggest if there are current standards under development that are already proposing to retire requirements that those requirements should be considered for inclusion in this project. In order to include those requirements, the proposed reason for retirement should align with one of the criteria in this project. This would accelerate the retirement of unnecessary requirements. Third, we suggest requirements that are assigned to the wrong functional entities should be added as a criterion for revision/retirement.
The Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), the Electric Power Supply Association (EPSA), the Transmission Access Policy Study Group (TAPS), Electricity Consumers Resource Council (ELCON), the American Public Power Association (APPA), the Large Public Power Council (LPPC) and, the Canadian Electricity Association (CEA) (collectively, the Trade Associations).	Yes	The Trade Associations agree with the criteria listed in the SAR to identify Reliability Standard requirements for retirement. As noted above, the criteria were the product of intense discussions among numerous stakeholders, including the Trade Associations, NERC, and the Regional Entities. The criteria are also consistent with FERC's guidance in paragraph 81 of the FFT Order.
SPP Standards Review Group	Yes	We concur that the proposed criteria are a good starting point for the evaluation of requirements to be retired.
Salt River Project	Yes	We like the criteria and methodology.

Organization	Yes or No	Question 1 Comment
SRC	Yes	The criteria listed in the SAR capture the right categories; however, consider restructuring B1. B2 through B5 are examples of administrative requirements and should possibly be sub-items of B1. While we generally support this proposed effort and agrees with most of the criteria, the exception is B5: “The Reliability Standard requirement requires responsible entities to periodically update (e.g., annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.”Take for example the system restoration plan. An annual review is necessary to ensure that the plan recognizes BES facility changes that occurred since the last review/update. Another example is the exceptions to the cyber security policy that needs to be reviewed and approved by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Applying this criterion in a broad brush manner without looking at each requirement may result in removing requirements that are still needed for reliability. In addition, the acid test for retirement of a requirement is when the standard drafting team reviews the overall reliability impact of removing a particular requirement from a standard, and how it may affect other related standards. In brief, it may be a bit premature to pass on this judgment at the SAR stage. We urge the SAR proponent to simply suggest that the proposed requirements be considered and evaluated by the SDT as opposed to making a presumption (and hence setting a high expectation for the industry) that the proposed list will be retired. And, in order to meet the requirements for regulatory approval, we suggest the SDT to provide strong technical basis to justify each retirement.
Manitoba Hydro	Yes	The technical criteria B.9, "Little if any, value as a reliability requirement", is very subjective and should be redefined or clarified.
Georgia System Operations Corporation	Yes	Georgia System Operations agrees with the criteria listed in the SAR to identify Reliability Standard requirements for either modification or

Organization	Yes or No	Question 1 Comment
		withdrawal.
seattle city light	Yes	Seattle City Light supports the consolidated comments of the industry Trade Organizations.
NV Energy	Yes	We agree with the Overarching Criterion and the specific Technical Criteria, and believe that the types of requirements specified in the Technical Criteria can be eliminated without any impact to reliable operation of the interconnected transmission system.
Occidental Energy Ventures Corp.	Yes	Occidental Energy Ventures Corp. ("OEVC") fully supports the efforts taken by the Trades, NERC, and the Regional Entity Management Group to develop the criteria to identify requirements that may be eligible for retirement and modification. The overarching criterion is extremely important in our view, as it serves to remind us all that FERC's original purpose as defined by Section 215(a)(4) of the Federal Power Act is to oversee wide-area reliability of the bulk power system. In recent years, the Commission's authority has expanded into distribution systems and localized load shedding - important issues, but already regulated by the PUCs. In our view, this is duplicative work that increases costs without serving improved reliability.OEVC also believes that the technical criteria are appropriate and complete for now. However, in our view, Item #8 "Hinders the protection or reliable operation of the BES" and Item #9 "Little, if any, value as a reliability requirement" will need further refinement in future phases of this project. Both are quite subjective, and FERC in our opinion will only respond to fact-based quantitative data that shows that BPS reliability is not improved by a given reliability requirement. A painful reminder may be the requirement for secondary Facility Ratings (FAC-008-3) which FERC clearly perceives to be a reliability imperative despite overwhelming industry rejection of the concept. It is unlikely that this view will change unless tangible cost/benefit evidence to the contrary

Organization	Yes or No	Question 1 Comment
		is provided to the Commission.
South Carolina Electric and Gas	Yes	I support removing redundancy and any items that are not related to reliability impacts.
Georgia Transmission Corporation	Yes	Georgia Transmission Corporation agrees with the criteria listed in the SAR to identify Reliability Standard requirements for either modification or withdrawal.
Electric Reliability Council of Texas, Inc.	Yes	ERCOT agrees with the ISO/RTO SRC comments. However, in addition for SRC comments, ERCOT offers the following: ERCOT agrees with the criteria listed in the SAR to identify Reliability Standard requirements for retirement in Phase 1. However, the criteria used for future phases should remain flexible. The initial list should not preclude the use of additional criteria for future phases where additional criteria support the elimination of requirements in those efforts.
SERC EC Planning Standards Subcommittee	Yes	
Southwest Power Pool Regional Entity	Yes	
Bonneville Power Administration	Yes	
Dominion	Yes	
Pepco Holdings Inc & Affiliates	Yes	
PPL Corporation NERC Registered Affiliates	Yes	

Organization	Yes or No	Question 1 Comment
Tampa Electric Company	Yes	
City of Garland	Yes	
Entergy Services, Inc.	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
Central Husdon Gas & Electric Corporation	Yes	
Tucson Electric Power	Yes	
American Electric Power	Yes	
Public Service Enterprise Group	Yes	
CPS Energy	Yes	
Duke Energy	Yes	
Edison Mission Marketing & Trading	Yes	
Illinois Municipal Electric Agency	Yes	
Essential Power, LLC	Yes	
Idaho Power Company	Yes	
Occidental Power Services, Inc.	Yes	

Organization	Yes or No	Question 1 Comment
City of Austin dba Austin Energy	Yes	
Transmission Agency of Northern California	Yes	
Ameren	Yes	
Kansas City Power & Light	Yes	
MidAmerican Energy Company	Yes	

2. The Initial Phase of the P81 project is designed to identify all FERC-approved Reliability Standard requirements that easily satisfy the criteria. Do you agree that the suggested list of Reliability Standard requirements included in the draft SAR easily satisfy the criteria listed in the draft SAR? If you disagree, please provide a statement supporting what Reliability Standard requirements you would add or subtract from the Initial Phase, including a citation to at least one element of Criterion B, as applicable.

Summary Consideration:

A. Support for Initial List

The majority of commenters support the initial list of requirements suggested for retirement in the draft SAR. Supporters include SPP Standards Review Group, The Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), the Electric Power Supply Association (EPSA), the Transmission Access Policy Study Group (TAPS), Electricity Consumers Resource Council (ELCON), the American Public Power Association (APPA), the Large Public Power Council (LPPC), the Canadian Electricity Association (CEA) (collectively, the Trade Associations), Salt River Project, SRC, Georgia System Operations Corporation, Seattle City Light, Duke Energy, NV Energy, Occidental Energy Ventures Corp., South Carolina Electric and Gas, Ameren, Electric Reliability Council of Texas, Inc., SERC EC Planning Standards Subcommittee, Dominion, Pepco Holdings Inc & Affiliates, PPL Corporation NERC Registered Affiliates, Tampa Electric Company, Manitoba Hydro, City of Garland, Entergy Services, Inc., Wolverine Power Supply Cooperative, Inc., Central Hudson Gas & Electric Corporation, Tucson Electric Power, CPS Energy, Edison Mission Marketing & Trading, Illinois Municipal Electric Agency, Idaho Power Company, City of Austin dba Austin Energy, Transmission Agency of Northern California, and Kansas City Power & Light. Also, the following entities appear to generally support the current list, while requesting additional requirements to be added: Georgia Transmission Corporation, Occidental Power Services, Inc., American Electric Power, and ACES Power Marketing Standards Collaborators. This level of support appears to be a testament to the hard work of the collaborative process and provides significant context in which to consider the merits of those stakeholders who requested that certain requirements be added or removed from the initial list.

B. Concerns with requirements included in the initial list

Comment

Northeast Power Coordinating Council (NPCC), Southwest Power Pool Regional Entity (SPP RE), Western Electricity Coordinating Council (WECC), NERC staff technical review (NERC staff) presented concerns with retiring requirements related to PRC-008-0 and PRC-009-0.

Response

As SRC points out, PRC-009-0 is already scheduled to be retired. More specifically, in Order No. 763 at Paragraph 103[3] the Commission accepted the retirement of PRC-009-0 as appropriately replaced with PRC-006-1. Consistent with Order No. 763, PRC-009-0 will become inactive on September 30, 2013 and will be replaced by PRC-006-1. Similarly, under Standards Development Project 2007-17 Protection System Maintenance, which recently passed stakeholders vote on August 27, 2012, PRC-008-0 is scheduled to be retired and replaced with PRC-005-2. PRC-005-2 will likely be presented to the NERC Board of Trustees in November for approval. To avoid confusion and promote regulatory efficiency, the P81 SDT intends to present PRC-008-0 and PRC-009-0 in the final SAR for informational purposes only. Accordingly, PRC-008-0 and PRC-009-0 will not be included in the P81 project for purposes of comment and ballot.

Comment

NPCC is concerned that it may only receive information related to UVLS program assessment and performance after an event if PRC-010-0 R2 and PRC-022-1 R2 are retired.

Response

The P81 SDT believes it is appropriate to retire PRC-010-0 R2 and PRC-022-1 R2 because the Regional Entities' current compliance and monitoring processes provide for the review of UVLS program assessment and performance during a spot check, compliance audit, etc., which makes PRC-010-0 R2 and PRC-022-1 R2 unnecessary. Thus, the P81 SDT believes that PRC-010-0 R2 and PRC-022-1 R2 should remain within the scope of P81 for purposes of comment and ballot.

Comment

WECC and SPP RE requested that CIP-007-3 R7.3 not be retired, based on concerns related to demonstrating compliance with other requirements.

Response

These concerns appear to miss the essential aspect of the P81 project which is to retire requirements that do little to protect BES reliability. The P81 SDT believes that data retention in and of itself has little to do with protecting BES reliability, particularly when the Regions have authority to request data to show compliance with any mandatory Reliability Standard. Thus, hardwiring in data retention into mandatory Reliability Standard requirements does not seem aligned with generally accepted methods of auditing or promoting an effective and efficient ERO compliance program. In other words, it seems to adopt the position of WECC and SPP RE on this matter could essentially be an endorsement that every Reliability Standard requirement should be accompanied with a mandatory data retention requirement, which would seem counterintuitive given the processes set for in the Compliance Monitoring and Enforcement Program. Thus, the P81 SDT believes that CIP-007-3 R7.3 should remain within the scope of P81 for purposes of comment and ballot.

[3] *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, 139 F.E.R.C. ¶ 61,098 (2012).

Comment

WECC also disagrees with the inclusion of IRO-016-1 R2 with a concern that Reliability Coordinators must be required to document their actions for compliance and enforcement purposes.

Response

Reliability Coordinator actions are conducted over recorded lines or via written directives, and, thus, the documentation is already available for a Regional Entity to inspect. Further, during a spot check or compliance audit a Regional Entity has the authority to request information, as well as the entity has the burden to prove compliance – if the entity chooses to prove compliance via recorded phone lines or logs is not necessarily an appropriate subject for a mandatory Reliability Standard. Thus, the P81 SDT believes that IRO-016-1 R2 should remain within the scope of P81 for purposes of comment and ballot.

Comment

WECC and NERC staff express concerns with including MOD-004-1. Specifically, WECC states:

MOD-004 is not redundant to TOP-002 even though the CBM itself may be a tariff issue and rarely used. The reliability piece is that if the CBM is used by a TSP then the details of it must be available for use in system studies. Without the awareness of a transmission holdback for CBM when it exists, a network study could be run and show no issues but if at some time the CBM were implemented an overload could result. This might not always be the case but unless the CBM parameters are known and modeled it could impact reliability.

NERC staff suggests that MOD-004-1 may be more appropriate for a subsequent phase unless a solid technical justification can be developed for MOD-004-1 that addresses relevant FERC's ruling.

Response

One of the tenants of the initial phase of P81 is that the requirement does not need significant technical justifications or editing. Notwithstanding the apparent support for MOD-004-1 to be part of the P81 project, it is also apparent to the P81 SDT that at this time MOD-004-1 needs additional review and consideration prior to any decision to retire all or part of its requirements. It is also noteworthy that there are a large number of requests to consider other MOD standards in subsequent phases, and it is likely appropriate to consider the MOD Standards as a whole so that MOD-004-1 can be more thoroughly analyzed. For example, CBM is referenced in a number of MOD Standards, such as MOD-001-1a, MOD-008-1 and MOD-028-1. Thus, the P81 SDT has removed MOD-004-1 from the list of requirements proposed for the initial phase and MOD-004-1 will be considered in a subsequent phase of the P81 project.

Comment

WECC, Public Service Enterprise Group and Essential Power, LLC state that CIP-002-1a R4 should not be retired. WECC makes several points, including:

"An entity has many enforcement agencies to contact without the FBI listed in the operating instructions they could easily be overlooked. . . . . Retiring R4 will remove the incentive of having a working relationship with the FBI, especially among the smaller entities. Retiring R4 may effectively delay or prevent the FBI from rapidly locating those responsible for sabotage."

Also, Public Service Enterprise Group and Essential Power, LLC state:

"If the entity owns or operates a BES asset, there is a clear reliability benefit to have appropriate law enforcement contacts and procedures to address sabotage or other security incidents. Similarly, the federal agencies feel that this is a good idea. In a coordinated attack environment, sabotage reporting to these Law enforcement agencies from the BES operators and owners would improve the ability of a coordinated response."

Response

The P81 SDT believes that the practices and procedures discussed by WECC, Public Service Enterprise Group and Essential Power, LLC are accomplished via R1 through R3 of CIP-002-1a, not R4. For example, consistent with R2,[4] it is common practice to contact local law enforcement authorities when there is any suspicion that sabotage has occurred at a BES facility. The entity's corporate security and site personnel will consult with local law enforcement to assess the situation and facts to determine whether a suspected or actual act of sabotage has occurred. If they find a suspected or actual act of sabotage has occurred, reliability entities as well as the Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP), as appropriate, will be contacted in accordance with R2. Thus, pursuant to R1 through R3, when there is an instance of sabotage that warrants contacting the FBI or RCMP or any other federal or national governmental authority, entities will contact them. Conversely, the requirement in R4 to establish communication contacts with the FBI or RCMP, as applicable, is purely an administrative, documentation and data collection task requirement – there is no operational or results-based aspect of R4, like there is with R1 through R3. Accordingly, in CIP-001-2a R1 through R3 serve the results-based reliability function, while R4 is a static, administrative requirement that has no direct or clear nexus to protecting BES reliability. For these reasons, the P81 SDT believes that CIP-001-2a R4 should remain within the scope of P81 for purposes of comment and ballot.

Comment

Bonneville Power Administration, WECC and NERC staff do not support the proposed retirement of TOP-001-1a R3.

[4] "**R2.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection."

Response

Bonneville Power Administration, WECC and NERC staff all make valid points. Although there is redundancy between TOP-001-1a R3 and IRO-001-1a R8 related to Reliability Coordinators, this redundancy was addressed in Standards Development Project 2007-03 (Real-time Operations). Specifically, Project 2007-03 eliminated the redundancy in the current version of TOP-001-2 R1 that replaces TOP-001-1a R3 and reads as follows:

Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements.

TOP-001-2 has been approved by the NERC Board of Trustees and will be filed with the Commission for approval; therefore, the P81 SDT intends to present TOP-001-1a R3 in the final SAR for informational purposes only. Accordingly, TOP-001-1a R3 will not be included in the P81 project for purposes of comment and ballot.

Comment

SRC and NERC staff state that VAR-002-WECC-1 R2 and VAR-501-WECC-1 R2 should not be included in the P81 project until they have first been processed for retirement via the WECC regional standards process.

Response

SRC and NERC staff make a valid point that regional standards proposed for retirement need to first proceed through their region prior to being considered for retirement via a NERC standards development project. For these procedural concerns, VAR-002-WECC-1 R2 and VAR-501-WECC-1 R2 have been removed from the P81 project; however, the P81 SDT encourages WECC to consider the deliberations of the collaborative process and act on retiring VAR-002-WECC-1 R2 and VAR-501-WECC-1 R2, as appropriate.

Comment

Central Hudson Gas & Electric Corporation, Public Service Enterprise Group, and American Electric Power and Essential Power, LLC express concern with the inclusion of CIP-003-3 R4 and its sub-requirements in the P81 project. AEP states:

“AEP recommends instead that CIP-003 R1 be removed in which case CIP-003 R3 (and CIP-003 R2.4) can also be removed. However, if the drafting team does not agree with this recommendation, CIP-003 R3 must be retained in order for entities to take targeted exception(s) where applicable (for example, in circumstances where an entity’s program is more stringent than the CIP requirements).”

Public Service Enterprise Group and Essential Power, LLC indicate that “[t]he exceptions language in R3, though rarely used, allows for those instances where an entity is unable to conform with it's cyber security policy.”

Response

The reason for retiring CIP-003-3, -4 R3 and its sub-requirements is directly applicable to the concerns expressed. In other words, although the CIP exception requirements have never been available for use to exempt an entity from compliance with any requirement of any NERC Reliability Standard, entities apparently are reading the CIP exception requirements out of context. These requirements only apply to exceptions to internal corporate policy, and only in cases where the policy exceeds a NERC Reliability Standard requirement or addresses an issue that is not covered in a NERC Reliability Standard. For example, if an internal corporate policy statement requires that all passwords be a minimum of eight characters in length, and be changed every 30 days, this provision could be used for internal governance purposes to lessen the corporate requirement back to the password requirements in CIP-007 R5.3, or in conjunction with a Technical Feasibility Exception (TFE) to something else. Therefore, removal of this requirement has no effect on the TFE process or compliance with any other CIP requirement. Also, the retirement of the CIP exception requirements would not impact an entity's ability to maintain such a process within their corporate policy governance procedures. Consequently, the CIP exception requirements provide little protection for BES reliability and are an internal administrative and documentation requirement that is outside the scope of the other CIP requirements. Thus, the P81 SDT believes that CIP-003-3, -4 R3 and its sub-requirements should remain within the scope of P81 for purposes of comment and ballot.

Comment

Public Service Enterprise Group and Essential Power, LLC also request the P81 project not include EOP-004-1 R1 because it will soon be replaced by EOP-004-2.

Response

The P81 SDT notes that the past ballot of EOP-004-2 did not pass and it is currently in the balloting stage. The P81 SDT has coordinated its efforts with the chair of Project 2009-01 and both agree there is no conflict between retiring EOP-004-1 R1 and the direction of Project 2009-01. At such time that the EOP-004-2 project does obtain stakeholder approval and is scheduled for NERC Board of Trustees review, P81 SDT will reconsider the need to include EOP-004-1 R1. Thus, at this time, the P81 SDT believes that EOP-004-1 R1 should remain within the scope of P81 for purposes of comment and ballot.

Comment

Public Service Enterprise Group and Essential Power, LLC further request that FAC-002-1 R2 be removed from the P81 project based on the concern that the three year study retention requirement could be increased to six years via compliance and monitoring data retention.

Response

The concern of Public Service Enterprise Group and Essential Power, LLC, however, appears to miss the essential aspect of the P81 project in its initial phase which is to retire requirements that do little to protect BES reliability. Thus, hardwiring in data retention

mandatory requirements does not seem aligned with generally accepted methods of auditing or promoting an effective and efficient ERO compliance program. Accordingly, the P81 SDT believes that FAC-002-1 R2 should remain within the scope of P81 for purposes of comment and ballot.

Comment

NERC staff questioned the inclusion of FAC-008-1 R2, FAC-008-1 R3, FAC-008-3 R4, FAC-008-3 R5 and FAC-013-2 R3 in the P81 project. Specifically, NERC staff states:

"These requirements, combined with others, provide checks and balances on the Facility Rating Methodology and Transfer Capability methodology established by the responsible entities. This provides a reliability benefit by requiring the responsible entity to consider areas in which their methodology may not be sufficient to support reliable operation of the interconnected transmission system. There may be better ways of assuring that entities have sufficient methodologies and alternatives should be considered during Phase II. NERC Staff suggests that the SDT reconsider whether discussing the methodology (and not the numerical rating of a facility) has commercial or market related implications. With respect to FAC-013-2 R3, NERC Staff suggests that the SDT reconsider whether the requirement relates to "a back and forward on transfer capability" as noted in the draft SAR, as the requirement pertains only to the methodology for determining transfer capability."

Response

The P81 SDT notes that Page 5 of NERC's Standards Process Manual states:

"A Reliability Standard includes a set of Requirements that define specific obligations of owners, operators, and users of the North American Bulk Power Systems. The Requirements shall be material to reliability and measurable."

It appears difficult to read into the plain language of FAC-008-1 R2, FAC-008-1 R3, FAC-008-3 R4, FAC-008-3 R5 and FAC-013-2 R3 specific obligations that are material to reliability and measurable or provide more than a little amount of protection to BES reliability. For instance, in practice, while the owners of ratings and transmission capability methodologies have made these documents available for comment during the duration of the mandatory Reliability Standard regime, experience shows that little, if any, technical comments have not been submitted on these documents. In the regional processes, entities are on a variety of committees and have professional relationships, and, therefore, if they have a concern with a methodology, they have ample opportunity to seek out professional technical critique as a best practice. FAC-008-1 R2, FAC-008-1 R3, FAC-008-3 R4, FAC-008-3 R5 and FAC-013-2 R3 seem toonly formalize a vehicle for professional technical critique without an exacting nexus between it and reliability. Given that entities that develop these methodologies must comply with rigorous requirements in FAC-008 and FAC-013, the P81 SDT believes that the addition of a mandatory best practice technical critique process does not seem necessary, material or measurable. It is also noteworthy that there is no obligation for any entity to request a methodology nor is there any obligation on the owner of the methodology to respond to any

comments with any level or burden of technical thoroughness. Thus, the P81 SDT believes that FAC-008-1 R2, FAC-008-1 R3, FAC-008-3 R4, FAC-008-3 R5 and FAC-013-2 R3 should remain within the scope of P81 for purposes of comment and ballot.

C. Suggested additions to the initial list

Comment

NPCC suggests adding FAC-003-1 R3, FAC-003-1 R4, CIP-005-3 R4, and CIP-007-3 R8.

Response

While the P81 SDT believes there appears to be merit in considering the FAC-003 and CIP requirements suggested by NPCC, these requirements were discussed in the collaborative process and it was generally agreed that these requirements need additional technical review prior to any consideration of retirement. Thus, these requirements will be considered in a subsequent phase of the P81 project.

Comment

NPCC and SRC suggest adding IRO-014-2 R2 and it sub-requirements. According to NPCC, these requirements are administrative requirements only and do not enhance reliability, while SRC states that these requirements satisfy Criterion B1 and Criterion B5.

Response

While IRO-014-2 R2 seems like a valid candidate for P81, it is not a FERC-approved Reliability Standard. At this time, it has been adopted by the NERC Board of Trustees and has yet to be filed with FERC for approval. As the P81 project matures or a more formalized approach to P81 is adopted by NERC in its Rules of Procedures or processes, the consideration of Reliability Standards not yet approved may be practical. However, at this time, the scope of the P81 project remains FERC-approved Reliability Standards. The exception to this is if a FERC-approved requirement being proposed for retirement is duplicated in a standard that has only been adopted by the NERC Board of Trustees. Thus, at this time, IRO-014-2 R2 is not ripe for consideration in P81.

Comment

ACES Power Marketing Standards Collaborators suggests adding FAC-010-2.1 R5 and FAC-011-2 R5 in the initial phase for the following reasons:

"FAC-010-2.1 R5 is an administrative requirement for the Planning Authority to respond to comments on its SOL methodology. Failure to provide a written response to technical comments does not impact reliability. The PC is already required to distribute its methodology in R4. Any functional entity that would have provided technical comments will see any adjustments. This requirement meets Criteria B.1 and B.9.(7) FAC-011-2 R5 is an administrative requirement for the Reliability Coordinator to respond to comments on its SOL methodology. Failure to provide a written response to technical comments does not impact reliability. The RC is already required to distribute its methodology in R4."

Response

ACES Power Marketing Standards Collaborators' position is similar to the reasons that FAC-008-1 R2, FAC-008-1 R3, FAC-008-3 R4, FAC-008-3 R5 and FAC-013-2 R3 were included in the draft SAR as satisfying the criteria and appropriate for retirement. Further, the language in all of these Reliability Standard requirements is very similar. Thus, the P81 SDT has added FAC-010-2.1 R5 and FAC-011-2 R5 to the initial phase of P81.

Comment

ACES Power Marketing Standards Collaborators suggests that IRO-005-3 R11 is redundant with MOD-028-1 R6.1, MOD-029-1a R3, and MOD-030-2 R2.4 and that the MOD standards already require the Transmission Service Provider to consider IROLs and SOLs when determining Available Transfer Capability/Available Flowgate Capability and Total Transfer Capability. Specifically, IRO-005-3 R11 reads:

"The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes."

Response

It appears that while IRO-005-3 R11 may be redundant for the reasons stated by ACES Power Marketing Standards Collaborators; however, this requirement has been retired in IRO-005-4, which was approved by the Board of Trustees and is pending a filing at FERC. Thus, recognizing that that Project 2006-06 Reliability Coordination has already received many of the necessary approvals to retire IRO-005-3 R11, it does not seem to serve regulatory efficiency to include IRO-005-3 R11 in the P81 project as well. Thus, the P81 SDT did not add IRO-005-3 R11 to the initial phase of P81.

Comment

ACES Power Marketing Standards Collaborators suggests COM-001-1.1 should be retired because English is the dominant language used.

Response

To retire such a requirement would possibly need coordination with the Canadian authorities in French speaking provinces and those in areas of the United States were Spanish is a first language. Such coordination would seem to complicate the retirement of COM-001-1.1, and, thus, the P81 SDT believes it is more appropriately considered in a subsequent phase.

Comment

With regard to VAR-001-2 R5, ACES Power Marketing Standards Collaborators states that it:

". . . is redundant with FERC's pro forma tariff and was originally included in the NERC policies to align them with said tariff. The requirement compels the PSE and LSE to arrange for reactive resources to satisfy the reactive requirements of the Transmission Service

Provider. PSEs and LSEs cannot purchase transmission service without purchasing reactive service or demonstrating to the transmission provider that they have arranged for reactive resources. From a practical perspective, this means they always purchase reactive service from the Transmission Provider. Furthermore, it is the Transmission Operator that actually ensures reactive resources are dispatched per VAR-001-2 R2."

Response

The P81 SDT notes that when approving VAR-001, in Order No. 693 at Paragraph 1858,[5] the Commission recognized:

". . . that all transmission customers of public utilities are required to purchase Ancillary Service No. 2 under the OATT or self-supply, but the OATT does not require them to provide information to transmission operators needed to accurately study reactive power needs. The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities."

ACES Power Marketing Standards Collaborators states VAR-001-2 R5 appears to be redundant with Ancillary Service No. 2 under the OATT. Moreover, VAR-001-2 R5 is very limited to this OATT obligation and regional process, and, therefore, does not speak to the Commission's concern related to providing information to Transmission Operators for accurate reactive power studies. Therefore, it appears that VAR-001-2 R5 satisfies the P81 criteria by doing little to protect BES reliability and being redundant with the OATT. Thus, the P81 SDT has added VAR-001-2 R5 to the initial phase of P81.

Comment

ACES Power Marketing Standards Collaborators also suggests adding BAL-002 R1, BAL-002 R3, BAL-005-0.1b R1 and its sub-requirements, INT-004-2 R1, and TOP-005-2a R3.

Response

The P81 SDT notes that during the collaborative process the linkage between the BAL and INT standards was discussed and there seems to be merit considering whether some BAL and INT standards could be combined. The Trade Associations, among others, suggested this be conducted in a subsequent phase of P81. Given the complexity related to the linkage between the BAL and INT standards, along with TOP-005-2a R3, the P81 SDT believes that additional review should be conducted in a subsequent phase of P81 prior to retiring the suggested BAL and INT standards.

Comment

[5] VAR-001-2 was approved via a Letter Order issued on January 10, 2011.

ACES Power Marketing Standards Collaborators also suggests including PRC-011-0 R2, PRC-015-0 R3, PRC-016-0.1 R3, PRC-017-0.1 R2, PRC-021-0.1 R2, PRC-023-1 R2, and PRC-023-2 R3. American Electric Power suggests the following additions: PRC-021-1 R2; PRC-018-1 R5; PRC-016-0.1 R3; PRC-015-0 R3; PRC-011-0 R2; PRC-007-0 R3; CIP-006 R1.5; CIP-004-3 R4; CIP-007 R5.1.1; CIP-007 R5.1.3; CIP-007 R6.3; CIP-007 R6.4; CIP-003-3, CIP-003-4 R1; CIP-003-3, CIP-003-4 R1.2; CIP-003-3, CIP-003-4 R1.3; CIP-003-3, CIP-003-4 R2.4; CIP-003-3, CIP-003-4 R3. Tampa Electric recommends that the P81 SDT ensure that the CIP requirements proposed for removal via P81 are also removed from v5 of the NERC CIP standards. Tampa Electric also supports the consideration of the following for NERC CIP standards: (1) Removal of data collection requirements (CIP-005-3a,-4a R5.3, CIP-006-3c,-4c R7 and R8.3, CIP-007-3,-4 R5.1.2, R6.4and R7.3, CIP-008-3,-4 R2); and (2) Removal of annual review requirements (CIP-002-3,-4 R4, CIP-003-3,-4 R1.3, R4.3, R5.1.2, and R5.3, CIP-006-3c,-4c R1.8, CIP-007-3,-4 R9, and CIP-009-3,-4 R1).

Response

There was much discussion around the PRC and CIP standards during the collaborative process. There are several issues that impact the retirement of these requirements including not creating a reporting gap by retiring PRC standards and the coordination of CIP standards with the Version 5 SDT. Given these complications, the P81 SDT believes it is best to consider these CIP and PRC Standards as part of a subsequent phase of the P81 project. To address Tampa Electric's other concern, the P81 SDT has been coordinating its activities with the CIP Version 5 SDT, and will continue to do so, so that the agreed upon retirements do not reemerge in CIP Version 5.

Comment

Occidental Power Services, Inc. requests the removal of the PSE function from the applicable sections of the following: INT-001-3 R1, INT-004-2 R2, IRO-001-1.1 R3, IRO-001-1.1 R8, IRO-005-3 R10, TOP-005-2 R3, and VAR-001 R5. ACES Power Marketing Standards Collaborators also suggests removing PSE and LSE the applicable sections of IRO-005-3 R10.

Response

The removal of applicable from the requirements is an interesting suggestion that would take some more technical review and modification of the requirements. Thus, the P81 SDT believes this suggestion is more appropriate for consideration in a subsequent phase of P81.

Comment

Georgia Transmission Corporation suggests the following additions: MOD-016-1.1 R1, MOD-016-1.1 R1.1, MOD-016-1.1 R3, MOD-017-0.1 R1, MOD-017-0.1 R1.1, MOD-017-0.1 R1.2, MOD-017-0.1 R1.3, MOD-017-0.1 R1.4, MOD-018-0 R1, MOD-018-0 R1.2, MOD-018-0 R1.3, MOD-018-0 R2, MOD-019-0.1 R1, MOD-020-0 R1, MOD-021-1 R1, MOD-021-1 R2, MOD-021-1 R3, PRC-005-1b R2, PRC-005-1b R2.1, PRC-005-1b R2.2, PRC-006-1 R7, PRC-006-1 R8, PRC-006-1 R14, PRC-007-0 R2, PRC-007-0 R3, PRC-011-0 R2, PRC-015-0 R3, PRC-017-0 R2, PRC-018-1 R5, PRC-021-1 R2, PRC-023-1 R3.3, and TOP-001-1a R4.

Response

Georgia Transmission Corporation points out many of the same requirements that the trade associations suggest for subsequent phases of the P81 project. As mentioned above, for example, we are deferring the consideration of MOD-004-1 to a subsequent phase so it may be considered in the context of other MOD Standards. The P81 SDT believes it is more appropriate to consider Georgia Transmission Corporation's suggestions in a subsequent phase.

Comment

South Carolina Electric and Gas asked if the measures associated with requirements being proposed for retirement would be modified or removed as well.

Response

The relevant measures and other associated elements will be marked as retired in the standard. These will be identified in the redlines of the standards that will be posted with the requirements during the next comment period.

Comment

ERCOT states that the justification statement for BAL-005-0.1b R2 could benefit from additional clarification regarding how it is redundant with BAL-001 R1 and R2 and the justification for EOP-009-2 R2 should also be enhanced.

Response

The P81 SDT notes that additional clarification for BAL-005-0.1b R2, EOP-009-0 R2 and other requirements will be included in the technical white paper being developed by the P81 SDT.

In summary, of the initial list in the draft SAR, MOD-004-1, VAR-002-WECC-1 R2 and VAR-501-WECC-1 R2 have been deferred to a subsequent phase. Of the suggested additions, it appears that only VAR-001-2 R5, FAC-010-2.1 R5 and FAC-011-2 R5 satisfy the P81 criteria without significant technical review, and, thus, are appropriate to be added to the final SAR for the initial phase. As a general note, any requirements suggested for the initial phase, but not adopted, shall be considered by the P81 SDT in a subsequent phase of the project, and, therefore, the entities do not need to resubmit the requirements.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	From page 25 of the SAR, "Since PRC-008-0 R1; PRC-008-0 R2; PRC-009-0 R1; PRC-009-0 R1.1; PRC-009-0 R1.2; PRC-009-0 R1.3; PRC-009-0 R1.4; PRC-009-0 R2; PRC-010-0 R2; PRC-022-1 R2 provides little protection to the BES and better handled under event analysis and lessons learned papers, it should be removed." is not valid due to that fact that as of this posting the Event Analysis Program (EAP) has not become part of the RoP and is therefore a voluntary program. The requirements that are covered by these standards are mandatory cannot be replaced by a voluntary program. Refer to the following:Additionally, the EAP process is an after-the-fact Analysis of an event or events. These standard requirements (PRC-008-0 R1; PRC-008-0 R2; PRC-009-0 R1; PRC-009-0 R1.1; PRC-009-0 R1.2; PRC-009-0 R1.3; PRC-009-0 R1.4; PRC-009-0 R2; PRC-010-0 R2; PRC-022-1 R2) address different needs which can be determined only if such an event occurs. For example, from PRC-008-0--"R1. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance." This requirement addresses the need to have an equipment maintenance and testing program in place prior to an event. Discovering that an entity did not have this as a result of an event analysis would, in this case, be after the damage is done and would not serve reliability. Analyzing why the UFSL program did not operate properly would come under the purview of the EAP but that is different from the Standard's intent. PRC-008-0--"R2. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days)." If the EAP was relied upon to meet this requirement the receipt or confirmation of this program would only occur after an event. PRC-009-0--"R1. The Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall

Organization	Yes or No	Question 2 Comment
		analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:R1.1 A description of the event including initiating conditions.R1.2 A review of the UFLS set points and tripping times.R1.3 A simulation of the event.R1.4 A summary of the findings."Although this Standard appears that it could be covered under EAP, it is a highly detailed technical study and needs to be carried out on its own accord. Event Analysis will focus primarily what caused the event that triggered the UFLS program but not necessarily the program itself. Because of the importance of the UFLS program to the reliability of the system, its performance should not be analyzed only on a voluntary basis and not only by those entities that actually shed load as a result of the event, but against the whole regional program.PRC-009-0--"R2. The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event."This is administrative, refer to the response for R1 preceding. PRC-010-0--"R2. The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days)." This should not triggered only after an event, see preceding response for R1 preceding. PRC-022-1--"R2. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90 calendar days of a request."This is the same situation as for the UFLS program. Refer to the responses preceding. IRO-014-2 --The following requirements in Standard IRO-014-2 are administrative requirements only and do not enhance reliability, and should be considered for removal in the Initial

Organization	Yes or No	Question 2 Comment
		Phase. "R2. Each Reliability Coordinator shall maintain its Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 as follows: [Violation Risk Factor: Lower] [Time Horizon: Same Day Operations and Operations Planning]2.1. Review and update annually with no more that 15 months between reviews. 2.2. Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update.2.3. Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update."FAC-003-1 Requirements R3, and R4 (shown below) and their sub-requirements are administrative (reporting) requirements only and do not enhance reliability, and should be considered for removal in the Initial Phase. R3. The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.In addition, as shown below, CIP-005-3 R4 and CIP-007-3 R8 are essentially the same. Suggest to eliminate CIP-005-3 R4 and include assessment of access points in CIP-007-3 R8.CIP-005-3 R4:"R4. Cyber Vulnerability Assessment - The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following: R4.1. A document identifying the vulnerability assessment process; R4.2. A review to verify that only ports and services required for operations at these access points are enabled; R4.3. The discovery of all access points to the Electronic Security Perimeter; R4.4. A review of controls for default accounts, passwords, and network management community strings; R4.5. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan." CIP-007-3 R8:"R8. Cyber Vulnerability Assessment - The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the

Organization	Yes or No	Question 2 Comment
		following: R8.1 A document identifying the vulnerability assessment process; R8.2 A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled; R8.3 A review of controls for default accounts; and, R8.4 Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan."
Southwest Power Pool Regional Entity	No	SPP RE does not agree that PRC-008 R1 and R2 should be retired or that they provide "little protection to the BES and [are] better handled under event analysis and lessons learned papers". UFLS equipment maintenance and testing programs ARE important to BES reliability, in a preventative mode, and are NOT covered under the Event Analysis process. Preventative maintenance is very important to reliability; without it, events are more likely. Industry should not wait for an event to happen to collect information and consider maintenance and testing. UFLS is the last line of "defense in depth protection of the BES" (Criteria C6). SPP RE's comment follows the discussion around removing PRC-005 and its relationship to BES reliability.SPP RE does not agree that CIP-007-3 R7.3 should be retired. R7.3 requires the Responsible Entity to maintain records of how data storage media was erased or destroyed prior to disposal or redeployment of the Cyber Asset (which could be simply the media previously removed from the Cyber Asset). In the absence of such records, the Responsible Entity cannot demonstrate compliance with CIP-007-3 R7.1 and CIP-007-3 R7.2, rendering those requirements not auditable. Elimination of this requirement could also result in a loss of visibility of Cyber Assets that have been disposed of or redeployed, also hampering the ability of the Responsible Entity to demonstrate compliance and the Compliance Enforcement Authority to audit compliance with the remaining requirements.
Bonneville Power Administration	No	BPA does not support the proposed retirement of TOP-001-1a R3. BPA does not agree that TOP-001-1a R3 is redundant with IRO-001-1a R8 because IRO-001-1a R8 only addresses RC directives, whereas TOP-001-1a R3 addresses both RC directives and TOP directives. BPA believes that retiring TOP-001-1a R3 before TOP-001-2 R1 is

Organization	Yes or No	Question 2 Comment
		effective would create a gap because no requirement would address TOP directives. BPA supports the additional proposed retirements and thanks the drafting team for their efforts.
ACES Power Marketing Standards Collaborators	No	(1) We believe there are other requirements that easily meet the criteria. (2) VAR-001-2 R5 is redundant with FERC's pro forma tariff and was originally included in the NERC policies to align them with said tariff. The requirement compels the PSE and LSE to arrange for reactive resources to satisfy the reactive requirements of the Transmission Service Provider. PSEs and LSEs cannot purchase transmission service without purchasing reactive service or demonstrating to the transmission provider that they have arranged for reactive resources. From a practical perspective, this means they always purchase reactive service from the Transmission Provider. Furthermore, it is the Transmission Operator that actually ensures reactive resources are dispatched per VAR-001-2 R2. Thus, VAR-001-2 R5 satisfies criteria B.1, B.6, B.7, and B.9.(3) BAL-002 R1 and R3 are redundant. R1 compels the BA to have access to and operate Contingency Reserve to respond to disturbances. R3 requires the BA to activate sufficient Contingency Reserve to comply with DCS. We suggest removing R1 because it is redundant (Criterion B.7). This applies to both versions 0 and 1 of the standard.(4) BAL-005-0.1b R1 and its sub-requirements are not necessary. All generation, transmission and load is currently contained within the metered boundaries of a BA. It is impossible to add new generation, transmission and load and not be within the metered boundaries of a BA. To do so, would require the equipment owner to carve out an area from the BA. For example, if a TO added a new transmission line, it would have to put a meter on both ends to carve it out of any BA footprint. In the process, they, in effect, create a new BA. The only way these requirements can't be met would be if BAs started removing metering equipment en masse. Given removing metering equipment has significant financial consequences due to inaccurate energy accounting; it is not going to happen. Thus, it meets Criterion B.9. Furthermore, TOs are already required to identify metering requirements in FAC-001-0 R2.1.6 as part of its facility connection requirements. It also meets Criterion B.7.(5) COM-001-1.1 is unnecessary and the audit of it has

Organization	Yes or No	Question 2 Comment
		largely become a demonstration that it is an administrative requirement. English is the primary language across the vast majority of the Interconnections under NERC's purview and it is the primary language in all of the areas under FERC's jurisdiction. For the few companies in areas where English is not predominant, those companies will be unable to meet other requirements if they use a different language to speak with companies from predominantly speaking English languages. Furthermore, audits have regulated this to predominantly an administrative requirement. The auditors largely look for statement that the English language is required despite the fact that all evidence has been provided in English, observations of control center conversations have shown English is used, and the audit has been conducted in English. If there is a need for this requirement, it should be relegated to a regional requirement for those regions that include areas that do not speak predominantly English. Thus, this requirement meets Criteria B.1 and B.9.(6) FAC-010-2.1 R5 is an administrative requirement for the Planning Authority to respond to comments on its SOL methodology. Failure to provide a written response to technical comments does not impact reliability. The PC is already required to distribute its methodology in R4. Any functional entity that would have provided technical comments will see any adjustments. This requirement meets Criteria B.1 and B.9.(7) FAC-011-2 R5 is an administrative requirement for the Reliability Coordinator to respond to comments on its SOL methodology. Failure to provide a written response to technical comments does not impact reliability. The RC is already required to distribute its methodology in R4. Any functional entity that would have provided technical comments will see any adjustments when they receive the methodology. This requirement meets criteria B.1 and B.9.(8) INT-004-2 R1 has nothing to do with reliability and should be included in the list of retirements. Failing to reload an Interchange Transaction that was curtailed for a reliability event has no reliability impact. It is a remnant from the NERC Policies that was added at the request of market participants because once transactions were cut, reliability entities did not always allow the transaction to resume once the reliability issue had been addressed. This is strictly a commercial issue. Thus, this requirement meets Criterion B.9.(9)

Organization	Yes or No	Question 2 Comment
		IRO-005-3 R10 should be modified to reflect the functional model. In cases where there are differences in derived limits, PSEs and LSE cannot operate to the most limiting parameters. They are not in a position to even have information on the parameters such as facility ratings. Rather, their role is to follow directives. Thus, inclusion of PSE and LSE in the requirement does not support reliability. Thus, this requirement meets Criterion B.9. (10) IRO-005-3 R11 is redundant with MOD-028-1 R6.1, MOD-029-1a R3, and MOD-030-2 R2.4. The MOD standards already require the TSP to consider IROLs and SOLs when determining Available Transfer Capability/Available Flowgate Capability and Total Transfer Capability. This requirement meets Criterion B.7. (11) PRC-011-0 R2 should be retired. A requirement is not needed to compel the TO and DP to provide data on its UVLS equipment maintenance program to the Regional Entity. The Regional Entity's CMEP and NERC's Rules of Procedure compel the TO and DP to provide information regarding enforceable requirements per the Regional Entity's request. This requirement meets Criteria B.1, B.4, and B.9.(12) PRC-015-0 R3 should be retired. A requirement is not needed to compel the TO, GO and DP to provide data on their Special Protection Systems (SPS) to the Regional Entity. The Regional Entity's CMEP and NERC's Rules of Procedure compel the TO, GO and DP to provide information regarding enforceable requirements per the Regional Entity's request. This requirement meets Criteria B.1, B.4, and B.9.(13) PRC-016-0.1 R3 should be retired. A requirement is not needed to compel the TO, GO and DP to provide data on their SPS Misoperations analyses and corrective action plans to the Regional Entity. The Regional Entity's CMEP and NERC's Rules of Procedure compel the TO, GO and DP to provide information regarding enforceable requirements per the Regional Entity's request. This requirement meets Criteria B.1, B.4, and B.9.(14) PRC-017-0.1 R2 should be retired. A requirement is not needed to compel the TO, GO and DP to provide documentation of the SPS maintenance and testing program to the Regional Entity. The Regional Entities CMEP and NERC's Rules of Procedure compel the TO, GO and DP to provide information regarding enforceable requirements per the Regional Entity's request. This requirement meets Criteria B.1, B.4, and B.9.(15) PRC-

Organization	Yes or No	Question 2 Comment
		021-0.1 R2 should be retired. A requirement is not needed to compel the TO and DP to provide UVLS program data to the Regional Entity. The Regional Entities CMEP and NERC's Rules of Procedure compel the TO and DP to provide information regarding enforceable requirements per the Regional Entity's request. This requirement meets Criteria B.1, B.4, and B.9.(16) PRC-023-1 R2 and PRC-023-2 R3 are redundant with FAC-008-1 R1.2.1 and FAC-008-3 Part 2.4.1. FAC-008-1 R1.2.1 and FAC-008-3 Part 2.4.1 already require the GO and TO to consider relay protective devices when determining facility ratings. The DP cannot limit the Facility Rating because a DP does not have Transmission Facilities. They only have relays that impact Facility Ratings that must ultimately be considered by the TO. This requirement meets Criterion B.7(17) TOP-005-2a R3 is redundant with the INT standards and should be retired. In the NERC Functional Model, the only role for the PSE is to facilitate Arranged Interchange. The INT standards already govern Arranged Interchange and contain the necessary information that the PSE must provide. Furthermore, Project 2007-03 Real-Time Operations has proposed retirement of this requirement as it is redundant with NAESB e-Tag specifications. Beyond the E-tag data there is no additional information that a PSE or LSE could provide for the BA or TOP to conduct operational assessments. This requirement meets Criteria B.6, B.7 and B.9.(18) PRC-006-1 R7 should be retired. Failure by a Planning Coordinator to provide data to another Planning Coordinator within 30 days is not a reliability issue because Planning Assessments have long time lines to complete the studies. Furthermore, any failure to provide data within 30 calendar days is most likely a simple oversight. If a Planning Coordinator refuses to provide data, the requesting Planning Coordinator may get involved and which will compel them to provide the data. This can be done without the need for this requirement. This requirement meets criterion B.4.
Western Electricity Coordinating Council	No	WECC supports the majority of the Standards Requirements identified, but notes concerns with the following. WECC recommends eliminating CIP-003 R1 in its entirety.WECC disagrees with the inclustion of CIP-007, R7.3. This requirement is necessary for entity's to demonstrate compliance with the other sub-requirements of CIP 007 R7. However, this requirement could be moved to a Measure or RSAW to

Organization	Yes or No	Question 2 Comment
		demonstrate compliance with the other sub-requirements of CIP-007, R7.WECC disagrees with the includsion of IRO-016-1, R2. Required documentation of the RC's actions to remedy an event is necessary for quality and efficient root cause analysis, including insight into the RC's wide view of actions during an event or disagreement. The language in the SAR statement for IRO-016-1 R2 points to this information being monitored through Spot Checks or other compliance monitoring methods. If this standard is removed yet the information is to be included in future compliance monitoring there must be some sort of methodology that requires the entity to retain the associated data to be kept for the duration of the required cycle for monitoring (i.e. audit cycle if monitored through audits). It is important that entities document the actions taken that analyze the effect on the system as well as the BES for either an even or/and for the disagreement on the problem. Therefore, it is important that this information is part of the overall compliance monitoring program.MOD-004 is not redundant to TOP-002 even though the CBM itself may be a tariff issue and rarely used. The reliability piece is that if the CBM is used by a TSP then the details of it must be available for use in system studies. Without the awareness of a transmission holdback for CBM when it exists, a network study could be run and show no issues but if at some time the CBM were implemented an overload could result. This might not always be the case but unless the CBM parameters are known and modeled it could impact reliability.WECC disagrees with the recommendations with PRC-008-0 R1 and PRC-008-0 R2. Unless these standards are being superseded, WECC does not agree that they provide "little protection to the BES." They are not administrative in nature like the other standards in this group. They insure that maintenance and testing program is established and implemented for an entity's UFLS protection systems. Without these standards, there is reduced assurance that UFLS protection systems will operate correctly when called upon for an under-frequency event. UFLS has a vital role in its effectiveness for preserving system stability and elimination of these standards may reduce its effectiveness. This standard is about making sure the equipment is maintained not about collecting data. If and when PRC-005-2 is adopted, and if it were to include the UFLS devices, then this standard should be

Organization	Yes or No	Question 2 Comment
		considered for removal.WECC believes the statements associated with TOP-001-1a, R3 are incorrect. Removing TOP-001-1a would result in no NERC requirement for parties to follow TOP directives. The current TOP-001-1a R3 requires BOTH TOP and RC directives to be followed. The proposed IRO-001-3 R2 requires ONLY RC directives to be followed. In addition, the SAR statement is incorrect. TOP-001-1a R3 applies to directives issued by the TOP (and also the RC). IRO-001-1a applies only to directives from the RC. If the intent, as they state, is to replace TOP-001-1a R3 with IRO-001-3, that leaves a void for an entity to comply with a directive from the TOP. Only the part about following an RC directive is redundant. Requirement should be modified to eliminate the redundancy, but not retired. WECC disagrees witht he inclusion of CIP-001, R4. An entity has many enforcement agencies to contact without the FBI listed in the operating instructions they could easily be overlooked. This Requirement has encouraged entities to establish a current communication line with the FBI. In fact, several other larger entities are members of InfraGardÂ®, which is a partnership between the FBI and the private sector. Retiring R4 will remove the incentive of having a working relationship with the FBI, especially among the smaller entities. Retiring R4 may effectively delay or prevent the FBI from rapidly locating those responsible for sabotage. The requirement is not “needlessly burdensome”, which is a criteria for deletion.WECC believes the requirements VAR-002-WECC-1, R2, and VAR-502-WECC-1, R2, are probably the best way of demonstrating compliance with the accociated R1 requirments. The two VAR R2 requirements do not say the entity has to submit the information to WECC (Regional Entity), only that it shall have the documentation to prove exclusion for the sub requirements in R1. We’ve had cases where entities don’t meet the 98% availability and if the entity was claiming exclusion time, WECC would want to review the documentation that proves the exclusion. It is in the entity’s best interest to keep exclusion documentation in case its units don’t make the 98%, but this is beter suited for a Measure or RSAW.
Independent Electricity System Operator	No	(1) We generally agree that most of the identified standards/requirements would meet the proposed criteria. However, as indicated under Q1, we believe that the “annual review” criterion is too broad which could result in retiring some

Organization	Yes or No	Question 2 Comment
		requirements that are still needed for reliability. In addition, the acid test for retirement a requirement is when the standard drafting team reviews the overall reliability impact of removing a particular requirement from a standard, and how it may affect other related standards. In brief, it is premature to pass on this judgment at the SAR stage. We urge the SAR proponent to simply suggest that the proposed requirements be considered and evaluated by the SDT as opposed to making a presumption (and hence setting a high expectation for the industry) that the proposed list will be retired. And, in order to meet the requirements for regulatory approval, we suggest the SDT to provide strong technical basis to justify each retirement.
American Electric Power	No	AEP does not disagree with a majority of the requirements proposed by the drafting team, though we recommend the team reconsider the inclusion of CIP-003 R3 and associated sub-requirements. AEP recommends instead that CIP-003 R1 be removed in which case CIP-003 R3 (and CIP-003 R2.4) can also be removed. However, if the drafting team does not agree with this recommendation, CIP-003 R3 must be retained in order for entities to take targeted exception(s) where applicable (for example, in circumstances where an entity's program is more stringent than the CIP requirements).AEP would like the team to consider the following additional Reliability Standard requirements as candidates for retirement on this initial, or subsequent, request for comment. Standard: PRC-021-1Requirement: R2Requirement Text: Each Transmission Operator and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.Criterion: B4,9Standard: PRC-018-1Requirement: R5Requirement Text: The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.Criterion: B2Standard: PRC-016-0.1Requirement: R3Requirement Text: The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).Criterion: B4Standard: PRC-015-0Requirement:

Organization	Yes or No	Question 2 Comment
		R3Requirement Text: The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).Criterion: B4Standard: PRC-011-0Requirement: R2Requirement Text: The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days).Criterion: B4Standard: PRC-007-0Requirement: R3Requirement Text: The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).Criterion: B4Standard: CIP-006Requirement: R1.5Requirement Text: Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-3 Requirement R4.Criterion: B7Standard: CIP-007Requirement: R5.1.1Requirement Text: The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-3 Requirement R5.Criterion: B7Standard: CIP-007Requirement: R5.1.3Requirement Text: The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-3 Requirement R5 and Standard CIP-004-3 Requirement R4.Criterion: B7Standard: CIP-007Requirement: R6.3Requirement Text: The Responsible Entity shall maintain logs of system events related to cyber security, where technically Feasible, to support incident response as required in Standard CIP-008-3.Criterion: B7Standard: CIP-007Requirement: R6.4Requirement Text: The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.Criterion: B1, B3Standard: CIP-003-3, CIP-003-4Requirement: R1Requirement Text: Cyber Security Policy - The Responsible Entity shall document and implement a cyber security policy that represents

Organization	Yes or No	Question 2 Comment
		management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:Criterion: B1, B3, B7, B9Standard: CIP-003-3, CIP-003-4Requirement: R1.2Requirement Text: The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets. Criterion: B1, B3, B7, B9Standard: CIP-003-3, CIP-003-4Requirement: R1.3Requirement Text: Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2. Criterion: B5Standard: CIP-003-3, CIP-003-4Requirement: R2.4Requirement Text: The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy. Criterion: B7Comment: Although AEP does not necessarily agree with removal of this requirement (see R3 comment below), R2.4 is redundant with R3.3 (which is being removed) and should probably be removed along with R3.Standard: CIP-003-3, CIP-003-4Requirement: R3 (R3.1, R3.2, R3.3)Requirement Text: Exceptions - Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s). Criterion: Comment: If R1 is not removed, R3 (or some exception process) is necessary. For example, if the Cyber Security Policy goes above and beyond the standards, then an exception may be needed even though the standards are met.
Public Service Enterprise Group	No	For these requirements, KEEP:CIP-001-2a R4. If the entity owns or operates a BES asset, there is a clear reliability benefit to have appropriate law enforcement contacts and procedures to address sabotage or other security incidents. Similarly, the federal agencies feel that this is a good idea. In a coordinated attack environment, sabotage reporting to these Law enforcement agencies from the BES operators and owners would improve the ability of a coordinated response. Thus we feel that this requirement should be kept within the standards.CIP-003-3 R3. The exceptions language in R3, though rarely used, allows for those instances where an entity is unable to conform with it's cyber security policy. In addition, the requirement has been approved by the industry and FERC more than once. It's removal may have a negative impact on the industry. CIP-003-4 R3. The exceptions language in R3, though

Organization	Yes or No	Question 2 Comment
		rarely used, allows for those instances where an entity is unable to conform with it's cyber security policy. In addition, the requirement has been approved by the industry and FERC more than once. It's removal may have a negative impact on the industry. TOP-005-2a R1. "TOP-003-2 requires operating entities such as GOs and TOs to provide operating data to BAs ands TOPs. In TOP-005-2a, R2 and R3 requires BAs and TOPs to exchange this data with other BAs and TOPs . R1 requires BA and TOP recipients of such data to execute a confidentiality agreement so that its confidentiality is protected. This requirement ultimately protects the confidentiality of data provided by entities under TOP-003-2.For these requirements, KEEP BUT MODIFY:FAC-002-1 R2. We believe the three year limitation on documentation sets a limit; otherwise six years may be required (the period between audits. We do suggest removing the language " and shall provide the documentation to the Regional Reliability Organization(s) and NERC on request (within 30 calendar days)." because we see no reliability benefit.For these rerquirements, KEEP UNTIL REPLACED:EOP-004-1 R1. NERC's Event Analysis Process was approved by NERC's BOT on February 9, 2012. This process has already been adopted as RFC's process under EOP-004-1, R1. Draft standard EOP-004-2 will replace Regional reporting requirements in R1 with consistent NERC-wide requirements; however, while the draft does not presently require the use of the NERC Event Analysis Process, that process is embedded in proposed NERC ROP changes filed with FERC on May 7, 2012. Keep until these NERC ROP changes are approved by FERC and become effective.PRC-008-0 R1. This is required for reliability. Such a testing program has been incorporated into draft PRC-005-2 When this is adopted, PRC-008-0 can be retired.PRC-009-0 R1. The NERC Event Analysis Process is embedded in proposed NERC ROP changes filed with FERC on May 7, 2012. Keep until these NERC ROP changes are approved by FERC and become effective.PRC-009-0 R1.1. See R1 above.PRC-009-0 R1.2. See R1 above.PRC-009-0 R1.3. See R1 above.PRC-009-0 R1.4. See R1 above.
Essential Power, LLC	No	CIP-001-2a, R4. This requirement should be removed from the Paragraph 81 project. If an entity owns or operates a BES asset, there is a clear reliability benefit to have

Organization	Yes or No	Question 2 Comment
		appropriate law enforcement contacts and procedures to address sabotage or other security incidents. Similarly, the federal agencies feel that this is a good idea. In a coordinated attack environment, sabotage reporting to these law enforcement agencies from the BES operators and owners would improve the ability of a coordinated response. Thus we feel that this requirement should be kept within the standards.CIP-003-3, R3. This requirement should be removed from the Paragraph 81 project. The exceptions language in R3, though rarely used, allows for those instances where an entity is unable to conform to its cyber security policy. In addition, the requirement has been approved by the industry and FERC more than once. Its removal may have a negative impact on the industry.CIP-003-4, R3. This requirement should be removed from the Paragraph 81 project. The exceptions language in R3, though rarely used, allows for those instances where an entity is unable to conform to its cyber security policy. In addition, the requirement has been approved by the industry and FERC more than once. Its removal may have a negative impact on the industry.EOP-004-1, R1. This requirement should be removed from Phase 1 of the Paragraph 81 project, until replaced by EOP-004-2. NERC's Event Analysis Process was approved by NERC's BOT on February 9, 2012. This process has already been adopted as RFC's process under EOP-004-1, R1. Draft standard EOP-004-2 will replace Regional reporting requirements in R1 with consistent NERC-wide requirements; however, while the draft does not presently require the use of the NERC Event Analysis Process, which is embedded in proposed NERC ROP changes filed with FERC on May 7, 2012. This requirement should be kept until these NERC ROP changes are approved by FERC.FAC-002-1, R2. This requirement should be removed from the Paragraph 81 project, and modified instead. We believe the three year limitation on documentation sets a limit; otherwise six years may be required (the period between audits). We do suggest removing the language “and shall provide the documentation to the Regional Reliability Organization(s) and NERC on request (within 30 calendar days)." because we see no reliability benefit to this element of the requirement.
Occidental Power Services,	No	OPSI recommends the following additions for Phase 1 implementation: 1. INT-001-3, R1. The Load Serving, Purchasing-Selling Entity shall ensure that Arranged

Organization	Yes or No	Question 2 Comment
Inc.		Interchange is submitted to the Interchange Authority for all Dynamic Schedules at the expected average MW profile for each hour.Criteria: B6, B9Statement: This requirement is at best a business practice of markets (protocol). These schedules can be rejected if not correctly submitted, can be cut if not executed correctly, and the PSE can be penalized if there are offenses.Recommendation: Remove PSE from R1 and from the Applicability section.2. INT-004-2, R2. The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occurs:o R2.1 The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than Â±10%o R2.2 The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than Â±25 megawatt-hourso R2.3 A Reliability coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons. Criteria: B6,B9Statement: This requirement is at best a business practice of markets (protocol). These schedules can be rejected if not correctly submitted, can be cut if not executed correctly, and the PSE can be penalized if there are offenses.Recommendation: Remove PSE from R2 and from the Applicability section.3. IRO-001-1.1, R3 and R8.R3. The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing- Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.R8. Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the

Organization	Yes or No	Question 2 Comment
		Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.Criteria: B9Statement: PSEs do not generally receive Reliability Directives from RCsRecommendation: Remove PSE from R3 and R8 and from the Applicability section.4. IRO-005-3, R10. In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.Criteria: B9Statement: PSEs do not generally derive limits for the transmission of power over the BES.Recommendation: Remove PSE from R10 and from the Applicability section.5. TOP-005-2, R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.Criteria: B6,B9Statement: PSEs have to supply this information as a requirement for participating in market functions.Recommendation: Remove PSE from R3 and from the Applicability section.6. VAR-001, R5. Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.Criteria: B6,B9Statement: This is a requirement to participate in competitive markets (generally, it is included in the transmission rate) or is required by tariffs in non-competitive markets. The PSE has no option but to purchase the reactive power in order to make the transaction.Recommendation: Remove PSE from R5 and from the Applicability section.
Georgia Transmission Corporation	No	GTC agrees that the suggested list easily satisfies the criteria in the draft SAR, but GTC also believes this is an incomplete list for Phase I. GTC also believes the following Reliability Standard requirements easily satisfy the criteria listed in the draft SAR and recommends reconsidering and adding to the list in the initial Phase I.MOD-016-1.1;R1:The Planning Authority and Regional Reliability Organization shall have

Organization	Yes or No	Question 2 Comment
		documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses. [Meets Criteria A, B1, B2, B3, B9]MOD-016-1.1 R1.1 The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005, TPL-006, MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, and MOD-021. The data submittal requirements shall stipulate that each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values. Meets Criteria A, B1, B3, B4, B9MOD-016-1.1 R3 The Planning Authority shall distribute its documentation required in R1 for reporting customer data and any changes to that documentation, to its Transmission Planners and Load-Serving Entities that work within its Planning Authority Area. Meets Criteria A, B1, B3, B9MOD-016-1.1 R3.1 The Planning Authority shall make this distribution within 30 calendar days of approval. Meets Criteria A, B1, B3, B9MOD-017-0.1 R1 The Load-Serving Entity, Planning Authority and Resource Planner shall each provide the following information annually on an aggregated Regional, subregional, Power Pool, individual system, or Load-Serving Entity basis to NERC, the Regional Reliability Organizations, and any other entities specified by the documentation in Standard MOD-016-1_R1. Meets Criteria A, B1, B4, B9MOD-017-0.1 R1.1 Integrated hourly demands in megawatts (MW) for the prior year. Meets Criteria A, B1, B4, B9MOD-017-0.1 R1.2 Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year. Meets Criteria A, B1, B4, B9MOD-017-0.1 R1.3 Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years. Meets Criteria A, B1, B4, B9MOD-017-0.1 R1.4 Annual Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for at least five years and up to ten years into the future, as requested. Meets Criteria A, B1, B4, B9MOD-018-0 R1 The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner's report of actual and forecast demand data (reported on either an aggregated or

Organization	Yes or No	Question 2 Comment
		dispersed basis) shall: Meets Criteria A, B1, B3, B9MOD-018-0 R1.1 Indicate whether the demand data of nonmember entities within an area or Regional Reliability Organization are included, and Meets Criteria A, B1, B3, B9MOD-018-0 R1.2 Address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and Net Energy for Load. Meets Criteria A, B1, B3, B9MOD-018-0 R1.3 Items (MOD-018-0_R 1.1) and (MOD-018-0_R 1.2) shall be addressed as described in the reporting procedures developed for Standard MOD-016-1_R 1. Meets Criteria A, B1, B3, B9MOD-018-0 R2. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each report data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner on request (within 30 calendar days). Meets Criteria A, B1, B4, B9MOD-019-0.1 R1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-1_R 1. Meets Criteria A, B1, B4, B9MOD-020-0 R1. The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make known its amount of interruptible demands and Direct Control Load Management (DCLM) to Transmission Operators, Balancing Authorities, and Reliability Coordinators on request within 30 calendar days. Meets Criteria A, B1, B4, B9MOD-021-1 R1. The Load-Serving Entity, Transmission Planner and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed. Meets Criteria A, B1, B3, B9MOD-021-1 R2. The Load-Serving Entity, Transmission Planner and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy

Organization	Yes or No	Question 2 Comment
		for Load in the data reporting procedures of Standard MOD-016-0_R1. Meets Criteria A, B1, B3, B9MOD-021-1 R3. The Load-Serving Entity, Transmission Planner and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on request (within 30 calendar days). Meets Criteria A, B1, B3, B9PRC-005-1b R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include: Meets Criteria A, B1, B3, B9PRC-005-1b R2.1. Evidence Protection System devices were maintained and tested within the defined intervals. Meets Criteria A, B1, B3, B9PRC-005-1b R2.2. Date each Protection System device was last tested/maintained. Meets Criteria A, B1, B3, B9PRC-006-1 R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. Meets Criteria A, B1, B4, B9PRC-006-1 R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. Meets Criteria A, B1, B4, B9PRC-006-1 R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following:14.1. UFLS program, including a schedule for implementation 14.2. UFLS design assessment 14.3. Format and schedule of UFLS data submittal Meets Criteria A, B1, B3, B9PRC-007-0 R2. The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a

Organization	Yes or No	Question 2 Comment
		UFLSprogram database. Meets Criteria A, B1, B4, B9PRC-007-0 R3. The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days). Meets Criteria A, B1, B3, B4, B9PRC-011-0 R2. The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days). Meets Criteria A, B1, B3, B4, B9PRC-015-0 R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days). Meets Criteria A, B1, B4, B9PRC-017-0 R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days). Meets Criteria A, B1, B3, B4, B9PRC-018-1 R5. The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years. Meets Criteria A, B1, B2, B3, B9PRC-021-1 R2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request. Meets Criteria A, B1, B4, B9PRC-023-1 R3.3. The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list. Meets Criteria A, B1, B4, B9TOP-001-1a R4. Each Distribution Provider and Load-Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory

Organization	Yes or No	Question 2 Comment
		requirements. Under these circumstances, the Distribution Provider or Load-Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions. Same requirement as R3 which made the Phase I list, only difference is applicability.
NERC Staff Technical Review	No	After further review, NERC Staff recommends that the SDT review the following standard requirements and consider moving them from Phase I to Phase II. If the SDT determines the following standard requirements still fall into Phase I, a more robust technical justification would be needed.(1) FAC-008-1 R2, R3, FAC-008-3 R4, R5 and FAC-013-2 R3: These requirements, combined with others, provide checks and balances on the Facility Rating Methodology and Transfer Capability methodology established by the responsible entities. This provides a reliability benefit by requiring the responsible entity to consider areas in which their methodology may not be sufficient to support reliable operation of the interconnected transmission system. There may be better ways of assuring that entities have sufficient methodologies and alternatives should be considered during Phase II. NERC Staff suggests that the SDT reconsider whether discussing the methodology (and not the numerical rating of a facility) has commercial or market related implications. With respect to FAC-013-2 R3, NERC Staff suggests that the SDT reconsider whether the requirement relates to "a back and forward on transfer capability" as noted in the draft SAR, as the requirement pertains only to the methodology for determining transfer capability.(2) PRC-008-0 R2: Maintenance and testing of underfrequency load shedding (UFLS) relays is necessary to assure reliable operation of a UFLS program and this requirement is included in PRC-005-2 as part of Project 2007-17, Protection System Maintenance and Testing. NERC Staff recommends that the language in R2 relating to implementing its UFLS equipment maintenance and testing program remain to avoid a reliability gap prior to the effective date of PRC-005-2. NERC Staff recognizes that the second part of R2 does meet the criteria in the SAR and recommends that the SDT consider revising the requirement in a future phase to remove the language that requires an entity to "provide UFLS maintenance and testing program results to

Organization	Yes or No	Question 2 Comment
		its Regional Reliability Organization and NERC on request (within 30 calendar days)." (3) TOP-001-1a R3: The technical justification states that this requirement is redundant with IRO-001-1a R8. NERC Staff notes that the requirement is only partially redundant until IRO-001-3 is approved by FERC and therefore, it is premature to consider it for Phase I; it should be considered for Phase II.(4) MOD-004-1: NERC Staff notes that there are a number of Commission directives associated with MOD-004-1 and the technical justification provided for the elimination of this standard should directly address these directives. If a solid technical justification cannot be made, NERC Staff suggests that the requirements should not be included in Phase I. In addition to the above, NERC Staff recommends that the SDT consider removing the following standard requirements from the scope of the P81 project:(1) PRC-008-0 R1: The requirement to have a maintenance and testing program for UFLS is necessary to assure reliable operation of a UFLS program and this requirement is included in PRC-005-2 as part of Project 2007-17, Protection System Maintenance and Testing. NERC Staff recommends retaining R1 to avoid a reliability gap prior to the effective date of PRC-005-2.(2) PRC-009-0 R1: Analysis to assess the performance of UFLS equipment and program effectiveness following system events provides a reliability benefit by identifying whether the UFLS program is effective and whether modifications are necessary. A requirement similar to R1 is included in FERC-approved standard PRC-006-1 and NERC Staff recommends retaining R1 to avoid a reliability gap prior to the effective date of PRC-006-1. If the SDT believes this requirement is not necessary, the justification for removing R1 should discuss Commission comments in Order No. 763 pertaining to Requirement R11 in PRC-006-1.(3) VAR-002-WECC-1 and VAR-501-WECC-1: NERC Staff notes that the regional standards should be removed from the scope of the P81 project because they must first be eliminated via the regional standards development process prior to being processed through the NERC standard development process.
MidAmerican Energy Company	No	FERC Order 706 clearly states that an exception forms alternative obligations for the responsible entity to meet the requirements; an exception is not an exemption from the requirements. We believe a Responsible Entity should still be allowed to have

Organization	Yes or No	Question 2 Comment
		exceptions to its cyber security policy. MidAmerican Energy Company agrees with the proposed removal of CIP-003-3 (CIP-003-4) R3, R3.1, R3.2, R3.3, as long as CIP-003-3 (CIP-003-4) R2.4 remains and allows for possible exceptions to a Responsible Entities' cyber security policy. R2.4 states "The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy." When removing requirements eligible for TFEs, revisions to the Rules of Procedure Appendix 4D - Procedures for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standards will be necessary. For example, CIP-005-3, R2.6 should be deleted from the list of requirements with TFEs in the Scope section on page 1 if the requirement is removed as part of this process.
SPP Standards Review Group	Yes	From our review of the list we feel that this is again, a good starting point, but would hope that the drafting team could add or subtract requirements as needed as Phase 1 of the project develops.
The Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), the Electric Power Supply Association (EPSA), the Transmission Access Policy Study Group (TAPS), Electricity Consumers Resource Council (ELCON), the American Public Power Association (APPA), the Large Public Power Council (LPPC) and, the Canadian Electricity Association (CEA) (collectively, the Trade Associations).	Yes	The Trade Associations agree with the suggested list of Reliability Standard requirements contained in the SAR for the Initial Phase of P81.

Organization	Yes or No	Question 2 Comment
Salt River Project	Yes	Yes
SRC	Yes	o PRC-009-0 R1 - R2 are in the process of being retired by PRC-006-1 as such these requirements will eventually go away. o VAR-002-WECC-1 R2 - Regional standards/requirements for retirement should go through the regional standards process not the NERC continent wide process. o VAR-501-WECC-1 R2 - Regional standards/requirements for retirement should go through the regional standards process not the NERC continent wide process. o Consider adding IRO-014-2 R2 requirements: R2 Each Reliability Coordinator shall maintain its Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 as follows: [Violation Risk Factor: Lower] [Time Horizon: Same Day Operations and Operations Planning]2.1. Review and update annually with no more that 15 months between reviews. 2.2. Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update.These meet criteria B1 and B5.
Georgia System Operations Corporation	Yes	Georgia System Operations agrees with the suggested list of Reliability Standard requirements contained in the SAR for the Initial Phase of P81.
seattle city light	Yes	Seattle City Light supports the consolidated comments of the industry Trade Organizations.
Duke Energy	Yes	The initial phase of the P81 project should contain only requirements that can quickly gain industry and regulatory support and that there is adequate time to prepare a strong technical justification for. Duke Energy asks the P81 Standards Drafting Team to ensure these parameters are taken into consideration as the list is finalized, and move to a subsequent phase any requirements that could take additional time to develop a strong technical justification and consensus for.

Organization	Yes or No	Question 2 Comment
NV Energy	Yes	Our review of the rationale for each of the suggested requirements of the draft SAR supports the conclusion that these requirements should be subject to retirement.
Occidental Energy Ventures Corp.	Yes	OEVC believes that the phased approach proposed in the SAR is prudent and likely the most effective. Only the most obvious candidates for retirement or modification should be presented at this early date. If the industry moves too-far, too-fast, the result may be a blanket rejection of every proposal. Once FERC is comfortable that the industry is in-tune to their sense of risk - which includes public perception of their oversight effectiveness - we believe they will be prepared to deal with requirements that seem important on the surface, but whose contribution to reliability is illusory.
South Carolina Electric and Gas	Yes	Will the measures associated with requirements that are up for retirement be modified or removed?Eg. Removing R2 of a standard but not removing the text in M1 which refers to R2 of that same standard.
Ameren	Yes	We appreciate the excellent work done by the P81 Project team in developing the criteria and agree with the list of suggested standards/requirements that easily satisfy the criteria in this initial phase.
Electric Reliability Council of Texas, Inc.	Yes	ERCOT agrees with the ISO/RTO SCR comments. However, in addition to the SRC comments, ERCOT offers the following:ERCOT agrees that all the requirements included in the SAR warrant retirement based on the relevant criteria, as supported by the corresponding justification statements. ERCOT offers the following additional comments related to the justification statements for the SDT's consideration:BAL-005-0.1b R2 - The justification statement could benefit from additional clarification regarding the reason why this requirement is redundant, because it isn't readily apparent why this is redundant with BAL-001 R1 and R2. Maintaining CPS requires the use of regulation. Therefore, it is implicit that the relevant functional entities have regulation to comply with BAL-001 R1 and 2. Also, the justification should clarify the point of the discussion related to equating compliance based on

Organization	Yes or No	Question 2 Comment
		compliance of BAL-001 R 1 and 2 and how that argument justifies retirement. CIP-001-2a R4 - The justification statement should clarify that this requirement is redundant to the communications obligations in R1-3.CIP-003-3, 4 R1.2 - In addition to the justifications presented in the SAR, the term "readily available" is ambiguous and creates the opportunity for the use of CEA subjective judgment during compliance assessments. This is problematic for compliance risk generally, but is especially problematic when the requirement is administrative in nature. Entities should not be subject to unnecessary compliance risk based on ambiguity that can result in subjective compliance determinations based on the opinion of CEA personnel, as opposed to the four corners of the requirements, especially when the underlying requirement provides no reliability value. Further evidence that this requirement serves no purpose is the fact that it is not included in CIP v5. CIP-003-3 R3, 3.1, 3.2 and 3.3 - In addition to the justifications presented in the SAR, this issue is already fully addressed in the TFE process in Appendix 4D of the ROP, which is not only adequate, but is the appropriate place for this type of administrative function related to documentation. There are a specific set of defined requirements that allow an exception, and those exceptions have be to be filed according to the TFE process. Thus, the requirements proposed for retirement are redundant to that process. CIP-003-3, -4 R4.2 - In addition to the justification presented in the SAR, the phrase "based on sensitivity", is ambiguous and creates the opportunity to insert subjective judgment into compliance assessments. This is problematic for compliance risk generally, but especially when the requirement is administrative in nature AND redundant. Entities should not be subject to unnecessary compliance risk based on ambiguity resulting in subjective compliance determinations, as opposed to the four corners of the requirements, especially when the underlying requirement provides no operational reliability value. Further evidence that this requirement serves no purpose is the fact that it is not included in CIP v5. CIP-005-3a, -4a R2.6 - The justification statement could benefit from additional clarification as to why the banner is not useful. An appropriate use banner has not been useful over time, because people who intend to use sites inappropriately will simply ignore the

Organization	Yes or No	Question 2 Comment
		banner. Banners are generally considered to be a legal protection and not a security protection. Further evidence that this requirement serves no purpose is the fact that it has been removed from CIP v5 because the use of banners does not meet a reliability objective.CIP-007-3, -4 R7.3 - In addition to the justification presented in the SAR, it should be noted that to demonstrate that an entity performed the data destruction under R7.1 and R7.2, the entity needs to collect evidence. Having a separate requirement for evidence is redundant and not needed. COM-001-1.1 R6 - In addition to the justification presented in the SAR, the justification statement could note that this policy should be documented in the ROP for information within NERCNet that is considered sensitive or impacting to the BES. It should be a voluntary best practice or business practice for other information so that entities may use it, or use some other policy that better fits its circumstances. The justification should state that the NERCNet policy should be a voluntary best practice type of issue for information that is not considered sensitive or impacting to the BES. EOP-009-0 R2 - This is a reporting obligation and a documentation issue. The justification statement should also note that both documentation and reporting on this does not rise to the level of a reliability standard. The statement could note that this may be a best practices issue, but just for documentation. Reporting test results to REs isn't a best practice. Additionally, the justification should not state that the relevant information is better considered / obtained during an audit. If it's not relevant to the mandatory requirements, then it has no place in CMEP proceedings.FAC-002-1 R2 - The justification should not include that the relevant information is better considered / obtained during an audit. If it's not relevant to the mandatory requirements, then it has no place in CMEP proceedings.FAC-008-1 R1.3.5 - In addition to the justification presented in the SAR, the justification statement could note that the term "other assumptions" is ambiguous and introduces the potential for inefficient/ineffective administration of the CMEP due to introduction of subjectivity and opinions into compliance assessments. This is problematic for compliance risk generally, but especially when the requirement is administrative in nature AND redundant. Entities should not be subject to unnecessary compliance risk based on ambiguity resulting in

Organization	Yes or No	Question 2 Comment
		subjective compliance determinations, as opposed to the four corners of the requirements, especially when the underlying requirement provides no operational reliability value.FAC-008-1 R2; FAC-008-1 R3; FAC-008-3 R4; FAC-008-3 R5 - In addition to the justification presented in the SAR, the justification statement could note that it is inappropriate for entities other than the owners of equipment to establish facility ratings. The owners don't have to change their ratings, but the scheme is far more effective if the respective functional roles are distinct and not blurred by the review process contemplated in the requirements proposed for retirement. The owners should set the ratings and the RCs receive them and perform their functions in accordance with those ratings. The RC should not be involved with the TO/GO business-management of their equipment. Also, by keeping the roles distinct, it mitigates any liability risk of the third party if the owner uses its input and then the equipment breaks because of the new rating;FAC-013-2 R3 - Same comment as above.MOD-004-1 R1; MOD-004-1 R1.1; MOD-004-1 R1.2; MOD-004-1 R1.3; MOD-004-1 R2; MOD-004-1 R3; MOD-004-1 R3.1; MOD-004-1 R3.2; MOD-004-1 R4; MOD-004-1 R4.1; MOD-004-1 R4.2; MOD-004-1 R5; MOD-004-1 R5.1; MOD-004-1 R5.2; MOD-004-1 R6; MOD-004-1 R6.1; MOD-004-1 R6.2; MOD-004-1 R7; MOD-004-1 R8; MOD-004-1 R9; MOD-004-1 R9.1; MOD-004-1 R9.2; MOD-004-1 R10; MOD-004-1 R11; MOD-004-1 R12; MOD-004-1 R12.1; MOD-004-1 R12.2; MOD-004-1 R12.3 - ERCOT agrees with the comments/justifications.PRC-008-0 R1; PRC-008-0 R2; PRC-009-0 R1; PRC-009-0 R1.1; PRC-009-0 R1.2; PRC-009-0 R1.3; PRC-009-0 R1.4; PRC-009-0 R2; PRC-010-0 R2; PRC-022-1 R2 - In addition to the justification presented in the SAR, the justification statement could note that the tasks required in these standards are administrative/documentation/reporting in nature and they don't affect reliability from a standards perspective. These could either be best practices or evidentiary in RSAWs - e.g. provide UFLS/UVLS program documentation - which could be relative to requirements that have actionable UVLS/UFLS requirements;TOP-001-1a R3 - ERCOT agrees with the justification with regard to the RC function, but the TOP standard also requires BAs/GOPs to follow the directives of the TOP, so the two relevant requirements are not apples to apples. Modification to one or the other

Organization	Yes or No	Question 2 Comment
		may be needed to ensure appropriate authority and corresponding obligation to follow that authority is reflected in one or the other standard, or both, but eliminate overlaps.TOP-005-2a R1 - ERCOT agrees with the justification. This should either be in the ROP or just via the ISN access process/agreement.VAR-002-WECC-1 R2; VAR-501-WECC-1 R2 - ERCOT agrees with the justification, but if the documentation/reporting are not relevant for the requirement, then the SAR should not suggest the REs should seek the info in CMEP proceedings, which should solely focus on compliance with the substance of the standards.
SERC EC Planning Standards Subcommittee	Yes	
Dominion	Yes	
Pepco Holdings Inc & Affiliates	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
Tampa Electric Company	Yes	
Manitoba Hydro	Yes	
City of Garland	Yes	
Entergy Services, Inc.	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
Central Husdon Gas & Electric	Yes	

Organization	Yes or No	Question 2 Comment
Corporation		
Tucson Electric Power	Yes	
CPS Energy	Yes	
Edison Mission Marketing & Trading	Yes	
Illinois Municipal Electric Agency	Yes	
Idaho Power Company	Yes	
City of Austin dba Austin Energy	Yes	
Transmission Agency of Northern California	Yes	
Kansas City Power & Light	Yes	

3. The subsequent phases of the P81 project are designed to identify all FERC-approved Reliability Standard requirements that could not be included in the Initial Phase due to the need for additional analysis or an editing of language. Please list any Reliability Standard requirements that you believe should be revised or retired in a subsequent phase, and include a brief supporting statement and citation to at least one element of Criterion B for each requirement listed.

Summary Consideration:

The P81 SDT is very appreciative of the time and effort the commenters spent developing their responses to Question 3. The commenters proposed numerous requirements for consideration in a subsequent phase, including requirements in BAL, CIP, INT, FAC, MOD, and PRC Reliability Standards, among others. As a general observation, the commenters suggested several ways to handle Reliability Standard requirements in the subsequent phases, including (i) retiring a requirement; (ii) modifying the requirement; (iii) changing the functional applicability of a requirement; and (iv) combining requirements or standards. Also, several commenters, such as ERCOT, Independent Electricity System Operator and SPP Standards Review Group requested the ability to raise additional Reliability Standard requirements during the subsequent phases. Given the level of interest in the subsequent phases of the P81 project, it is appropriate for the P81 SDT to carefully consider how best to propose a process for the subsequent phases. To some extent, ERCOT said it well:

"The SDT should establish a prospective process that provides adequate time and opportunity for entities to perform a meaningful review of remaining requirements to determine which additional requirements warrant retirement and to develop appropriate criteria, if relevant, that may be incremental to the ones proposed in this SAR, and to develop appropriate retirement justifications based on the relevant retirement criteria."

Consequently, while all the requests for consideration of Reliability Standard requirements in subsequent phases will receive consideration (including those requirements suggested for Phase I, but deferred to a subsequent phase), the process by which that consideration will be undertaken needs to be developed in light of the requirements suggested for subsequent phases. Accordingly, based on the comments, the P81 SDT intends to develop and suggest options to the Standards Committee in the near future on how to move forward with the subsequent phases.

Organization	Yes or No	Question 3 Comment
ACES Power Marketing		(1) EOP-002-3 R6 and R7 and their sub-requirements are redundant with BAL-001-

Organization	Yes or No	Question 3 Comment
Standards Collaborators		0.1a R1 and R2 and BAL-002 R4. BAL-001-0.1a R1 compels a BA to meet CPS1. BAL-001-0.1a R2 compels a BA to meet CPS2. BAL-002 R4 compels a BA to respond meet the DCS for all reportable events less than MSSC. EOP-002-3 R6 and R7 do not make the BA any more or less responsible to meet these requirements but rather creates an opportunity for double jeopardy. Furthermore, EOP-002-3 R6 and R7 do not make any sense in context with the CPS1 and CPS2 calculations. They are averages over a long term and would never require the emergency actions listed in the sub-requirements to comply with them. These requirements have already proven to incent behavior that is contrary to reliability (criterion B.8). At the August NERC BOT meeting, the NERC OC Chair explained that a BA shed load to meet the DCS criterion even though there were no other concerns (i.e. voltage, frequency, IROL or SOL violations) on the transmission system at the time. These requirements meet criterion B.7. (2) EOP-004-1 R2 should be considered for future retirement. The approval of the Event Analysis Procedure obviates the need for a standard requirement to analyze Bulk Electric System disturbances. This would be especially true if the procedure is added to the Rules of Procedure as NERC has planned. This requirement meets criterion B.7.(3) Retirement of FAC-001-0 R3 should be considered in the next phase. There is an implied obligation for the TO to update its Facility connection requirements when they change. Additionally, a requirement to make them available to the Regional Entity and users of the transmission system is unnecessary. First, the Regional Entity could request them through the compliance monitoring process. Second, the TO will provide the Facility connection requirements to those with genuine interconnection requests because the TO will want its connection standards met. This requirement meets criterion B.4, B.7 and B.9. (4) FAC-002-1 R1 should be revised to reflect the NERC Functional Model because it assigns the requirements to the wrong functional entities. The Transmission Planner and Planning Coordinator are responsible for conducting the assessments for new Facilities. The requirement appears to be an attempt to require the GO, TO, DP, and LSE to coordinate with the TP and PC. However, the requirement actually defines what is required in the TP and PC assessments which unfortunately place these

Organization	Yes or No	Question 3 Comment
		responsibilities on the GO, TO, DP and LSE. None of these functional entities have the capability to meet requirements such as performing dynamics studies. This requirement meets criterion B.8. (5) VAR-001-2 R2 and TOP-006-2 R2 are duplicate requirements. VAR-001-2 R2 compels the TOP to acquire sufficient reactive resources. TOP-006-2 R2 requires the RC, TOP and BA to monitor reactive resources. Since VAR-001-2 R2 applies all the time, a TOP cannot know they have acquired and maintained reactive resources unless they are monitoring them. Furthermore, TOP-006-2 R2 incorrectly applies to the BA. According to the NERC Functional Model, the BA cannot monitor reactive resources that are not generators and have no role in ensuring system voltages. Thus, TOP-006-2 R2 meets criterion B.7 because it is redundant, and it meets criteria B.8 and B.9 because it assigns responsibility to a functional entity (BA) that cannot meet it. This distracts the BA from its reliability mission.
Independent Electricity System Operator		(1) IRO-004-2 R1 could be retired if the wording in IRO-001-1.1 R8 was changed to cover all operating timeframes (Criterion B7). (2) We do not have any other particular standards/requirements in mind at this time. However, we will review and propose additional candidates for future phases as this project gets into the mid or end of Phase I. We believe the industry should focus on the Phase I effort at this time to gauge the regulator's and industry's reaction before marching too far down the path.
Western Electricity Coordinating Council		CIP 002 R2/R3/R4: Redundant and require revision. Each of these requirements requires an annual review of the Critical Asset list and Critical Cyber Asset list. WECC agrees these protections are required, however, the standard should be revised so either CIP 002-3 R4 is removed and CIP 002-3 R1-R3 are revised to require annual review and approval of the appropriate documentation, or CIP 002-3 R2 and R3 are revised to no longer require an annual review.CIP 005 R1.5/006 R3: These are redundant and should be removed/revised. CIP 006-3 R3 is redundant with CIP 005-3 R1.5. Either CIP 005-3 R1.5 should be revised to no longer require the protections of CIP 006-3 R3, or CIP 006-3 R3 should be removed and the content of CIP 006 R3 moved to CIP 005 R1.5.CIP 005 R1.5/006 R2.2: Redundant. Should be revised. Devices

Organization	Yes or No	Question 3 Comment
		applicable to these requirements may be redundant if they are classified as CCA (thus duplicated with CIP 002 - CIP 009) or reside within an ESP (thus duplicated with CIP 007). The requirements should be revised to take into account the situation where a device resides within an ESP or is classified as CCA, and is a device used in the EACM/PACM of ESPs/PSPs. Note: It appears this is being addressed in V.5 of CIP.CIP-005, R5: Should be removed and the protections highlighted in this requirement moved to appropriate requirements it references. This will cause less confusion with entities, and be more precise with exactly what documentation is required to be reviewed and approved.CIP 005 R5.1/R5.2: Redundant. Should revise CIP 005 R1.6 to include the wording of CIP 005 R5.1, and remove CIP 005 R5.1. This will cause less confusion with entities, and be better aligned with the CIP 005 R1.6 requirement.CIP 005 R5.3: Redundant. Should revise CIP 005 R3 to include the wording of this sub-requirement, and CIP 005 R5.3 should be removed. This change will create a better fit in the appropriate requirement, and be less confusing for entities.CIP 007 R9: Should be removed and the protections highlighted in this requirement moved to appropriate requirements it references. Thus CIP 007 requirements that require documentation should include the need to review and update the documentation. This will cause less confusion with entities, and be more precise with what documentation is required to be reviewed and approved.EOP-004-1 R3.2: Little, if any, value as a reliability requirement. This requirement points to attachments that could be addressed in the main part of the R3 standard. This requirement does nothing to promote the protection of the BES.VAR-001-2 R10: Redundant. The reliability purpose for R10 is to make sure that operators don't think that exceeding an SOL or IROL due to voltage issues is acceptable. There are multiple standards requiring operators not exceed and maintain an SOL or IROL with 30 minutes, regardless of the cause of the exceedance. These standards are TOP-001-2 R7, R11; TOP-004-2 R1; TOP-007-0 R2; TOP-008-1 R1.
Entergy Services, Inc.		CIP-006 R5 - A revision to the language in CIP-006 R5 is needed in order to require the review and handling of incidents of unauthorized access (when a door, gate or window has been opened without authorization), as opposed to what is more

Organization	Yes or No	Question 3 Comment
		accurately characterized as "unsuccessful" access attempts (e.g. invalid access card swipes). There currently is no definition of "unauthorized access attempts". The methods to be used for monitoring that are listed in the requirement, however do list: "Alarm Systems that alarm to indicate a door, gate or window has been opened without authorization". This method does not indicate that the alarm system must alarm on card swipes that do not result in the door opening, and be characterized as "Unauthorized Access attempts". Unsuccessful card swipes at a PSP access point, for example, do not suggest an unauthorized access attempt. A card swipe can be unsuccessful for a number of reasons, all of which are recorded by the key card system, such as the use of a deactivated card, an invalid card format, and a card not in the card file. An unsuccessful card swipe itself is not an indication that a PSP access point was “opened within authorization” because it does not indicate that the door has been opened in any manner. However, in the FAQ guidance for the CIP Reliability Standards, NERC acknowledged that Responsible Entities can consider single failed access attempts such as a single failed log-in not to be suspicious events requiring a response A single failed card swipe should be treated in the same way. The rewording of this requirement would address Criteria B-8 - "Hinders the protection or reliable operation of the BES." Investigating and documenting each unsuccessful card swipe would take a tremendous amount of time and produce a significant amount of paperwork without providing any additional physical security.CIP-005 R3 and CIP-006 R5 - Revisions to the wording around the timing of monitoring both physical and electronic access are needed. CIP-005 R3 - Monitoring Electronic Access states that "The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week." and CIP-006 R5 -Monitoring Physical Access stats that "The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in

Organization	Yes or No	Question 3 Comment
		Requirement CIP-008-3.The "twenty-four hours a day, seven days a week" portion of these requirements provides an unachievable requirement for 100% uptime for all systems used to monitor such access. The requirement should allow for a resonable amount of downtime. Either the "twenty-four hours a day, seven days a week" wording in these requirements could be removed altogether, or alternative langauge, such as requiring "High Availability" (for example 99.9% uptime) or some other wording that allowed for very small amounts of downtime that might be required for system reboots or minor maintenance.
SRC		Consider including the following standards for review in Phase II:BAL-004-0 - Time Error CorrectionMOD-030-2 - Flowgate MethodologyPRC-006-1 R8 (provision of data)PRC-006-1 R14 (administrative - response to written comments)
MidAmerican Energy Company		Consider the list provided by EEI.
Georgia System Operations Corporation		EOP-002-3, R1PER-001-0.1, R1Criteria B7, 9Statement: reference to BA or RC responsibilities and authority are within the criteria of NERC's Functional Model and so this is redundant. In addition, it is understood that these functions are substantial if not paramount for an entity to become certified as such. FAC-001-0 (all requirements)Criteria B 1, 3 and 6Statement: The requirement in FAC-001-0 to document and publish facility connection requirements has no impact on reliability. It is purely a document that those considering to interconnect with a transmission entity may review as a reference. All INT standardsCriteria B 1, 3 and 6Statement: Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Note: INT-007-1 R1.2 is part of Initial Phase. All data collection requirementsCIP-005-3a, 4a R5.3CIP-006c, -4c R7, R8.3CIP-007-3, -4 R5.1.2; R6.4; R7.3CIP-008-3, -4 R2PRC-018-1, R5Criteria B1,2 and 9Statement: These requirements are for data retention and although the need is

Organization	Yes or No	Question 3 Comment
		substancial, i.e. as a sort of forensic tool, they serve no function to reliability from an immediate time perspective.Standards currently requiring reporting.Criteria 1, 4 and 9EOP-002-3 R9.2EOP-004-1 R3 and its subrequirements; R4 and R5FAC-003-1 R3; FAC-003-1 R3.1: FAC-003-1 R3.2: FAC-003-1 R3.3: FAC-003-1 R3.4: FAC-003-1 R3.4.1: FAC-003-1 R3.4.2: FAC-003-1 R3.4.3: FAC-003-1 R4FAC-010-2.1 R5FAC-011-2 R5FAC-013-2 R6MOD-012-0 R2MOD-020-0 R1MOD-021-1 R3PRC-004-1a R3: PRC-004-2a R3: PRC-004-WECC-1 R.3.PRC-007-0 R2; PRC-007-0 R3; PRC-009-0 R2 PRC-011-0 R2; PRC-015-0 R3; PRC-016-0.1 R3; PRC-017-0 R2; PRC-021-1 R2TPL-001-0.1 R3; TPL-002-0b R3; TPL-003-0a R3; TPL-004-0 R2.Statement: These are all reporting requirements; they do not aid reliability from an immediate time perspective. If the Regional Entity desires to review information for purposes of monitoring reliability or assessing risk, the information should be collected via vehicles other than the Reliability Standards.Requirements applied to annual reviewsCriteria B1, 2,3 7 and 9CIP-002-2, -4 R4CIP-003-3, -4 R1.3; CIP-003-3, -4 R4.3; CIP-003-3, - 4 R5.1.2; CIP-003-3, - 4 R5.3CIP-006-3c, -4 R1.8CIP-007-3, -4 R9CIP-009-3, -4 R1EOP-005-1 R1; EOP-005-2 R3.1EOP-008-0 R1.7EOP-008-1 R5IRO-014-1 R4.3Statement: These requirements do not closely relate to operations of the Bulk Electric System. They would be better served as processes expected of entities to manage their compliance programs and processes. PRC-005-1b, R2Criteria B4, 9Statement: This requirement needs to be revised such that language is elminated as it refers to the entity providing to its RE within 30 days. MOD-016-1.1 and MOD-021-1 (all requirements) Criteria B 9Statement: MOD-016 through MOD-021 are all about long term load forecasting and reporting of actual loads. Most of this can be eliminated from the standards and replaced with a data collection process (e.g., DADS). Loads to be used in modeling should be incorporated in the data requirements of MOD-010 and MOD-012 and not a separate standard.
Electric Reliability Council of Texas, Inc.		ERCOT agrees with the ISO/RTO SCR comments. However, in addition to the SRC comments, ERCOT offers the following:ERCOT supports future phases of the P81 project to eliminate/retire reliability standards that do not facilitate BES reliability. ERCOT is reviewing all standards to that end, however, developing a list of additional

Organization	Yes or No	Question 3 Comment
		requirements for retirement will require additional time. The SDT should establish a prospective process that provides adequate time and opportunity for entities to perform a meaningful review of remaining requirements to determine which additional requirements warrant retirement and to develop appropriate criteria, if relevant, that may be incremental to the ones proposed in this SAR, and to develop appropriate retirement justifications based on the relevant retirement criteria.
City of Austin dba Austin Energy		FAC-001-0 (all requirements)Criteria B 1, 3 and 6Statement: The requirement in FAC-001-0 to document and publish facility connection requirements has no impact on reliability. It is purely a document that those considering to interconnect with a transmission entity may review as a reference. Once an interconnection request is actually made with a transmission owner, the transmission owner performs the FAC-002-1 steady-state, short-circuit, and dynamics studies to determine the new interconnection's impact on reliability. During the negotiation of an interconnection agreement the FAC-001-0 referenced material is agreed on and reduced to writing for purposes of constructing, maintaining and operating the interconnection facilities. Also, during the entire interconnection process, as FAC-002-1 provides for, the parties must coordinate and cooperate during the assessment of the reliability impact of the new interconnection facilities. Thus, FAC-001-0, at best, is a best practice or helpful initial guide to an entity considering interconnecting, but provides little, if any, meaningful value to reliability, especially when compared to the actual benefits to reliability via the FAC-002-1 studies, the execution of a negotiated agreement and the coordination of activities during constriction and operation of the new facilities. Accordingly, FAC-001-0 should be retired, and, if necessary, any requirements that protect reliability should be transferred to FAC-002-1. All INT Standards Criteria B 6, 7 and 9Statement: Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, we recommend that the Standards Drafting Team retire the INT Reliability Standards and, as necessary, transfer any requirement that protect

Organization	Yes or No	Question 3 Comment
		reliability to the BAL Reliability Standards. All data collection requirements not included in the Initial Phase, more specifically:CIP-005-3a, -4a R5.3CIP-006c, -4c R7, R8.3CIP-007-3, -4 R5.1.2; R6.4CIP-008-3, -4 R2PRC-018-1 R5Criteria B 1, 2 and 9Statement: These requirements are purely data retention requirements with no functional nexus to reliability and, therefore, best handled via compliance monitoring, RSAW or as a data request during an audit. All reporting out requirements not included in the Initial Phase, more specifically:EOP-002-3 R9.2EOP-004-1 R3 and its subrequirements; R4 and R5FAC-003-1 R3; FAC-003-1 R3.1: FAC-003-1 R3.2: FAC-003-1 R3.3: FAC-003-1 R3.4: FAC-003-1 R3.4.1: FAC-003-1 R3.4.2: FAC-003-1 R3.4.3: FAC-003-1 R4FAC-010-2.1 R5FAC-011-2 R5FAC-013-2 R6MOD-012-0 R2MOD-020-0 R1MOD-021-1 R3PRC-004-1a R3: PRC-004-2a R3: PRC-004-WECC-1 R.3.PRC-007-0 R2; PRC-007-0 R3; PRC-009-0 R2 PRC-011-0 R2; PRC-015-0 R3; PRC-016-0.1 R3; PRC-017-0 R2; PRC-021-1 R2TPL-001-0.1 R3; TPL-002-0b R3; TPL-003-0a R3; TPL-004-0 R2.Criteria B 1, 4 and 9Statement: There is no direct connection between reporting out of information to an entity or Regional Entity and protecting reliability. If the Regional Entity desires to review information for purposes of monitoring reliability or assessing risk, the information should be collected via vehicles other than the Reliability Standards.Annual reviewsCIP-002-3, R3; CIP-002 -4 R3CIP-003-3, -4 R1.3; CIP-003-3, -4 R4.3; CIP-003-3, - 4 R5.1.2; CIP-003-3, - 4 R5.3CIP-006-3c, -4 R1.8CIP-007-3, -4 R9CIP-009-3, -4 R1EOP-005-1 R1; EOP-005-2 R3.1EOP-008-0 R1.7EOP-008-1 R5IRO-014-1 R4.3Criteria B 1, 2, 3, 7 and 9Statement: The annual review and update requirements are arbitrary, administrative and not aligned with the operation and protection of the Bulk Electric System. These requirements should be retired or modified to align with how the Bulk Electric System is operated and protected. Other requirementsCIP-007-3, -4 R7 Criteria B 1, 2, 3 and 7Statement: The essential elements of the process of disposing or redeploying of Cyber Assets and the associated cyber security are set forth in R7.2 and R7.3. To require “formal methods, processes and procedures” appears to require formal documentation for the sake of documentation, rather than allowing the responsible entity to implement a process that achieves the actions required in R7.2 and R7.3,

Organization	Yes or No	Question 3 Comment
		which may or may not include formal procedures, for example. EOP-004-1 R2Criteria B 7 Statement: The analysis of the BES for system disturbances is covered in PRC-004-2.1a R1. The PRC Requirement R1 calls for the analysis of its transmission Protection System Misoperations. We believe that BES analysis is covered inherently through this PRC standard making EOP-004 R1 redundant to the PRC standard.Another factor is the Version 2 of the EOP-004-2 where the requirement to analyze the BES disturbance is noticeably absent. The focus on the EOP-004 is for the reporting of applicable events that are identified in the PRC-004 standard. There is an event analysis reporting process referenced in the NERC Rules of Procedures (ROPs) that handles this requirement. Therefore, this is a redundant requirement. In February of 2012, NERC deployed its Events Analysis Process - incorporating the learnings from two field trials held over the previous year and a half. It includes all the necessary steps that affected operators must take to analyze and report on events that may impair the reliability of the BES. Most Regional Entities have already updated their reporting procedures to match NERC's. Furthermore, NERC and the Regional Entities already have sufficient authority to order analyses and corrective action plans outside of the Reliability Standards. These are important steps for the development of Lessons Learned and trending analyses, but do not contribute to reliable operations. In fact, the demand for near term reporting - some within one hour of the initiation of the event - interferes with the efforts of front-line personnel to mitigate the issue at handBAL-001-0.1a (all requirements), BAL-004-0 (all requirements), BAL-005-0.1b R11; BAL-006-2 (all requirements)Criteria B 6 and 9Statement: BAL-001 requires a 12 month rolling average of ACE and does not impact reliability and should be eliminated (in favor of BAL-002). Consider augmenting NAESB standard WEQ-005.BAL-004 requirement for time error correction is not important for reliability and should be eliminated. It also duplicates NAESB std WEQ-006.In BAL-005 R11, Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE, is not needed for reliability. Ramp rates have minimal impact on ACE calculations, and are already included in the

Organization	Yes or No	Question 3 Comment
		definition of Interchange Schedule in the NERC Glossary as used in R9. The requirement to use agreed upon ramp rates is commercial in nature and is already covered by NAESB standard WEQ-004-17.BAL-006-2 is an after-the-fact accounting of inadvertent interchange and does not impact reliability and should be eliminated. Consider augmenting NAESB standard WEQ-007.CIP-003-3, -4 R2 and its subrequirementsCriteria B 1 and 9Statement: Whether the entity has a robust up-to-date CIP compliance plan may impact reliability, but not whether there is an employee called a CIP senior manager oversees the plan. CIP-004-3, -4 R2.3 Criteria B 9Statement: Whether the entity has a robust up-to-date, trained-on CIP compliance plan may impact reliability, but not whether there is annual training. CIP-004-3, -4 R3.2Criteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan may impact reliability, but not whether there is a seven year update to the PRA. CIP-004-3, -4 R4.1Criteria B 1, 9Statement: Whether the entity has a robust up-to-date on CIP compliance plan may impact reliability, but not whether it reviews lists every seven days. CIP-004-3, -4 R4.2Criteria B 1, 9Statement: Whether the entity has a robust up-to-date on CIP compliance plan may impact reliability, but not whether it revokes access within 24 hours or 7 days. CIP-005-3a, -4a R2.5 and its subrequirementsCriteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan to protect the ESP may impact reliability, but not whether specific information is documented. CIP-007-3, -4 R3.1, R3.2Criteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan to protect the PSP may impact reliability, but not whether specific information is documented within 30 days. Also, whether the entity has a robust up-to-date on CIP compliance plan to protect the PSP may impact reliability, but not whether specific information is documented. CIP-008-3 R1.4Criteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan may impact reliability, but not whether specific information is documented within 30 days or a change. EOP-001-1b, -2bCriteria B 7Statement: Duplicative with the other EOP Standards (e.g., Capacity and Energy emergency of EOP-002, Load Shedding of EOP-003, and System Restoration of EOP-005).EOP-002-3 R1Criteria B 7Statement: Duplicates other

Organization	Yes or No	Question 3 Comment
		requirements such as IRO-001-1 R8 and should be retired or modified to reduce redundancy. EOP-002-3 R9 Criteria B 7Statement: When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources). It duplicates NAESB standard WEQ-008 and should be eliminated.EOP-005-2 R1.2.A description of how all Agreements or mutually agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration. Criteria B 1, 3 and 7 Statement: With the implementation of NUC-001-2 R2, there is no longer a need for EOP-005-2 R1.2. Specifically, NUC-001-2 R2 requires Nuclear Plant Interface Requirements (NPIRs) to be included in the agreements for operation and maintenance (including restoration process) for off-site nuclear power:R2. The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements1 that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs.Given the off-site power requirements of NUC-001-2 which require comprehensive operational interface protocols (including restoration) between nuclear plants and responsible entities as part of the NPIRs, there is no longer a need for the administrative, documentation-only requirement in EOP-005-2 related to the same subject matter.IRO-002-2 (all requirements)Criteria B 7Statement: Redundant with COM-002-2, R1 COM-001-1.1, R1 and IRO-002-2, R2 and R3IRO-005-3a R10Criteria B 9Statement: Confusing requirement. It was intended to address rare cases where entities were told to operate to different SOLs and IROLs. However, because only the TOP and the RC can see these parameters, the only thing a GOP can do is follow a directive.IRO-014-1 R4Criteria B 9Statement: Requirement 4 (including sub-parts) should be rolled up into R1. and eliminated. Requirement 1 should be modified to require "current operating procedures, processes or plans with all adjacent RCs.IRO-015-1 R2.1Criteria B1 and 9Statement: Whether the procedure, process and plan is

Organization	Yes or No	Question 3 Comment
		robust and up-to-date may impact reliability, not whether there are weekly calls.MOD-001-1 and MOD-008-1 (all requirements)Criteria 6 and 9Statement: Do the ATC / TTC standards belong in NERC or NAESB (i.e., MOD-001, MOD-004, MOD-008, MOD-028 thru 030, and TOP-002-2 R12)? I think NERC should be focused on managing SOLs and IROLs, whereas NAESB on TTC, ATC, etc., and I think these can/should be moved to the NAESB standards.Criteria B 6 and 9Statement: This could be handled as a data request from an RE or other Registered Entities and, therefore, would not need a requirement, as there are too many requirements that warrant an attestation that no request was made.MOD-016-1.1 and MOD-021-1 (all requirements) Criteria B 9Statement: MOD-016 through MOD-021 are all about long term load forecasting and reporting of actual loads. Most of this can be eliminated from the standards and replaced with a data collection process (e.g., DADS). Loads to be used in modeling should be incorporated in the data requirements of MOD-010 and MOD-012 and not a separate standard.MOD-028-1 (all requirements); MOD-029-1a (all requirements); MOD-030-2 (all requirements)Criteria B 6 and 9Statements: ATC / TTC standards should belong NAESB (i.e., MOD-001, MOD-004, MOD-008, MOD-028 thru 030, and TOP-002-2 R12)? NERC should focus on managing SOLs and IROLs, whereas NAESB on TTC, ATC, etc.PRC-022-1 R1, R1.1, R1.2, R1.3, R1.4, and R1.5Criteria B 7Statement: Whether the responsible entity has robust UVLS misoperation and correction action is redundant with PRC-004-1a, -2a. TOP-001-1a R3 and R7 (and its subrequirements)Criteria B 9Statement: For R3, there are three projects in progress addressing the issuance of directives by the RC, BA and TOP. Also, for R7, all outages information should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-002-2b R8 and R 9Criteria B 6, 7 and 9Statement: “Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency”, duplicates VAR-001 and should be eliminated. “Each Balancing Authority shall plan to meet Interchange Schedules and ramps” duplicates the BAL standards and the NEASB standards and should be eliminated.TOP-002-2b R12Criteria B 6 and 9Statement: ATC / TTC standards should belong to NAESB (i.e., MOD-001, MOD-004, MOD-008,

Organization	Yes or No	Question 3 Comment
		MOD-028 thru 030, and TOP-002-2 R12). NERC should focus on managing SOLs and IROLs, whereas NAESB on TTC, ATC, etc., These can/should be moved to the NAESB standard.TOP-002-2b R14 and R14.1Criteria B 9Statement: All derating information should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-002-2b R15Criteria B 9Statement: Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations is a "how" requirement that is needed to meet other requirements in the standard. It is also not measureable, and the requirement should be eliminated. All weekly forecasts should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-003-1 R1 and its subrequirements; R2 and R3Criteria B 9Statement: All planned outage information should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-005-2a R3Criteria B 9Statement: PSEs are not best positioned to provide reliability information.BAL-005-0.1b R1Criteria B7Statement: Introductory statement; redundant with subrequirements MOD-010-0 R2Criteria B 1, 4 and 9Statement: MOD-012-0 R2 was included in the Joint Trade Associations list of suggested requirements for retirement or modification. MOD-010-0 R2 is nearly identical to MOD-012-0 R2 and should also be considered.PER-001-0.1 R1Criteria B7Statement: The TOP portion of this requirement is redundant with TOP-001-1a R1PRC-018-1 R3 (and all sub requirements)Criteria B2 and 4Statement: This requirement involves data collecting and reporting that does not impact the reliability of the BES; could be part of a data request if necessary
Georgia Transmission Corporation		FAC-001-0 (all requirements)Criteria B 1, 3 and 6Statement: The requirement in FAC-001-0 to document and publish facility connection requirements has no impact on reliability. It is purely a document that those considering to interconnect with a transmission entity may review as a reference. MOD-016-1.1 and MOD-021-1 (all requirements) Criteria Meets Criteria A and a combination of either or all of B1, B2, B3, B4, B 9Statement: MOD-016 through MOD-021 are about long term load forecasting and reporting of actual and forecast loads. Requirements could be eliminated from the standards and replaced with a data collection process (e.g.,

Organization	Yes or No	Question 3 Comment
		TADS/DADS, etc.). Loads to be used in modeling could be incorporated in the data requirements of MOD-010 and MOD-012 and not a separate standard. Additionally, MODs-016 through 021 have yet to be classified as Tier 1, 2, or 3; nor have they yet to be identified on NERC's Actively Monitored List.PRC-006-1 (R7, R8, and R14) Criteria: Meets Criteria A and a combination of either or all of B1, B3, B4, B9Statement: Recommend these requirements to be eliminated from the standards and replaced with a data collection and or reporting process (e.g., TADS/DADS, etc.). PRC-023-1 (R3.3) Criteria: Meets Criteria A and a combination of either or all of B1, B4, B9Statement: Recommend these requirements to be eliminated from the standards and replaced with a data reporting process.TOP-001-1a (R4) Criteria: Meets Criteria A and B1Statement: Same requirement as TOP-001-1a (R3) which made the Phase I list, only difference is applicability.
Occidental Power Services, Inc.		If the changes listed in Question 2 are not considered in Phase 1, then they should be considered in subsequent phases of the project.
Illinois Municipal Electric Agency		IRO-010-1a R3
Idaho Power Company		MOD-017-0.1 R1.1, R1.2 Criterion B2MOD-018-0 R1 Criterion B7 (Should be covered by MOD-016)MOD-021-1 R1, R2 Criterion B7 (Should be covered by MOD-016)MOD-021-1 R3 Criterion B4
CPS Energy		No additional comments.
Salt River Project		No additions at this time.
Occidental Energy Ventures Corp.		OEVC agrees with the process that the Trades are using to approach this question, but do not agree with some of their priorities. OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be

Organization	Yes or No	Question 3 Comment
		removed:a) BAL-005, R1.1 - BA metering is financial in nature. Telemetry is already required for reliability.b) TOP-002, R13 - Generator validations are driven by the regions already.FAC-001-0 (all requirements)Criteria B 1, 3 and 6Statement: OEVC agrees with the Trade's analysis, but will also point out that once connection requirements are in place, they will rarely change. We believe this would mean a lower priority is in order. All INT Standards Criteria B 6, 7 and 9 Statement: Again, OEVC agrees with the Trades on this. It may even be time to suggest that the functional designation of the PSE go away. They serve a marketing purpose and are blind to reliability indicators. All data collection requirements not included in the Initial PhaseCIP-005-3a, -4a R5.3CIP-006c, -4c R7, R8.3CIP-007-3, -4 R5.1.2; R6.4; R7.3CIP-008-3, -4 R2PRC-018-1 R5Criteria B 1, 2 and 9 Statement: OEVC agrees with the Trades. Most of these are captured in Phase I. These fit in the same category. All reporting out requirements not included in the Initial PhaseCIP-001-2a R3 should be modified to eliminate the word "reporting" (added by OEVC)EOP-002-3 R9.2EOP-004-1 R3 and its sub requirements; R4 and R5 FAC-003-1 R3; FAC-003-1 R3.1: FAC-003-1 R3.2: FAC-003-1 R3.3: FAC-003-1 R3.4: FAC-003-1 R3.4.1: FAC-003-1 R3.4.2: FAC-003-1 R3.4.3: FAC-003-1 R4FAC-010-2.1 R5FAC-011-2 R5FAC-013-2 R6MOD-010-0 R2 Similar to MOD-012-0 (added by OEVC)MOD-012-0 R2MOD-020-0 R1MOD-021-1 R3PRC-004-1a R3: PRC-004-2a R3: PRC-004-WECC-1 R.3.PRC-007-0 R2; PRC-007-0 R3; PRC-009-0 R2 PRC-011-0 R2; PRC-015-0 R3; PRC-016-0.1 R3; PRC-017-0 R2; PRC-021-1 R2TPL-001-0.1 R3; TPL-002-0b R3; TPL-003-0a R3; TPL-004-0 R2.Criteria B 1, 4 and 9 Statement: In addition to the Trade's comments, OEVC believes that NERC has an Events Analysis process, RAPA process, and Section 1600 Data Request process that they can invoke to get this information.Annual reviewsCIP-002-2, -4 R4CIP-003-3, -4 R1.3; CIP-003-3, -4 R4.3; CIP-003-3, - 4 R5.1.2; CIP-003-3, - 4 R5.3CIP-006-3c, -4 R1.8CIP-007-3, -4 R9CIP-009-3, -4 R1EOP-005-1 R1; EOP-005-2 R3.1EOP-008-0 R1.7EOP-008-1 R5IRO-014-1 R4.3Criteria B 1, 2, 3, 7 and 9 Statement: OEVC agrees with the Trades and add that Compliance teams spend far too much time trying to confirm that a RBAM was reviewed and signed off-on. This serves only to add time and expense - especially when conditions have not changed in the preceding year.

Organization	Yes or No	Question 3 Comment
		Other requirements EOP-004-1 R2 Criteria B 7 Statement: OEVC agrees with the Trades. Again, NERC has an Events Analysis process and RAPA process that they can invoke to require analyses. FAC-002-1 R1OEVC agrees that this requirement and five sub-requirements are unnecessary. First of all, the PUC, the BA, and the TOP are highly involved in the interconnection process. It is not clear what extra value is provided by overlapping oversight from the RE and/or NERC. Second, other standards - the TPLs in particular - are directly referenced in the requirement. Those are enforceable already, there is no need to duplicate them here.FAC-008-1 R1.3.5This requirement is already addressed in Phase I.IRO-001-1.1 R8 OEVC believes the intent is to consolidate RC directives in IRO-001 with TOP directives in TOP-001. Since Phase I addresses TOP-001, this seems to have been already accomplished.IRO-005-3a R10Criteria B 9Statement: OEVC agrees with the Trades. This is one that we propose should be a much higher priority. Since the GOP is already told to follow a directive, this requirement makes no sense. MOD-017-0.1 R1.1 and MOD-018-0 (all requirements) ; MOD-020-1 R1OEVC believes that this is redundant with IRO-010 and the new version of TOP-003 when it takes effect.MOD-019-0.1 R1OEVC believes that this is redundant with IRO-010 and the new version of TOP-003 when it takes effect. TOP-002-2b R2; R15OEVC believes that TOP-002 R15 will be resolved by the release of the new TOP standards.TOP-002-2b R14 and R14.1Criteria B 9Statement: OEVC believes that TOP-002 R14 and R14.1 will be resolved by the release of the new TOP standards.TOP-003-1 R1 and its sub requirements; R2 and R3Criteria B 9Statement: OEVC believes that these items will be resolved by the release of the new TOP standards.TOP-005-2a R3Criteria B 9Statement: OEVC agrees with the Trades on this one. Again, it may even be time to suggest that the functional designation of the PSE go away. TOP-006-2 R1.1, R4, R5, R6; TOP-008-1 R2, R4 OEVC believes that that TOP-006 R1.1 will be resolved by the release of the new TOP standards.
NERC Staff Technical Review		Please see NERC Staff's response to question 2 for Phase I requirements that NERC Staff recommends be reviewed for inclusion in a future phase. NERC Staff may propose additional requirements for a future phase of the P81 project at a later date.

Organization	Yes or No	Question 3 Comment
American Electric Power		Please see the response to Question #2 for additional Reliability Standard requirements that AEP would like to be considered as candidates for retirement on this initial, or subsequent, request for comment.
seattle city light		Seattle City Light supports the consolidated comments of the industry Trade Organizations.
Tampa Electric Company		Tampa Electric suggests that the P81 Drafting Team consider the adoption of concepts from the CIP version 5 criteria for consideration under CIP version 3 and 4. In particular Tampa Electric proposes that draft language for CIP-007 patching will reduce administrative burden for compliance with patching process TFEs under current versions (CIP-007 V3 and V4). The version 5 draft Guidelines and Technical Basis for CIP-007 V5 states: R2.1 A patch source is not required for Cyber Assets that have no updateable software or firmware (there is no user accessible way to update the internal software or firmware executing on the Cyber Asset), or those Cyber Assets that have no existing source of patches such as vendors that no longer exist. R2.2 Determination that a security related patch, hotfix, and/or update poses too great a risk to install on a system or is not applicable due to the system configuration should not require a TFE.
Manitoba Hydro		The following statement should be removed from the standard as it does not support reliability of the BES [B8]:FAC-013-2 R5. 'However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request'The following statement should be removed from the standard as it does not support reliability or provide any protection to the BES. [B8]:FAC-013-2 R6. 'If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to

Organization	Yes or No	Question 3 Comment
		that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information'.
The Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), the Electric Power Supply Association (EPSA), the Transmission Access Policy Study Group (TAPS), Electricity Consumers Resource Council (ELCON), the American Public Power Association (APPA), the Large Public Power Council (LPPC) and, the Canadian Electricity Association (CEA) (collectively, the Trade Associations).		The Trade Associations support the following list of Reliability Standard requirements to be retired or modified in a subsequent phase of the P81 project. To assist the Standards Drafting Team decide what should be considered in phase 2, phase 3 etc., the Trade Associations have listed the requirements in the order of importance - with those at the top of the list candidates for phase 2. The Trade Associations understand, however, that the decision on how best to proceed with phase 2, phase 3 will be weighed by the Standards Drafting Team, and, therefore, have not indicated any bright line on what should or should not be included in phase 2 versus phase 3, etc. The Trade Associations further note that the list of requirements listed below may be supplemented with additional requirements as the phase 2/phase 3 discussions evolve. Additionally, the Trade Associations believe that additional criteria for elimination may be proposed as part of the phase 2/phase 3 process.FAC-001-0 (all requirements)Criteria B 1, 3 and 6Statement: The requirement in FAC-001-0 to document and publish facility connection requirements has no impact on reliability. It is purely a document that those considering to interconnect with a transmission entity may review as a reference. Once an interconnection request is actually submitted to a transmission owner, the transmission owner performs the FAC-002-1 steady-state, short-circuit, and dynamics studies to determine the new interconnection's impact on reliability. During the negotiation of an interconnection agreement the FAC-001-0 reference material is agreed on and reduced to writing for purposes of constructing, maintaining and operating the interconnection facilities. Also, FAC-002-1 imposes an obligation on the parties to coordinate and cooperate during the assessment of the reliability impact of the new interconnection facilities. Thus, FAC-001-0, at best, is a best practice or helpful initial guide to an entity considering interconnecting, but provides little, if any, meaningful value to reliability, especially when compared to the actual benefits to reliability via the FAC-002-1

Organization	Yes or No	Question 3 Comment
		studies, the execution of a negotiated agreement and the coordination of activities during construction and operation of the new facilities. Accordingly, FAC-001-0 should be retired, and, if necessary, the transfer of any requirements that protect reliability to FAC-002-1. All INT Standards (With the exception of INT-007-1 R1.2 which is part of and should remain in the Initial Phase.)Criteria B 6, 7 and 9 Statement: Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards. ALL DATA COLLECTION REQUIREMENTS NOT INCLUDED IN THE INITIAL PHASECIP-005-3a, -4a R5.3CIP-006-3c, -4c R7, R8.3CIP-007-3, -4 R5.1.2; R6.4CIP-008-3, -4 R2PRC-018-1 R5Criteria B 1, 2 and 9Statement: These requirements are purely a data retention requirement with no functional nexus to reliability, and, therefore, are best handled via compliance monitoring, RSAWs or as a data request during an audit.ALL REPORTING OUT REQUIREMENTS NOT INCLUDED IN THE INITIAL PHASEEOP-002-3 R9.2EOP-004-1 R3 and its subrequirements; R4 and R5FAC-003-1 R3; FAC-003-1 R3.1: FAC-003-1 R3.2: FAC-003-1 R3.3: FAC-003-1 R3.4: FAC-003-1 R3.4.1: FAC-003-1 R3.4.2: FAC-003-1 R3.4.3: FAC-003-1 R4FAC-010-2.1 R5FAC-011-2 R5FAC-013-2 R6MOD-012-0 R2MOD-020-0 R1MOD-021-1 R3PRC-004-1a R3: PRC-004-2a R3: PRC-004-WECC-1 R.3.PRC-007-0 R2; PRC-007-0 R3; PRC-009-0 R2; PRC-011-0 R2; PRC-015-0 R3; PRC-016-0.1 R3; PRC-017-0 R2; PRC-021-1 R2TPL-001-0.1 R3; TPL-002-0b R3; TPL-003-0a R3; TPL-004-0 R2.Criteria B 1, 4 and 9Statement: There is no direct nexus between reporting out of information to an entity or Regional Entity and protecting reliability. If the Regional Entity desires to review information for purposes of monitoring reliability or assessing risk, the information should be collected via vehicles other than the Reliability Standards.Annual reviewsCIP-002-3, R3; CIP-002 -4 R3CIP-003-3, -4 R1.3; CIP-003-3, -4 R4.3; CIP-003-3, - 4 R5.1.2; CIP-003-3, - 4 R5.3CIP-006-3c, -4 R1.8CIP-007-3, -4

Organization	Yes or No	Question 3 Comment
		R9CIP-009-3, -4 R1EOP-005-1 R1; EOP-005-2 R3.1EOP-008-0 R1.7EOP-008-1 R5IRO-014-1 R4.3Criteria B 1, 2, 3, 7 and 9Statement: The annual review and update requirements are arbitrary, administrative and not aligned with the operation and protection of the Bulk Electric System. These requirements should be retired or modified to align with how the Bulk Electric System is operated and protected. OTHER REQUIREMENTSCIP-007-3, -4 R7 Criteria B 1, 2, 3 and 7Statement: The essential elements of the process of disposing or redeploying of Cyber Assets and the associated cyber security are set forth in R7.2 and R7.3. To require "formal methods, processes and procedures" appears to require formal documentation for the sake of documentation, rather than allowing the responsible entity to implement a process that achieves the actions required in R7.2 and R7.3, which may or may not include formal procedures, for example. EOP-004-1 R2Criteria B 7 Statement: The analysis of the BES for system disturbances is covered in the PRC-004-2.1a R1. The PRC Requirement R1 calls for the analysis of its transmission Protection System Misoperations. We believe that BES analysis is covered inherently through this PRC standard, making EOP-004 R1 redundant to the PRC standard. Another factor that was considered is the notable absence of any requirement in EOP-004-2 to analyze the BES disturbance. The focus of EOP-004 is on the reporting of applicable events that are identified in the PRC-004 standard. There is an event analysis reporting process referenced in the NERC Rules of Procedures (ROP) that addresses this requirement. Therefore, this is a redundant requirement. In February of 2012, NERC deployed its Events Analysis Process - incorporating the learnings from two field trials held over the previous year and a half. It includes all the necessary steps that affected operators must take to analyze and report on events that may impair the reliability of the BES. Most Regional Entities have already updated their reporting procedures to match NERC's. Furthermore, NERC and the Regional Entities already have sufficient authority to order analyses and corrective action plans outside of the Reliability Standards. These are important steps for the development of Lessons Learned and trending analyses, but do not contribute to reliable operations. In fact, it is arguable that the demand for near term reporting - some within one hour of the

Organization	Yes or No	Question 3 Comment
		initiation of the event - interferes with the efforts of front-line personnel to mitigate the issue at hand BAL-004-0 (all requirements), BAL-005-0.1b R11; BAL-006-2 (all requirements)Criteria B 6 and 9Statement: BAL-004 requirement for time error correction is not important for reliability and should be eliminated. BAL-004 also duplicates NAESB standard WEQ-006.BAL-005 R11 states that Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE. This requirement is not needed for reliability. Ramp rates have minimal impact on ACE calculations, and are already included in the definition of Interchange Schedule in the NERC Glossary as used in R9. The requirement to use agreed upon ramp rates is commercial in nature and is already covered by NAESB standard WEQ-004-17.BAL-006-2 is an after the fact accounting of inadvertent interchange and does not impact reliability and should be eliminated. Consider augmenting NAESB standard WEQ-007. CIP-003-3, -4 R2 and its subrequirementsCriteria B 1 and 9Statement: Whether the entity has a robust up-to-date CIP compliance plan may impact reliability, but not whether there is an employee called a CIP senior manager that oversees the plan. CIP-004-3, -4 R2.3 Criteria B 9Statement: Whether the entity has a robust up-to-date, trained-on CIP compliance plan may impact reliability, but not whether there is annual training. CIP-004-3, -4 R3.2Criteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan may impact reliability, but not whether there is a seven year update to the personnel risk assessment(PRA). CIP-004-3, -4 R4.1Criteria B 1, 9Statement: Whether the entity has a robust up-to-date on CIP compliance plan may impact reliability, but not whether it reviews lists every seven days. CIP-005-3a, -4a R2.5 and its subrequirementsCriteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan to protect the ESP may impact reliability, but not whether specific information is documented. CIP-007-3, -4 R3.1, R3.2Criteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan to protect the PSP may impact reliability, but not whether specific information is documented within 30 days. Also, whether the entity has a robust up-to-date CIP compliance plan to protect the PSP may impact reliability, but

Organization	Yes or No	Question 3 Comment
		not whether specific information is documented. CIP-008-3 R1.4Criteria B 1, 9Statement: Whether the entity has a robust up-to-date CIP compliance plan may impact reliability, but not whether specific information is documented within 30 days or a change. EOP-001-1b, -2bCriteria B 7Statement: Duplicative with the other EOP Standards (e.g., Capacity and Energy emergency of EOP-002, Load Shedding of EOP-003, and System Restoration of EOP-005).EOP-002-3 R1Criteria B 7Statement: Duplicative of other requirements such as IRO-001-1 R8, and should be retired or modified to reduce redundancy. EOP-002-3 R9 Criteria B 7Statement: When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources). It is duplicative of NAESB standard WEQ-008 and should be eliminated.EOP-005-2 R1.2.A description of how all Agreements or mutually agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration. Criteria B 1, 3 and 7 Statement: With the implementation of NUC-001-2 R2, there is no longer a need for EOP-005-2 R1.2. Specifically, NUC-001-2 R2 requires Nuclear Plant Interface Requirements (NPIRs) to be included in the agreements for operation and maintenance (including restoration process) for off-site nuclear power:Ref: NUC-001-2 R2. The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements1 that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs.Given the off-site power requirements of NUC-001-2 which require comprehensive operational interface protocols (including restoration) between nuclear plants and responsible entities as part of the NPIRs, there is no longer a need for the administrative, documentation-only requirement in EOP-005-2 related to the same subject matter.FAC-013-1 (all requirements)Criteria B 6Statement: It is really a commercial planning practice suitable for Order 1000 under Section 205/206 as opposed to Section 215.IRO-002-2 (all requirements)Criteria B

Organization	Yes or No	Question 3 Comment
		7Statement: Redundant with COM-002-2, R1 COM-001-1.1, R1 and IRO-002-2, R2 and R3IRO-005-3a R10Criteria B 9Statement: Confusing requirement. It was intended to address rare cases where entities were told to operate to different SOLs and IROLs. However, since only the TOP and the RC can see these parameters, the only thing a GOP can do is follow a directive.IRO-014-1 R4Criteria B 9Statement: Requirement 4 (including sub-parts) should be rolled up into R1 and eliminated. Requirement 1 should be modified to require "current operating procedures, processes or plans with all adjacent RCs.IRO-015-1 R2.1Criteria B1 and 9Statement: Whether the procedure, process and plan is robust and up-to-date may impact reliability, not whether there are weekly calls. MOD-001-1 and MOD-008-1 (all requirements)Criteria B 6 and 9Statement: NERC should be focused on modeling the BES and managing SOLs and IROLs, the methodologies for the determination of CBM, TTC and ATC are commercial matters associated with the reservation and allocation of rights to transfer capability among transmission customers. While transfer capability calculations should be based on models of the BES, the NAESB WEQ should address the issues raised in MOD-001, MOD-004, MOD-008, MOD-028 thru 030, and TOP-002-2 R12.Criteria B 6 and 9Statement: This could be handled as a data request from an RE or other Registered Entities, and therefore would not need a requirement, as there are too many requirements that warrant an attestation that no request was made.MOD-016-1.1 and MOD-021-1 (all requirements) Criteria B 9Statement: MOD-016 through MOD-021 are all about long term load forecasting and reporting of actual loads. Most of this can be eliminated from the standards and replaced with a data collection process (e.g., DADS). Loads to be used in modeling should be incorporated in the data requirements of MOD-010 and MOD-012 and not a separate standard.MOD-019-0.1 R1Criteria B 1, 2, and 9Statement: MOD-019-0.1 covers “Reporting of Interruptible Demands and Direct Control Load Management,” which requires reporting of a forecast of interruptible demand and direct control load management data. This reporting is administrative in nature, and the information is not important for reliability. The data is best gathered through DADS and not through a standard.MOD-028-1 (all requirements); MOD-029-1a (all requirements);

Organization	Yes or No	Question 3 Comment
		MOD-030-2 (all requirements)Criteria B 6 and 9Statement: Do the ATC / TTC standards belong in NERC or NAESB (i.e., MOD-001, MOD-004, MOD-008, MOD-028 thru 030, and TOP-002-2 R12)? I think NERC should be focused on managing SOLs and IROLs, whereas NAESB on TTC, ATC, etc., and I think these can/should be moved to the NAESB standards. PRC-011-0 R1 Criteria B 4 and 9Statement: Requirements for maintenance of under-frequency load shedding systems ("UFLS") and under-voltage load shedding systems ("UVLS") are not needed to meet an adequate level of BES reliability. UFLS and UVLS installations are widely distributed. Distribution circuit outages, distribution field switching, and varying load profiles, such as peak and off-peak, could impact the amount of load that would be automatically shed by UFLS and UVLS. Therefore, entities must include adequate margins above their obligation to be able to meet the obligated load shed at all times as required by Reliability Standards, such as PRC-006 and PRC-007, that are performance-based, or results-based. While UFLS and UVLS are, of course, important safety-net systems, PRC-011-0 R 1 maintenance requirement is not needed to provide a "defense-in-depth" approach due to the margins required to meet performance-based requirements. Thus, Like PRC-008-0 R1 included in Phase I, Reliability Standard PRC-011-0 R1 which involves maintenance of UVLS, is not needed. In fact, it is typically the same relays and associated equipment that provides both the UFLS and the UVLS functions. PRC-022-1 R1, R1.1, R1.2, R1.3, R1.4, and R1.5Criteria B 7Statement: Whether the responsible entity has robust UVLS misoperation and correction action is redundant with PRC-004-1a, -2a. TOP-001-1a R7 (and its subrequirements)Criteria B 9Statement: For R3, there are three projects in progress addressing the issuance of directives by the RC, BA, and TOP. This includes COM-003-1's requirements for the issuances of "not quite directives" Also, for R7 All outages information should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-002-2b R8 and R 9Criteria B 6, 7 and 9Statement: "Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency", is duplicative of VAR-001 (and incorrect) and should be eliminated. "Each Balancing Authority shall plan to meet Interchange Schedules and ramps", is duplicative of the

Organization	Yes or No	Question 3 Comment
		BAL standards and the NAESB standards and should be eliminated.TOP-002-2b R12Criteria B 6 and 9Statement: The ATC / TTC standards may belong in NAESB (i.e., MOD-001, MOD-004, MOD-008, MOD-028 thru 030, and TOP-002-2 R12)? NERC standards should be focused on managing SOLs and IROLs, whereas NAESB on TTC, ATC, etc.TOP-002-2b R14 and R14.1Criteria B 9Statement: All derating information should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-002-2b R15Criteria B 9Statement: Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations is a "how" requirement that is needed to meet other requirements in the standard. It is also not measureable, and the requirement should be eliminated. All weekly forecasts should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-003-1 R1 and its subrequirements; R2 and R3Criteria B 9Statement: All planned outage information should be submitted to the TOP and/or BA in accordance with their data requirements.TOP-005-2a R3Criteria B 9Statement: PSEs are not best positioned to provide reliability information.
SPP Standards Review Group		VAR-002 R3 Status changes on AVRs - Quite often status changes to AVRs may be made for only a matter of seconds. These changes do not impact the reliability of the BES but still require a call be made for notification of the change. Perhaps the requirement could be changed such that only status changes which impact the BES need to be reported. This hits on Items 4, 5, 8 and 9 in Criterion B.FAC-003-1 R1.3 - Specific training is required for personnel involved with vegetation management programs. This requirement is purely administrative (Criterion B.1) and does not, in and of itself, benefit the reliability of the BES. (Although this requirement has been removed in subsequent versions of this standard (FAC-003-2 and FAC-003-3), it remains in effect today. It needs to be retired.)While we don't have an extensive list at this time, we would hope that the drafting team will ask for potential candidates which fit this category at some point in the future prior to the start of work on the latter phases of the project.

Organization	Yes or No	Question 3 Comment
Ameren		We support and agree with Trade Association's comments and their suggested list of Reliability Standard requirements to be retired or modified in the subsequent phase of the P81 Project. In addition, we suggest that IRO-005-3, R10 should be modify to eliminate its applicability to LSE and PSE in addition to GOP. While the IRO-005-3_1a, R10 is necessary for the reliable operation of the BES, its applicability to LSE and PSE also is questionable as these entities do not "operate" the BES. We believe that it is redundant (criteria B7) with other requirements where these entities (GOP, LSE, and PSE) have to follow the RC and/or TOP directives.
Wolverine Power Supply Cooperative, Inc.		Wolverine agrees with the list of requirements that the trade associations are submitting. We are a member of NRECA and agree with their comments.

4. If you have any other comments or suggestions on the draft SAR that you have not already provided in response to the previous questions, please provide them here.

Summary Consideration:

Comment

NERC staff requests that the scope of the SAR include currently-pending versions of related Reliability Standards to address requirements proposed in Phase I that are also included in a subsequent version of the standard that has been adopted by the NERC Board of Trustees, but not yet approved by FERC. Manitoba Hydro has a similar concern. NERC staff also requests that technical justifications only rely on Commission-approved Reliability Standards and how removal of a requirement will "increase in efficiency of the ERO compliance program" consistent with the language of P81.

Response

The P81 SDT added a footnote to the SAR to address how pending versions of related Reliability Standards (i.e., NERC BOT adopted) are considered so that eliminated requirements carry through to any new NERC BOT adopted versions. In addition, the P81 SDT is developing a technical white paper that it believes will provide a sound, technical basis for removal of each NERC Reliability Standard requirement proposed in Phase I. As appropriate, the technical basis will only reference or rely on Commission-approved Reliability Standards. The technical white paper being developed by the P81 SDT will generally address the issue of efficiency gains in the ERO compliance program with a blanket statement, on a requirement basis, or a combination of both.

Comment

Kansas City Power & Light states that the retirement of the requirements should not have a ripple impact in other standards or requirements.

Response

Although it is unclear to the P81 SDT what is meant by the term "ripple impact," it is believed to be similar to Criterion C's defense in depth concept. In the future, it would be helpful to provide some examples where the removal of a NERC Reliability Standard requirement may have a ripple impact in other standards. At this time, the P81 SDT believes the consideration of Criterion C (specifically, the consideration of whether retiring a requirement will have any negative impact on the defense-in-depth protection of the BES) ensures that other standards and requirements are not negatively impacted.

Comment

Entergy Services, Inc. states that during future phases industry input should be gathered in a more formal process. PPL Corporation NERC Registered Affiliates had a similar suggestion to increase stakeholder involvement.

Response

The P81 SDT is using the approved Standard Process Manual (SPM) for Phase I, and, at this point, plans to use the SPM in effect at the time for future phases of this project as well. The SDT acknowledges that stakeholder input may need to be gathered in a manner differently in subsequent phases than that used for Phase I, as subsequent phases may be more involved than simply removing requirements in their entirety and will likely require combining and/or re-wording of existing requirements.

Comment

Dominion observed some highlighting and number issues in the draft documents and appears to suggest we add IRO-001-1a R8.

Response

Requirement 8 of NERC Reliability Standard IRO-001-1a, while redundant to TOP-001-1a R3 with regard to Reliability Coordinators, will need to remain to ensure that a NERC Reliability Standard exists that addresses the need for entities to comply with a Reliability Coordinator's Reliability Directives.

Typographical errors will be addressed by the SDT.

The spreadsheet with proposed retirements on the NERC website will be manually sorted to ensure appropriate ordering of requirements on future revisions.

Comment

South Carolina Electric and Gas states that instead of retiring R2 of EOP-009-0 could the whole standard can be replaced by the new EOP-005?

Response

Yes, it is the SDT's understanding that NERC Reliability Standard EOP-009-0 will be retired when Standard EOP-005-2 becomes enforceable (July 1, 2013).

Comment

Idaho Power Company, among other things, suggests the combing of MOD standards 016 through 021.

Response

The suggested combining of NERC Reliability Standards MOD-016 through MOD-021 has been referred to the Question 3 sub-team for consideration for Phase II.

Comment

ACES Power Marketing Standards Collaborators and Electric Reliability Council of Texas, Inc. state that NERC needs to develop guidance that includes these criteria for drafting teams to avoid developing requirements that offer little reliability value in the future.

Response

The P81 SDT agrees that NERC-developed guidance is needed for standard drafting teams to ensure that new requirements consider the criteria established by the P81 SDT. The P81 SDT will address this issue with the NERC Standards Committee.

Comment

Georgia System Operations Corporation and Georgia Transmission Corporation suggest the consideration of requirements for retirement that supports NERC programs other than the mandatory Reliability Standards.

Response

The SDT appreciates the comments. The SDT believes that the criteria, as drafted, should capture those requirements that Georgia System Operations Corporation and Georgia Transmission Corporation are concerned about.

Organization	Yes or No	Question 4 Comment
NERC Staff Technical Review		(1) NERC Staff notes that the scope of the SAR should be expanded to include currently-pending versions of related Reliability Standards to address requirements proposed in Phase I that are also included in a subsequent version of the standard that has been adopted by the NERC Board of Trustees, but not yet approved by FERC. NERC Staff suggests that footnotes could be included to capture these situations.(2) NERC Staff submits that the technical justification for removal of particular requirements should not be a restatement of the Criteria (see e.g., INT-007-1 R1.2). Nor should the technical justifications reference and/or rely upon for support any Reliability Standards unless those Reliability Standards are Commission-approved. (3) NERC Staff suggests that the technical justifications for the satisfaction of the Criteria

Organization	Yes or No	Question 4 Comment
		should include an explanation of how removal of the requirement will result in an "increase in efficiency of the ERO compliance program" consistent with the language of P81.
Duke Energy		Duke Energy generally supports the comments submitted by The Edison Electric Institute (EEI) and the process being used to respond to the Commission's invitation in the FFT Order.
Kansas City Power & Light		Efforts need to be made to make sure that the retirement of the requirements listed in "Proposed Requirements for Retirement in Phase 1 of Project 2013-02: Paragraph 81" don't have a ripple impact in other standards or requirements.
Entergy Services, Inc.		For future phases, indutry input should be gathered in a more formal process to allow for suggestions for re-wording or suggesting additional requirements for removal.
Tucson Electric Power		I appreciate the fact that there is a review of the NERC Standards as well as a review of the absolute need for various Standards and/or requirements. I also appreciate that the regulatory bodies are agreeable to such changes and improvements to the compliance process.
Illinois Municipal Electric Agency		Illinois Municipal Electric Agency fully supports this initiative by the collaboration group which suppports NERC's application of a risk-based focus to it's programs, and which is consistent with SPIG Recommendation 4.
Dominion		In the Complete Set of Standards with Proposed Retirements for Phase 1 pdf; Need to add IRO-001-1a R8 and MOD-004-1 R8 needs to be completely highlighted. In the Spreadsheet with Proposed Retirements; Suggest the MOD-004-1 Requirements be put in numeric order. Need to add IRO-001-1a R8; it is not listed on the spreadsheet.
South Carolina Electric and Gas		Instead of retiring R2 of EOP-009-0 could the whole standard can be replaced by the new EOP-005?

Organization	Yes or No	Question 4 Comment
Manitoba Hydro		It is not clear what will happen in instances where this project proposes to remove a requirement from a FERC approved Reliability Standard when the NERC BOT has already approved a newer version of that same standard. Will the newer BOT approved version also be modified if it includes one of the requirements in question? What if industry has already resolved one of these issues in the next version of a standard? Shouldn't we just implement the newer version?
MidAmerican Energy Company		MidAmerican Energy Company supports the draft SAR as a positive step to allow Responsible Entities, Regional Entities, NERC and FERC to focus their combined efforts on protecting the Bulk Electric System.
Idaho Power Company		MOD standards 016 through 021 should be combined into a single standard, removing duplication and retiring requirements which are "reporting-only" and/or have little discernable reliability benefit.We agree with the stated Purpose or Goal of the proposed standard of setting forth specific Reliability Standard requirement evaluation criteria and establishing a multi-phased process for addressing these Reliability Standard requirements. We agree with and support this Reliability Standard requirement evaluation and proposed multi-phased process based on the following:We believe there is value in differentiation of violations based on risk. We believe that not all violations pose the same risk to reliability, so they should not all be treated the same. Focusing on the greatest risks to reliability will allow for more efficient use of resources while improving the reliability of the BES through an application of structured risk management.
ACES Power Marketing Standards Collaborators		NERC needs to develop guidance that includes these criteria for drafting teams to avoid developing requirements that offer little reliability value in the future. There are many standards currently being developed that include similar kinds of requirements that will make a future exercise like this necessary. NERC should expend every effort to avoid such a future situation. Some examples can be found in Project 2007-09 Generator Verification. Proposed MOD-027-1 R3 through R5 largely

Organization	Yes or No	Question 4 Comment
		memorializes the administrative interactions that must occur between the GO and TP to develop a good active power/frequency control model. PRC-004-3 Part 4.2 in Project 2010-05.1 Misoperations is another example. It requires maintenance of data regarding Corrective Action Plans. These are administrative requirements and are unnecessary.
CPS Energy		No additional comments.
Independent Electricity System Operator		No comments.
Occidental Energy Ventures Corp.		OEVC Agrees with the Trade Associations on this response.
Pepco Holdings Inc & Affiliates		Pepco Holdings Inc supports this project. Additionallyl Pepco Holdings Inc supports the comments provided by EEI.
Georgia System Operations Corporation		Reliability Standard requirements are those that provide for Reliable Operation, including without limiting the foregoing, requirements for the operation of existing Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation. NERC administers other programs, such as industry alerts, reliability assessments, event and trend analyses, education, and monitoring and enforcing Reliability Standards. These other programs are designed to work in concert with Reliability Standards to support reliable operation. NERC requirements relating to administering these other programs are very important but are not Reliability Standard requirements.One of the criteria for evaluating the elimination of a Reliability Standard requirement is that it is purely reporting. There are a number of NERC requirements for these other NERC programs embedded in Reliability Standards. Most of them are purely reporting. However, to the extent that there may be other requirements for these NERC programs embedded that are not purely

Organization	Yes or No	Question 4 Comment
		reporting, they should also be considered for elimination. Reliability Standards by definition are not mechanisms for the administration of those other NERC programs.
Georgia Transmission Corporation		Reliability Standard requirements are those that provide for Reliable Operation, including without limiting the foregoing, requirements for the operation of existing Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation. NERC administers other programs, such as industry alerts, reliability assessments, event and trend analyses, education, and monitoring and enforcing Reliability Standards. These other programs are designed to work in concert with Reliability Standards to support reliable operation. NERC requirements relating to administering these other programs are very important but are not Reliability Standard requirements.One of the criteria for evaluating the elimination of a Reliability Standard requirement is that it is purely reporting. There are a number of NERC requirements for these other NERC programs embedded in Reliability Standards. Most of them are purely reporting. However, to the extent that there may be other requirements for these NERC programs embedded that are not purely reporting, they should also be considered for elimination. Reliability Standards by definition are not mechanisms for the administration of those other NERC programs. GTC recommends identifying these requirements (ex. MOD-016 through 021) and appending them to the Phase I list.
seattle city light		Seattle City Light supports the consolidated comments of the industry Trade Organizations.
Tampa Electric Company		Tampa Electric recommends that the P81 DT ensure that the CIP requirements proposed for removal via P81 are also removed from v5 of the NERC CIP standards. Tampa Electric also supports the consideration of the following for NERC CIP standards: Removal of data collection requirements: CIP-005-3a, -4a R5.3CIP-006c, -4c R7, R8.3CIP-007-3, -4 R5.1.2; R6.4; R7.3CIP-008-3, -4 R2Removal of annual review requirements: CIP-002-2, -4 R4CIP-003-3, -4 R1.3; CIP-003-3, -4 R4.3; CIP-003-3, - 4

Organization	Yes or No	Question 4 Comment
		R5.1.2; CIP-003-3, - 4 R5.3CIP-006-3c, -4 R1.8CIP-007-3, -4 R9CIP-009-3, -4 R1
Transmission Agency of Northern California		TANC commends FERC for soliciting input on ways to eliminate requirements that are redundant or provide little protection for the bulk power system. TANC believes that NERC has proposed an appropriate response to this opportunity and looks forward to further initiatives that prioritize reliability ahead of compliance.
SERC EC Planning Standards Subcommittee		The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
SPP Standards Review Group		The following are typos we found in the SAR:Either delete the 'an' or make 'processes' singular in Technical Criteria B.2.(b).Either delete the 'that' in the 5th line or the 'to' in the 6th line of the Statement paragraph under CIP-001-2a R4. This is the 3rd sentence in the paragraph.Insert an 'a' between 'require' and 'new' in the last sentence of the Statement paragraph under CIP-003-3, -4 R4.2.
City of Austin dba Austin Energy		The P81 project should be considered a high priority Standards development project for the following reasons:(1) Responsive to P81 of FERC's March 15, 2012 order and SPIG Recommendation No. 4(2) Will increase efficiency of the ERO compliance programs(3) Requirements submitted for the initial phase appear to be clear candidates on their face and should not require extensive technical research(4) The collaborative nature of the project is an example for future work, because it advances the project while reducing the impact on stakeholders and NERC staff(5) The proposed pace of the project sets an example for future work (6) Furthers the focus on results, performance based Reliability Standards (7) May provide a roadmap of what should or should not be a requirement in future Reliability Standards(8) The draft P81 SAR criteria is designed to be sufficiently broad to capture all FERC approved reliability Standards that are unnecessary, redundant or do little to protect reliability (9) To eliminate Reliability Standards requirements that deter from our

Organization	Yes or No	Question 4 Comment
		focus on reliability Based on these benefits, we support the Standards Drafting Team and NERC staff working together to file the initial list of Reliability Standards for retirement with the Federal Energy Regulatory Commission prior to the end of the year and that the Standards Drafting Team also make significant progress on the scope of the phase two P81 Reliability Standards list by the end of the year.
PPL Corporation NERC Registered Affiliates		The PPL Companies generally support the concept and process being recommended, but are concerned that the stakeholder involvement in the process may be lacking. During the webinar on August 21, 2012 the drafting team members stated that the Standards Development Process will be utilized for all Phases of the project. However, the SAR does not indicate that the SDP is mandated. The Companies recommend that the entire SAR specifically state the the Standards Development Process will be used where the SDT must respond to comments and a stakeholder vote for approval. Additionally, the process should allow for individual (or groups) of stakeholders to request a standard's removal or modification that is not designated by the SDT for removal.
The Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), the Electric Power Supply Association (EPSA), the Transmission Access Policy Study Group (TAPS), Electricity Consumers Resource Council (ELCON), the American Public Power Association (APPA), the Large Public Power Council (LPPC) and, the Canadian Electricity Association (CEA) (collectively, the Trade		The Trade Associations believe that the P81 project should be considered a high priority Standards development project for the following reasons: o Responsive to P81 of FERC's March 15, 2012 order and SPIG Recommendation No. 4 o Will increase efficiency of the ERO compliance programs o Requirements submitted for the initial phase appear to be clear candidates on their face and should not require extensive technical research o The collaborative nature of the project is an example for future work, because it advances the project while reducing the impact on stakeholders and NERC staff o The proposed pace of the project sets an example for future work o Furthers the focus on results, performance based Reliability Standards o May provide a roadmap of what should or should not be a requirement in future Reliability Standards o The draft P81 SAR criteria are designed to be sufficiently broad to capture all FERC approved reliability Standards that are unnecessary, redundant or do little to protect reliability o Eliminating Reliability Standards requirements that are unnecessary, redundant or do little to protect reliability will

Organization	Yes or No	Question 4 Comment
Associations).		eliminate distractions from our focus on reliability Based on these benefits, the Trade Associations strongly support the Standards Drafting Team and NERC staff working together to file the initial list of Reliability Standards for retirement with the Federal Energy Regulatory Commission prior to the end of the year, and that the Standards Drafting Team also make significant progress on the scope of the phase two P81 Reliability Standards list by the end of the year.
City of Garland		This is a good start on removing requirements that are either redundant or provide little / no protection for Bulk-Power System reliability.
Electric Reliability Council of Texas, Inc.		This SAR offers significant potential value by retiring requirements that provide no BES reliability value, but nonetheless require commitment of time and resources for both regulated entities and regulators to effect and oversee compliance, respectively, and also pose liability risk for no reason, given that they provide no reliability value. However, the substance of the requirements (e.g. administrative processes, etc.) may have non-essential value unrelated to system reliability. To the extent the SDT/industry/NERC believe there may be some non-mandatory use for this information outside of the reliability standards, the information could be considered for guidance in another format, such as guidelines, best practice documentation or lessons learned. If such an effort is deemed worthwhile, it should be established in a separate process/effort, and should not distract from moving this and future phases of this SAR forward in the most efficient and effective manner to achieve the significant benefits that may result from this SAR. In addition, the standards process going forward should include consideration of whether a proposed standard addresses a reliability requirement, is cost effective and meets the reliability-based standards criteria of “what” needs to be met and not “how” an entity will meet the standard which is better address through guidelines, best practices and/or lessons learned.
Central Husdon Gas & Electric		We agree with the criteria as listed, however, we believe that another criterion must be added. This criterion is that the retirement of a requirement must not create a

Organization	Yes or No	Question 4 Comment
Corporation		compliance gap for Entities. Several of the NERC requirements have been crafted to afford Entities a means to display compliance. Retirement of these requirements can place an Entity's compliance efforts in jeopardy. A salient example of this is identified below:Central Hudson Gas & Electric Corporation strongly disagrees with the inclusion of CIP-003-3, -4 Requirements R3, R3.1, R3.2, R3.3 as candidates for retirement. The reasons stated in the SAR in favor of inclusion are that these requirements are administrative in nature and are purely examples of a documentation process. Further it is stated in the SAR that they, ".... have been subject to misinterpretation, including responsible entities believing they can exempt themselves from compliance with the CIP requirements." This last statement is precisely the reason why the aforementioned requirements were included in the standard. These requirements allow Registered Entities to, on rare occasions, take an exception to one or several of the CIP requirements (for a limited period of time) if they (1) have valid cause (major emergency, Force Majeure, etc.), (2) document the occurrence and (3) are reviewed and approved by the CIP Senior Manager. This process supports the Registered Entity's compliance effort and acknowledges the need for special protocols to address emergency circumstances. Without such a process, the only recourse for the Registered Entity is to self-report a violation which is not within its control. In other words, retirement of these requirements would force the Registered Entity to be in full compliance with ALL CIP Standards ALL the time regardless of circumstance. The concept of 'realistic expectation' was undoubtedly the reason these requirements were crafted and included in the standard. Further, with regard to the Registered Entity's decision to claim an exception, a system of checks and balances already exists. At the time of a compliance audit of the standard's requirements, the Regional Entity reviews and makes a determination as to whether the actions taken by the Registered Entity were warranted.
NV Energy		We commend NERC and the Drafting Team on their efforts thus far in this important initiative. This process will serve to better focus the industry's limited resources on

Organization	Yes or No	Question 4 Comment
		activities that are necessary for reliability.
SRC		We support the P81 team's efforts and appreciate the effort to pull together this initial list of criteria and requirements. The SRC is looking forward to seeing a concrete timeline for the project.
Western Electricity Coordinating Council		WECC recognizes and appreciates the large amount of work done in a short time on this project and appreciates the opportunity to proved our comments.
American Electric Power		While AEP supports the efforts of this drafting team, it might have been advantageous to first agree on the criteria as a first phase, and then once determined, enter a second phase where requirements were proposed based upon the agreed-upon criteria. This might enable the fast-tracking of the criteria to be used by other concurrent projects and project teams.

END OF REPORT

P81 Project Technical White Paper

October 23, 2012

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P81 Project Technical White Paper

October 23, 2012

I. Introduction

On March 15, 2012, the Federal Energy Regulatory Commission ("FERC" or Commission") issued an order[1] on the North American Electric Reliability Corporation's ("NERC") Find, Fix and Track ("FFT") process that stated in paragraph 81 ("P81"):

> The Commission notes that NERC's FFT initiative is predicated on the view that many violations of requirements currently included in Reliability Standards pose lesser risk to the Bulk-Power System. If so, some current requirements likely provide little protection for Bulk-Power System reliability or may be redundant. The Commission is interested in obtaining views on whether such requirements could be removed from the Reliability Standards with little effect on reliability and an increase in efficiency of the [Electric Reliability Organization] ERO compliance program. If NERC believes that specific Reliability Standards or specific requirements within certain Standards should be revised or removed, we invite NERC to make specific proposals to the Commission identifying the Standards or requirements and setting forth in detail the technical basis for its belief. In addition, or in the alternative, we invite NERC, the Regional Entities and other interested entities to propose appropriate mechanisms to identify and remove from the Commission-approved Reliability Standards unnecessary or redundant requirements. We will not impose a deadline on when these comments should be submitted, but ask that to the extent such comments are submitted NERC, the Regional Entities, and interested entities coordinate to submit their respective comments concurrently.

A. Consensus Process

In response to P81 and the Commission's request for comments to be coordinated,[2] during June and July 2012, various industry stakeholders, Trade Associations,[3] staff from NERC and staff from the NERC Regions jointly discussed consensus criteria and an initial list of Reliability Standard requirements that appeared to easily satisfy the criteria, and, thus, could be retired. Specifically, the three parties (industry stakeholders/Trade Associations, staff from NERC, and staff from the NERC Regions) used the following

[1] *North American Electric Reliability Corporation,* 138 FERC ¶ 61,193 at P 81 (2012).

[2] In addition to addressing P81, the consensus effort was also consistent with recommendation #4 set forth in *NERC's Recommendations to Improve The Standards Development Process* at page 12 (April 2012), which states:

Recommendation 4: Standards Product Issues — The NERC board is encouraged to require that the standards development process address: . . . The retirement of standards no longer needed to meet an adequate level of reliability.

[3] Edison Electric Institute, American Public Power Association, National Rural Electric Cooperative Association, Large Public Power Council, Electricity Consumers Resource Council, The Electric Power Supply Association, and Transmission Access Policy Study Group.

conservative discipline to arrive at the proposed list of requirements to be retired: (i) the development of criteria to determine whether a Reliability Standard requirement should be retired and (ii) the application of this criteria with consultation from Subject Matter Experts ("SME"), with the understanding that if any of the three parties objected to including a requirement it would not be included in the initial phase of the P81 Project. As a result of this process, a draft Standards Authorization Request ("SAR"), including an initial suggested list of requirements for retirement, was drafted and presented to the NERC Standards Committee. Also, the SMEs consulted in this process provided the technical justifications that appear in this technical white paper.

B. Standards Committee

On July 11, 2012, the Standards Committee authorized the draft SAR to be posted for industry comment and formed an interim P81 Standards Drafting Team ("SDT") to review and respond to comments as well as finalize the SAR. The draft SAR was posted on August 3, 2012 with stakeholder comments due on or before September 4, 2012. Based on the stakeholder comments received, the SDT finalized the SAR, including the criteria and the initial list of Reliability Standard requirements proposed for retirement. On September 28, 2012, the Standards Committee Executive Committee authorized: (a) waiving the 30 day initial comment period and (b) posting the SAR and list of requirements proposed for retirement in the initial phase for a 45-day formal comment period with the formation of a ballot pool during the first 30 days and an initial ballot during the last 10 days of that 45-day comment period.[4]

The purpose of this technical white paper is to set forth the background and technical justification for each of the Reliability Standard requirements proposed for retirement. Stakeholders are requested to review this technical white paper and provide the SDT any: (1) supplemental, additional technical justifications for a requirement(s) and/or (2) concerns with the technical justifications for a requirement(s).

[4] The following requirements that were presented in the draft SAR were already scheduled to be retired or subsumed via another Standards Development Project that has been approved by stakeholders and the NERC Board of Trustees (or due to be before the Board in November), and, thus, are presented in this technical white paper in Section V for informational purposes only: COM-001-1.1 R6; EOP-009-0 R2; FAC-008-1 R1.3.5; PRC-008-0 R1; PRC-008-0 R2; PRC-009-0 R1; PRC-009-0 R1.1; PRC-009-0 R1.2; PRC-009-0 R1.3; PRC-009-0 R1.4; PRC-009-0 R2; TOP-001-1a R3; and TOP-005-2a R1. For regulatory efficiency, these requirements will not be presented for comment and vote, and, therefore, will not be presented to the Board of Trustees for retirement or filed with the Commission or Canadian governmental authorities as part of the P81 Project. Those requirements that were not part of the draft SAR, but were added based on stakeholder comments are denoted by a "**" throughout this technical white paper. More detail on each of these requirements is provided below.

II. Executive Summary

The SDT developed a set of three criteria and used them to identify requirements that could be eligible for retirement. A summary of the criteria are as follows:

A. Criterion A (Overarching Criterion): little, if any, benefit or protection to the reliable operation of the BES

B. Criteria B (Identifying Criteria)
   - B1. Administrative
   - B2. Data Collection/Data Retention
   - B3. Documentation
   - B4. Reporting
   - B5. Periodic Updates
   - B6. Commercial or Business Practice
   - B7. Redundant

C. Criteria C (Additional data and reference points)
   - C1. Part of a FFT filing
   - C2. Being reviewed in an ongoing Standards Development Project
   - C3. Violation Risk Factor ("VRF") of the requirement
   - C4. Tier in the 2013 Actively Monitored List ("AML")
   - C5. Negative impact on NERC's reliability principles
   - C6. Negative impact on the defense in depth protection of the BES
   - C7. Promotion of results or performance based Reliability Standards

Specifically, for a requirement to be proposed for retirement, it must satisfy both, Criterion A and at least one of the Criteria B. Criteria C were considered as additional information to make a more informed decision.

Based on the criteria above, the SDT proposes to retire the following 38 requirements in 23 Reliability Standard versions:

- BAL-005-0.2b R2
- CIP-001-2a R4
- CIP-003-3 R1.2
- CIP-003-3 R3
- CIP-003-3 R3.1
- CIP-003-3 R3.2
- CIP-003-3 R3.3
- CIP-003-3 R4.2
- CIP-003-4 R1.2
- CIP-003-4 R3
- CIP-003-4 R3.1
- CIP-003-4 R3.2

- CIP-003-4 R3.3
- CIP-003-4 R4.2
- CIP-005-3a R2.6
- CIP-005-4a R2.6
- CIP-007-3 R7.3
- CIP-007-4 R7.3
- EOP-004-1 R1
- EOP-005-2 R3.1
- FAC-002-1 R2
- FAC-008-1 R2
- FAC-008-1 R3
- FAC-008-3 R4
- FAC-008-3 R5
- FAC-010-2.1 R5**
- FAC-011-2 R5**
- FAC-013-2 R3
- INT-007-1 R1.2
- IRO-016-1 R2
- NUC-001-2 R9.1
- NUC-001-2 R9.1.1
- NUC-001-2 R9.1.2
- NUC-001-2 R9.1.3
- NUC-001-2 R9.1.4
- PRC-010-0 R2
- PRC-022-1 R2
- VAR-001-2 R5**

A table is included in Appendix A with the Reliability Standard requirements proposed for retirement and a cross-reference to the associated criteria.

III. Criteria

The P81 Project focuses on identifying FERC-approved Reliability Standard requirements that satisfy the criteria set forth below.[5] Specifically, for a Reliability Standard requirement to be proposed for retirement it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). The purpose of having these two levels of criteria was to confine the review and consideration of requirements to only those requirements that clearly need not be included in the mandatory Reliability Standards. Also, Criteria A and B were designed

[5] The scope of future phases of the P81 Project has not yet been determined. When the scope is considered, the criteria set forth herein may be a useful guide to appropriate criteria for those phases.

so there would be no rewriting or consolidation of requirements, and the technical merits of retiring the requirements did not require significant research and vetting. In addition, for each Reliability Standard requirement proposed for retirement, the data and reference points set forth below in Criteria C were considered to make a more informed decision on whether to proceed with retirement. Lastly, for each requirement proposed for retirement, any increase to the efficiency of the ERO compliance program is addressed.

Criterion A (Overarching Criterion)
The Reliability Standard requirement requires responsible entities to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)
B1. Administrative
The Reliability Standard requirement requires responsible entities ("entities") to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be removed with little effect on reliability and whose removal will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is or is not related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be removed with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be eliminated in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.*, plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.*, annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program or (iii) a governmental regulation (*e.g.*, Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be removed with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
In those instances where there is a need for additional information to assist in the determination of whether a Reliability Standard requirement satisfies both Criteria A and B, the following data and reference points shall be considered to make a more informed decision:

C1. Was the Reliability Standard requirement part of a FFT filing?

The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an on-going Standards Development Project?

The application of this criterion involves determining whether the requirement proposed for retirement is part of an active on-going Standards Development Project, with a consideration of the point in the process that Project is at. If the requirement has been passed by the stakeholders and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not be included in the P81 project to promote regulatory efficiency. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time; or, other requirements that based on the specific facts and circumstances of that requirement indicate it should be retired via the P81 Project first rather than waiting for another Standards Development Project to retire it, particularly as a way to increase the efficiencies of the ERO compliance program. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project will be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?

The application of this criterion involves identifying the VRF of the requirement proposed for retirement, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that it qualifies for retirement. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired if its retirement harms the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the 2013 AML does the Reliability Standard requirement fall?

The application of this criterion involves identifying whether the requirement proposed for retirement is on the 2013 AML, with particular consideration for any requirement in the first tier of the 2013 AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?

The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

> **Reliability Principles**
> NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.
>
> Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
>
> Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
>
> Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
>
> Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?

The application of this criterion considers whether the requirement proposed for retirement is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement to protect the BES.

C7. Does the retirement promote results or performance based Reliability Standards?

The application of this criterion considers whether the requirement, if retired, will promote the initiative to implement results- and/or performance-based Reliability Standards.

IV. The Initial Phase Reliability Standards Requirements Proposed for Retirement

The following lists the requirements proposed for retirement with details of the assessment resulting from the applicability of the criteria above.

BAL-005-0.2b R2 – Automatic Generation Control

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

Background/Commission Directives

BAL-005-0 was filed for Commission approval on April 4, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[6] Also, the Commission accepted an errata filing to BAL-005-0.1b, which replaced Appendix 1 with a corrected version of a Commission-approved interpretation, and made an internal reference correction in the interpretation, thus resulting in BAL-005-0.2b.[7]

In Order No. 693 at paragraph 387, the Commission stated that:

> The goal of this Reliability Standard is to maintain Interconnection frequency by requiring that all generation, transmission, and customer load be within the metered boundaries of a balancing authority area, and establishing the functional requirements for the balancing authority's regulation service, including its calculation of ACE.

At paragraph 396, the Commission stated:

> On this issue, the Commission directs the ERO to modify BAL-005-0 through the Reliability Standards development process to develop a process to calculate the minimum regulating reserve for a balancing authority, taking into account expected load and generation variation and transactions being ramped into or out of the balancing authority.

This Commission directive is unaffected by the proposed retirement of BAL-005-0.2b R2.

Additionally, when adjusting the VRF for the previous version, BAL-005-0.1b R2, from Lower to High, the Commission stated that:[8]

> While theoretically, CPS can be met without the use of AGC, for example, when the AGC system is malfunctioning, the Commission believes, in practice, that AGC is the most dependable and effective means for multiple balancing authorities in an Interconnection to collectively meet CPS requirements in tandem while minimizing assistance from each other in this regard. Human reaction is neither fast enough nor dependable enough in this repetitive task to provide the immediate and continuous support to correct for Interconnection frequency drift. Further, the failure to use AGC presents a higher risk that immediate load shedding will need to be implemented after the sudden loss of generation or an unforeseen

[6] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[7] Letter Order, Petition of the North American Electric Reliability Corporation for Approval of Errata Changes to Seven Reliability Standards, Docket No. RD12-4-000 (September 13, 2012).

[8] *North American Electric Reliability Corporation*, 121 FERC ¶ 61,179 at P 50 (2007).

> significant load increase and, thus, the failure to use AGC subjects the Bulk-Power System to a higher risk of instability.

However, the fact that the VRF for BAL-005-0.2b R2 is High is not indicative of its actual impact on the BES as explained in further detail below. Also, no Commission directive is impacted by BAL-005-0.2b R2.

Technical Justification

The stated reliability purpose of BAL-005-0.2b is to establish requirements for Balancing Authority Automatic Generation Control ("AGC") necessary to calculate Area Control Error ("ACE") and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. The reliability purpose and objectives of BAL-005-0.2b are unaffected by the proposed retirement of R2.

A Balancing Authority must use AGC to control its Regulating Reserves to meet the Control Performance Standards ("CPS") as set forth in BAL-001-0.1a R1 and R2. Although for a short period of time (as the Commission stated during an AGC malfunction) a Balancing Authority may be able to meet its CPS obligations without AGC, it cannot do so for any extended period of time, and, therefore, Balancing Authorities must use AGC to control its Regulating Reserves to satisfy its obligations under BAL-001-0.1a R1 and R2. Given this fact, it is redundant to also have BAL-005-0.2b R2 set forth the following statement: "Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard." (Criterion B7). It is the duplicative nature of having two requirements requiring the same activity that does little, if anything, to benefit or protect reliable operation of the BES. (Criterion A). In other words, without the existence of BAL-005-0.2b R2, Balancing Authorities must still have Regulating Reserves that can be controlled by AGC to satisfy the CPS in BAL-001-0.1a R1 and R2.

Also, the retirement of BAL-005-0.2b R2 would increase the efficiency of the ERO compliance program because NERC and the Regional Entities would be able to focus their time and resources on monitoring compliance on BAL-001-0.1a R1 and R2, which are results-based requirements, versus monitoring compliance with both BAL-001-0.1a R1 and R2 as well as the static statement in BAL-005-0.2b R2. Therefore, retiring BAL-005-0.2b R2 will provide for increased efficiencies in the ERO compliance program.

Criterion A

Without the existence of BAL-005-0.2b R2, Balancing Authorities must still have Regulating Reserves that can be controlled by AGC to satisfy the CPS in BAL-001-0.1a R1 and R2. Having two requirements requiring a Balancing Authority to conduct the same activity or task does little, if anything, to benefit or protect the reliable operation of the BES because it is duplicative.

Criteria B

- Criterion B7 (Redundant)

Criteria C

1. BAL-005-0.2b R2 has not been part of a FFT filing.

2. BAL-005-0.2b R2 is currently scheduled to be included in Standards Development Project 2010-14.2, which is Phase II of Balancing Authority Reliability-based Controls: Time Error, AGC, and Inadvertent. Given that Project 2010-14.2 is currently not an active Standards Development Project, it remains appropriate to retire BAL-005-0.2b R2 via the P81 Project.

3. The VRF for BAL-005-0.2b R2 is High. Given the redundant nature of BAL-005-0.2b R2, the High VRF is not dispositive of whether or not it should be retired since BAL-001-0.1a R1 and R2 accomplishes the important reliability requirement of Balancing Authorities maintaining Regulating Reserves that can be controlled by AGC to satisfy CPS.

4. BAL-005-0.2b R2 is not part of the 2013 AML.

5. The redundant nature of BAL-005-0.2b R2 with BAL-001-0.1a R1 and R2 also indicates that the retirement of BAL-005-0.2b R2 does not pose a negative impact to NERC's published and posted reliability principles. The two reliability principles applicable to BAL-005-0.2b R2 are the following:

    Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

    Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

6. Retirement of BAL-005-0.2b R2 does not negatively impact defense in depth because no other requirement depends on it to help cover a reliability gap or risk to reliability. As discussed above, given that BAL-001-0.1a R1 and R2 already require that AGC be used to control Regulating Reserves, there is no risk or gap to reliability resulting from the retirement of BAL-005-0.2b R2.

7. Retirement of BAL-005-0.2b R2 promotes a results-based approach, because it is retiring a static requirement while BAL-001.1a R1 and R2, which are more dynamic and results-based requirements, will remain in effect.

Accordingly, for the above reasons, it is appropriate to retire BAL-005-0.2b R2.

CIP-001-2a R4 Sabotage Reporting

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.

Background/Commission Directives

CIP-001-1 was filed for Commission approval on November 15, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[9] CIP-001-1a was filed for Commission approval on April 21, 2010 in Docket No. RD10-11-000, and was approved by an unpublished letter order on February 2, 2011.[10]

CIP-001-2a was filed for Commission approval as a Regional Variance for the ERCOT Region, containing an interpretation of CIP-001-1, on June 21, 2011 in Docket No. RD11-6-000 and was approved by unpublished letter order on August 2, 2011.[11]

In Order No. 693 at paragraph 460, the Commission stated:

> For these reasons, the Commission remains concerned that a wider application of CIP-001-1 may be appropriate for Bulk-Power System reliability. Balancing these concerns with our earlier discussion of the applicability of Reliability Standards to smaller entities, we will not direct the ERO to make any specific modification to CIP-001-1 to address applicability. However, we direct the ERO, as part of its Work Plan, to consider in the Reliability Standards development process, possible revisions to CIP-001-1 that address our concerns regarding the need for wider application of the Reliability Standard. Further, when addressing such applicability issues, the ERO should consider whether separate, less burdensome requirements for smaller entities may be appropriate to address these concerns.

In Order No. 693 at paragraphs 445 and 467 through 470, the Commission stated that:

> The goal of CIP-001-1 is to ensure that operating entities recognize sabotage events and inform appropriate authorities and each other to

[9] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[10] Letter Order, Petition of the North American Electric Reliability Corporation for Approval of Interpretation to Reliability Standard CIP-001-1 —Cyber Security— Sabotage Reporting, Requirement R2, Docket No. RD10-11-000 (February 2, 2011).
[11] Letter Order, Petition of the North American Electric Reliability Corporation for Approval of the Reliability Standard CIP-001-2a – Sabotage Reporting with a Regional Variance for Texas Reliability Entity, Docket No. RD11-6-000 (August 2, 2011).

properly respond to the sabotage to minimize the impact on the Bulk-Power System. The Reliability Standard requires that each reliability coordinator, balancing authority, transmission operator, generation operator and LSE have procedures for recognizing and for making operating personnel aware of sabotage events, and communicating information concerning sabotage events to appropriate "parties" in the Interconnection.

* * *

CIP-001-1, Requirement R4, requires that each applicable entity establish communications contacts, as applicable, with the local FBI or Royal Canadian Mounted Police officials and develop reporting procedures as appropriate to its circumstances. The Commission in the NOPR expressed concern that the Reliability Standard does not require an applicable entity to actually contact the appropriate governmental or regulatory body in the event of sabotage. Therefore, the Commission proposed that NERC modify the Reliability Standard to require an applicable entity to "contact appropriate federal authorities, such as the Department of Homeland Security, in the event of sabotage within a specified period of time."

As mentioned above, NERC and others object to the wording of the proposed directive as overly prescriptive and note that the reference to "appropriate federal authorities" fails to recognize the international application of the Reliability Standard. The example of the Department of Homeland Security as an "appropriate federal authority" was not intended to be an exclusive designation. Nonetheless, the Commission agrees that a reference to "federal authorities" could create confusion. Accordingly, we modify the direction in the NOPR and now direct the ERO to address our underlying concern regarding mandatory reporting of a sabotage event. The ERO's Reliability Standards development process should develop the language to implement this directive.

* * *

Thus, the Commission directs the ERO to modify CIP-001-1 to require an applicable entity to contact appropriate governmental authorities in the event of sabotage within a specified period of time, even if it is a preliminary report. The ERO, through its Reliability Standards development process, is directed to determine the proper reporting period. In doing so, the ERO should consider suggestions raised by commenters such as FirstEnergy and Xcel to define the specified period for reporting an incident beginning from when an event is discovered or suspected to be sabotage, and APPA's concerns regarding events at unstaffed or remote

> facilities, and triggering events occurring outside staffed hours at small entities. (Footnotes omitted).

The Commission's suggestion to modify CIP-001-1 to require an applicable entity to contact appropriate federal authorities, such as the Department of Homeland Security, is being considered in Standards Development Project 2009-01 (EOP-004-2). CIP-001-2a R4 is proposed for retirement because it does not require an action when sabotage is suspected or actually occurs, rather that action is addressed via CIP-001-2a R2.

Technical Justification

The practices and procedures set forth in CIP-001-2a R2 provides the results-based foundation for contacting communication of information concerning sabotage events to appropriate parties in the Interconnection, including when necessary, the FBI or RCMP, when there is an event of suspected or actual sabotage, while the task in R4 does little, if anything, to benefit or protect the reliable operation of the BES. (Criterion A). Consistent with CIP-001-2a R1 (identification of sabotage), R2 (communication of sabotage) and R3 (reporting of sabotage),[12] a responsible entity generally contacts local law enforcement authorities when there is any suspicion that sabotage has occurred at a BES facility. The entity's corporate security and site personnel will consult with local law enforcement to assess the situation and facts to determine whether a suspected or actual act of sabotage has occurred. If they find a suspected or actual act of sabotage has occurred, the FBI or RCMP, as appropriate, will be contacted in accordance with R2.[13] Thus, pursuant to the different steps and actions in R1 through R3, when there is an instance of sabotage that warrants contacting the FBI or RCMP or any other federal/national governmental authority, the responsible entities will contact them. Conversely, CIP-001-2a R4 does not require that the FBI or RCMP be contacted when an act of suspected or actual sabotage has occurred; instead, R4 only requires that the entity establish communication contacts with these agencies, as appropriate, and "develop reporting procedures. . . ." While the development of reporting procedures in R4 is generic, the procedures and processes associated with R1, R2, and R3 are specific to the steps of identifying, communicating and reporting issues related to sabotage. This view was confirmed in the interpretation of R2 that states:

> . . . the phrase "appropriate parties in the Interconnection" to refer collectively to entities with whom the reporting party has responsibilities and/or obligations for the communication of physical or cyber security event information.

[12] "**R2.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection."

[13] In addition, the requirement, as written, does not reflect current reporting and investigation procedures in some of the Canadian Provinces as protocol for sabotage reporting and investigation varies in each Canadian Province. For example, in the Provinces of Ontario and Quebec, the reports are given to local police (municipal/provincial) and not to the RCMP as the standard specifies. The fact is that the RCMP does not perform Provincial level law enforcement in the Provinces of Ontario and Quebec.

Consequently, the R4 requirement to establish communication contacts and develop reporting procedures does not support reliability, and, instead, is an administrative, documentation and data collection task requirement (Criteria B1, B2 and B3). Also, in the overall context of CIP-001-2a R1 through R3, which already require sabotage related procedures and guidelines, the tasks in R4 are unnecessary and needlessly burdensome. Furthermore, corporate security departments that are involved in the investigation of sabotage related events are well aware of how to contact the FBI and RCMP, as applicable, and, in fact, some corporate security employees to have a law enforcement background, including past positions in federal agencies such as the Secret Service. To have these security professionals establish contacts with agencies they are readily familiar with and to generic develop reporting procedures that do not require action is unnecessarily burdensome. The administrative aspect of R4 is further illuminated when compared to the more results-based activities in CIP-001-2a R1 through R3, which are the requirements that serve reliability by requiring action when suspected or actual sabotage occurs. Accordingly, CIP-001-2a R1 through R3 serve the results-based reliability function, while R4 is a static, administrative requirement that has no direct or clear nexus to protecting BES reliability.

Also, the retirement of CIP-001-2a R4 should increase the efficiencies of the ERO compliance program, because ERO and Regional Entity time and resources would be able to focus more attention, if needed, on monitoring compliance with CIP-001-2a R1 through R3.

Criterion A
CIP-001-2a R2 provides the results-based foundation for contacting communication of information concerning sabotage events to appropriate parties in the Interconnection, including when necessary, the FBI or RCMP, when there is an event of suspected or actual sabotage, while the task in R4 does little, if anything, to benefit or protect the reliable operation of the BES.

Criteria B
- Criterion B1 (Administrative)
- Criterion B2 (Data Collection/Data Retention)
- Criterion B3 (Documentation)

Criteria C
1. CIP-001-2a R4 has been part of a FFT filing.[14]

[14] NERC FFT Informational Filing, Docket No. RC12-15-000 (August 31, 2012); NERC FFT Informational Filing, Docket No. RC12-13-000 (June 29, 2012); NERC FFT Informational Filing, Docket No. RC12-11-000 (April 30, 2012); NERC FFT Informational Filing, Docket No. RC12-6-000 (December 30, 2011); NERC FFT Informational Filing, Docket No. RC12-2-000 (November 30, 2011); NERC FFT Informational Filing, Docket No. RC12-1-000 (October 31, 2011); NERC FFT Informational Filing, Docket No. RC11-6-000 (September 30, 2011).

2. CIP-001-2a R4 is part of an on-going Standards Development Project 2009-01 (EOP 004-2). At this time, EOP-004-2 has not been approved by stakeholders and the NERC Board of Trustees, and, therefore, it is appropriate to retain CIP-001-2a R4 within the scope of P81. However, if EOP-004-2 does receive stakeholder approval and is adopted by the NERC Board of Trustees, the SDT will reconsider retirement via the P81 Project and may include CIP-001-2a R4 for informational purposes only.

3. CIP-001-2a R4 has a Medium VRF. All of CIP-001-2a has a Medium VRF, thus the fact that R4 is a Medium VRF is not dispositive of whether it should be retired.

4. CIP-001-2a R4 is in the second tier of the AML. Similar to the VRF, having CIP-001-2a R4 in the second tier of the AML is not dispositive of whether it should be retired, particularly when considered with the fact that R2 and R3, the more results-based requirements, are in the first tier.

5. Given its lack of requiring a reliability based action, the retirement of CIP-001-2a R4 does not negatively impact NERC's published and posted reliability principles. The only principles applicable to CIP-001-2a R4 appear to be the following:

   Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

   Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks.

6. The retirement of CIP-001-2a R4 does not impact a defense in depth strategy between multiple requirements. CIP-001-2a R1 through R3 provide the foundation for the identification, communication and reporting of suspected and actual sabotage, while R4 is an administrative task of establishing contacts and developing generic reporting procedures. Therefore, there is no reliability risk or gap that will result from the retirement of CIP-001-2a R4.

7. As mentioned above, CIP-001-2a R4 is not a results-based requirement.

Accordingly, for the above reasons, it is appropriate to retire CIP-001-2a R4.

CIP-003-3, -4 R1.2 – Cyber Security – Security Management Controls

R1.2. The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.

Background/Commission Directives

CIP-003-1 was filed for Commission approval on August 28, 2006 in Docket No. RM06-16-000 and was approved on January 18, 2008 in Order No. 706.[15] CIP-003-2 was filed for Commission approval on May 22, 2009 in Docket Nos. RM06-22-000 and RD09-7-000 and was approved on September 30, 2009.[16] CIP-003-3 was filed for Commission approval on December 29, 2009 in Docket No. RD09-7-002 and was approved on March 31, 2010.[17] CIP-003-4 was submitted for Commission approval on February 10, 2011 in Docket No. RM11-11-000 and was approved on April 19, 2012.[18]

In Order No. 706 at paragraph 342 the Commission stated that:

> Reliability Standard CIP-003-1 seeks to ensure that each responsible entity has minimum security management controls in place to protect the critical cyber assets identified pursuant to CIP-002-1. To achieve this goal, a responsible entity must develop a cyber security policy that represents management's commitment and ability to secure its critical cyber assets. It also must designate a senior manager to direct the cyber security program and to approve any exception to the policy.

All outstanding directives in Order No. 706 will be addressed in Version 5 of the CIP Standards and the retirement of CIP-003-3, -4 R1.2 does not impact a Commission directive.

Technical Justification

The importance of the cyber security policy as representing management's commitment and ability to secure critical cyber assets is overshadowed by the rigorous and specific training, procedural and process related requirements of the CIP Standards. These trainings, procedures and processes render having the cyber security policy readily available an unnecessary requirement. In other words, whether CIP personnel are completing a typical CIP requirement cyber security task or responding to an immediate situation, they will act via their specific training, processes and procedures and not the overarching cyber security policy. Consequently, the cyber security policy's generalized guidance on compliance with the CIP requirements is not a document that adds value to personnel protecting the BES from a cyber attack on a day-to-day basis.

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[15] *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 FERC ¶ 61,040 (2008) ("Order No. 706"), *order on reh'g*, Order No. 706-A, 123 FERC ¶ 61,174 (2008), *order on clarification*, Order No. 706-B, 126 FERC ¶ 61,229, order on clarification, Order No. 706-C, 127 FERC ¶ 61,273 (2009).

[16] *Order Approving Revised Reliability Standard for Critical Infrastructure Protection and Requiring Compliance Filing*, 128 FERC ¶ 61,291 (2009), *order denying reh'g and granting clarification*, 129 FERC ¶ 61,236 (2009) (approving Version 2 of the CIP Reliability Standards)).

[17] *Order on Compliance* 130 FERC ¶ 61,271 (2010).

[18] *Version 4 Critical Infrastructure Protection Reliability Standards*, 139 FERC ¶ 61,058 (2012).

Furthermore, to implement CIP-003-3, -4 R1.2 entities have undertaken a variety of administrative solutions including kiosks dedicated to computers with the cyber security policy, posting the policy on the company intranet, having copies available in work stations, at common area desks in generating stations and substations, etc. Therefore, although the cyber security policy is readily available for all personnel who have access to, or are responsible for, Critical Cyber Assets, these personnel are specifically and appropriately focused on implementing the procedures and processes required by CIP Reliability Standards such as CIP-007-3 R1, which states as follows:

> Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007-3, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.

Generally the cyber security policy will cite CIP-007-3 R1 as a requirement, and may refer to procedures related to CIP-007-3 R1, but will not have, nor is it required to have, the detail necessary to implement CIP-007-3 R1. In some larger companies, it is also common to have specific procedures on how to accomplish requirements such as CIP-007-3 R1 in a control center versus a generating plant or substation, and it may be different CIP personnel implementing these procedures in locations many hundreds of miles, states or Interconnections away from each other. The value of a more general cyber security policy to these individuals is minimal, at best, and, therefore, does not support reliability. Also, making it readily available at all office locations is an unnecessarily burdensome administrative task.

Moreover, to place every procedure and process to comply with CIP in the cyber security policy is also not practical or effective, because such a large policy will only distract from CIP personnel being able to specifically focus on the task before them. As already stated, there are likely some differences between implementing a requirement like CIP-007-1 R1 in a control center that may be located in one state and for generators located several states and hundreds of miles away. Thus, making the cyber security policy readily available is an administrative task that does little, if anything, to benefit or protect the reliable operation of the BES (Criteria A and B1).

In this context, also consider the inefficiencies CIP-003-3, -4 R1.2 may be causing the ERO compliance program. In companies with hundreds of personnel who have access to, or are responsible for, Critical Cyber Assets in multiple states and Interconnections, the ERO may expend a significant amount of time and resources to monitor compliance with CIP-003-3, -4 R1.2 via a review of kiosks, intranet sites, office cubicles, desks, etc in

multiple locations. Accordingly, considerable efficiency gains will be obtained for the ERO's compliance program if CIP-003-3, -4 R1.2 is retired.

Criterion A
Making the cyber security policy readily available is an administrative task that does little, if anything, to benefit or protect the reliable operation of the BES.

Criteria B

- Criterion B1 (Administrative)

Criteria C

1. CIP-003-3, -4 R1.2 has been part of a FFT filing.[19]

2. As is the case with all the CIP requirements (other than CIP-001-2a R4) proposed for retirement in this technical paper, CIP-003-3, -4 R1.2 is part of an on-going Standards Development Project 2008-06 (Cyber Security) ("CIP V5"). The P81 SDT has coordinated its efforts with the chair of Project 2008-06. There is no conflict between CIP requirements proposed in this technical white paper for retirement and the direction of Project 2008-06. The CIP V5 requirements are not Board of Trustee or Commission approved, and, even if they were, the effective date of CIP V5 is unknown and likely at least a year, maybe more, into the future. Thus, unlike the other requirements presented here for informational purposes, it is appropriate to maintain all the CIP requirements discussed in this technical paper within the scope of the P81 Project to secure the efficiency gains resulting to the ERO compliance program from their retirement.

3. CIP-003-3, -4 R4.2 has a Lower VRF. As explained above, CIP-003-3, -4 R4.2 is not an important part of a scheme of CIP requirements, and, therefore, it is appropriate to propose it for retirement.

4. CIP-003-3,-4 R1.2 is in the second tier of the AML. As explained above, CIP-003-3, -4 R4.2 is not an important part of a scheme of CIP requirements, and, therefore, it is appropriate to propose it for retirement.

5. Given its administrative nature, CIP-003-3, -4 R1.2 does not negatively impact NERC's published and posted reliability principles. The two reliability principles that appear applicable to CIP-003-3, -4 R1.2 are the following:

   Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

[19] NERC FFT Informational Filing, Docket No. RC12-1-000 (October 31, 2011).

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks.

As stated above, other CIP requirements are replete with the requirements that CIP personnel implement to protect the BES from cyber attacks.

6. Retiring CIP-003-3, -4 R1.2 does not negatively impact defense in depth because no other requirement depends on the cyber security policy being readily available. Therefore, the removal of CIP-003,-3,-4 R1.2 cannot have a negative impact on defense in depth.

7. Retirement of CIP-003-3, -4 R1.2 promotes a results-based approach because the requirement is mechanistic and administrative, and does not provide the foundation for performing a reliability task.

Accordingly, for the above reasons, it is appropriate to retire CIP-003-3, -4 R1.2.

CIP-003-3, -4 R3, R3.1, R3.2, R3.3 – Cyber Security – Security Management Controls

R3. Exceptions – Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).

R3.1. Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).

R3.2. Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures.

R3.3. Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.

Background/Commission Directives

CIP-003-1 was filed for Commission approval on August 28, 2006 in Docket No. RM06-16-000 and was approved on January 18, 2008 in Order No. 706.[20] CIP-003-2 was filed for Commission approval on May 22, 2009 in Docket Nos. RM06-22-000 and RD09-7-

[20] *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 FERC ¶ 61,040 (2008) ("Order No. 706"), *order on reh'g*, Order No. 706-A, 123 FERC ¶ 61,174 (2008), *order on clarification*, Order No. 706-B, 126 FERC ¶ 61,229, order on clarification, Order No. 706-C, 127 FERC ¶ 61,273 (2009).

000 and was approved on September 30, 2009.[21] CIP-003-3 was filed for Commission approval on December 29, 2009 in Docket No. RD09-7-002 and was approved on March 31, 2010.[22] CIP-003-4 was submitted for Commission approval on February 10, 2011 in Docket No. RM11-11-000 and was approved on April 19, 2012.[23]

In Order No. 706 at paragraphs 373 and 376 the Commission stated that:

> Requirement R3 provides that a responsible entity must document exceptions to its policy with documentation and senior management approval. The Commission is concerned that, if exceptions mount, there would come a point where the exceptions rather than the rule prevail. In such a situation, it is questionable whether the responsible entity is actually implementing a security policy. We therefore believe that the Regional Entities should perform an oversight role in providing accountability of a responsible entity that excepts itself from compliance with the provisions of its cyber security policy. Further, we believe that such oversight would impose a limited additional burden on a responsible entity because Requirement R3 currently requires documentation of exceptions.
>
> Further, the Commission adopts its CIP NOPR proposal and directs the ERO to clarify that the exceptions mentioned in Requirements R2.3 and R3 of CIP-003-1 do not except responsible entities from the Requirements of the CIP Reliability Standards. In response to EEI, we believe that this clarification is needed because, for example, it is important that a responsible entity understand that exceptions that individually may be acceptable must not lead cumulatively to results that undermine compliance with the Requirements themselves.

All outstanding directives in Order No. 706 will be addressed in Version 5 of the CIP Standards and the retirement of CIP-003-3, -4 R3, R3.1, R3.2, and R3.3 do not impact a Commission directive.

Technical Justification

CIP-003-3, -4 R3, R3.1, R3.2, and R3.3 (CIP exception requirements) have proven not to be useful and have been subject to misinterpretation. For instance, although the CIP exception requirements have not been available for use to exempt an entity from compliance with any requirement of any Reliability Standard, based on questions received by NERC CIP Staff, entities may be interpreting the CIP exception requirements to allow for such an exemption. The CIP exception requirements only apply to

[21] *Order Approving Revised Reliability Standard for Critical Infrastructure Protection and Requiring Compliance Filing*, 128 FERC ¶ 61,291 (2009), *order denying reh'g and granting clarification*, 129 FERC ¶ 61,236 (2009) (approving Version 2 of the CIP Reliability Standards)).

[22] *Order on Compliance* 130 FERC ¶ 61,271 (2010).

[23] *Version 4 Critical Infrastructure Protection Reliability Standards*, 139 FERC ¶ 61,058 (2012).

exceptions to internal corporate policy, and only in cases where the policy exceeds a Reliability Standard requirement or addresses an issue that is not covered in a Reliability Standard. For example, if an internal corporate policy statement requires that all passwords be a minimum of eight characters in length, and be changed every 30 days, which is over and above what is required in CIP-007-3 R5.3, the CIP exception requirements could be invoked for internal governance purposes to lessen the corporate requirement back to the password requirements in CIP-007-3 R5.3, but under no circumstances do the CIP exception requirements authorize the implementation of security measures less than what is required in CIP-007-3 R5.3.

The retirement of the CIP exception requirements would not impact an entity's ability to maintain such an exception process within their corporate policy governance procedures, if it so desired. Consequently, the CIP exception requirements were always an internal administrative and documentation requirement that is outside the scope of the other CIP requirements (Criteria B1 and B3). In this context, the CIP exception requirements do not support the level of reliability set forth in the Reliability Standards, and are unnecessarily burdensome because they have resulted in entities implementing practices due to a misinterpretation of the requirement that has caused them to allocate time and resources to tasks that are misaligned with the requirements themselves. Unfortunately, this misunderstanding has also impacted the efficiency of the ERO compliance program because of the amount of time and resources needed to clear up the misunderstanding and coach entities on the meaning of the CIP exception requirements. These inefficiencies would be eliminated with the retirement of the CIP exception requirements. Accordingly, as explained, the CIP exception requirements are an administrative tool for internal corporate governance procedures, and, therefore, are not requirements that are necessary or directly protect the BES from a cyber attack, the tasks associated with these requirements do little, if anything, to benefit or protect the reliable operation of the BES. (Criterion A).

Criterion A
The CIP exception requirements are a tool for internal corporate governance procedures and is not a requirement directly protecting the BES from a cyber attack, and, therefore, the tasks associated with these requirements do little, if anything, to benefit or protect the reliable operation of the BES.

Criteria B

- Criterion B1 (Administrative)
- Criterion B3 (Documentation)

Criteria C

1. The CIP exception requirements have been part of a FFT filing.[24]

[24] NERC FFT Informational Filing, Docket No. RC12-7-000 (January 31, 2012); NERC FFT Informational Filing, Docket No. RC12-6-000 (December 30, 2011).

2. The CIP exception requirements are part of an on-going Standards Development Project 2008-06 (Cyber Security). As detailed in the discussion of CIP-003-3, -4 R1.2, the P81 SDT has coordinated its efforts with the chair of Project 2008-06 and there is no conflict between the CIP exception requirements proposed in this technical white paper for retirement and the direction of Project 2008-06.

3. The CIP exception requirements each have a Lower VRF. As explained above, they are not an important part of a scheme of CIP requirements, and, therefore, it is appropriate to propose it for retirement.

4. The CIP exception requirements are on the third tier of the AML. As explained above, they are not an important part of a scheme of CIP requirements, and, therefore, it is appropriate to propose it for retirement.

5. Given the administrative and unnecessary nature of the CIP exception requirements in relation to protecting the BES from cyber attacks, retirement does not pose any negative impact to NERC's published and posted reliability principles, of which only Principle 8 appears to apply: "Bulk power systems shall be protected from malicious physical or cyber attacks."

6. Retiring the CIP exception requirements does not negatively impact any defense in depth strategy because no other requirement depends on it to help cover a reliability gap or risk to reliability.

7. Retirement of the CIP exception requirements promotes a results-based approach because the CIP exception requirements are approaches that entities may voluntarily take to handle internal corporate governance procedures, and, therefore, do not provide the foundation for performing a required reliability task.

Accordingly, for the above reasons, it is appropriate to retire the following CIP exception requirements: CIP-003-3, -4 R3, R3.1, R3.2, and R3.3.

CIP-003-3, -4 R4.2 - Cyber Security – Security Management Controls

> **R4.2.** The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.

Background/Commission Directives

CIP-003-1 was filed for Commission approval on August 28, 2006 in Docket No. RM06-16-000 and was approved on January 18, 2008 in Order No. 706.[25] CIP-003-2 was filed for Commission approval on May 22, 2009 in Docket Nos. RM06-22-000 and RD09-7-

[25] *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 FERC ¶ 61,040 (2008) ("Order No. 706").

000 and was approved on September 30, 2009.[26] CIP-003-3 was filed for Commission approval on December 29, 2009 in Docket No. RD09-7-002 and was approved on March 31, 2010.[27] CIP-003-4 was submitted for Commission approval on February 10, 2011 in Docket No. RM11-11-000 and was approved on April 19, 2012.[28] In Order No. 706, the Commission did not specifically address CIP-003-3, -4 R4.2.

All outstanding directives in Order No. 706 will be addressed in Version 5 of the CIP Standards and the retirement of CIP-003-3, -4 R4.2 does not impact a Commission directive.

Technical Justification

The task of classifying Critical Cyber Information "based on the sensitivity" does little, if anything, to benefit or protect the reliable operation of the BES, and is an unnecessarily administrative and a documentation task that is redundant with CIP-003-3, -4 R4 (Criteria A, B1, B3 and B7). Specifically, CIP-003-3, -4 R4[29] already requires the classification of information associated with Critical Cyber Assets. The only difference between R4 and R4.2 is that the subjective term "based on the sensitivity" has been added, thus, making it essentially redundant. Further, CIP-003-3, -4 R4 since requires the entity to develop classifications based on a subjective understanding of sensitivity (*i.e.*, no clear connection to serving reliability), the requirement does not support reliability. In this context, classifying based on sensitivity becomes an administrative that becomes necessarily burdensome, because of all the possible ramifications "based on sensitivity" can produce, and, therefore, require SMEs to decide on and reduce to writing in a documented program. This is time and effort that could be better spent on other CIP activities that provide value to cyber security and actively protect the BES. For similar reasons, retiring CIP-003-3, -4 R4.2 and the term "based on sensitivity" would increase the efficiencies of the ERO compliance program on several levels. The ERO would not spend time and resources on reviewing whether an entity's documentation contained classifications "based on sensitivity," and, instead would be able to focus its time and resources monitoring compliance with the entity's program to identify, classify, and protect information associated with Critical Cyber Assets (R4), without any distraction on monitoring the subjective implementation of classifications based on sensitivity (R4.2).

Criterion A

The task of classifying Critical Cyber Information "based on the sensitivity" does little, if anything, to benefit or protect the reliable operation of the BES, and is an administrative and a documentation task that is redundant with CIP-003-3, -4 R4.

[26] *Order Approving Revised Reliability Standard for Critical Infrastructure Protection and Requiring Compliance Filing*, 128 FERC ¶ 61,291 (2009), *order denying reh'g and granting clarification*, 129 FERC ¶ 61,236 (2009) (approving Version 2 of the CIP Reliability Standards)).
[27] *Order on Compliance* 130 FERC ¶ 61,271 (2010).
[28] *Version 4 Critical Infrastructure Protection Reliability Standards*, 139 FERC ¶ 61,058, (2012).
[29] "**R4**. Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets."

Criteria B

- Criterion B1 (Administrative)
- Criterion B3 (Documentation)
- Criterion B7 (Redundant)

Criteria C

1. CIP-003-3, -4 R4.2 has been part of a FFT filing.[30]

2. CIP-003-3, -4 R4.2 is part of an on-going Standards Development Project 2008-06 (Cyber Security). As detailed in the discussion of CIP-003-3, -4 R1.2, the P81 SDT has coordinated its efforts with the chair of Project 2008-06 and there is no conflict between retirement of CIP-003-3, -4 R4.2 and the direction of Project 2008-06.

3. CIP-003-3, -4 R4.2 has a Lower VRF. As explained above, CIP-003-3, -4 R4.2 is not an important part of a scheme of CIP requirements, and, therefore, it is appropriate to propose it for retirement.

4. CIP-003-3, -4 R4.2 is on the third tier of the AML. As explained above, CIP-003-3, -4 R4.2 is not an important part of a scheme of CIP requirements, and, therefore, it is appropriate to propose it for retirement.

5. Given the unnecessary and redundant nature of this requirement, retirement does not pose any negative impact to NERC's published and posted reliability principle No. 8 which appears to apply: "Bulk power systems shall be protected from malicious physical or cyber attacks."

6. Retirement of CIP-003-3, -4 R4.2 does not negatively impact defense in depth because no other requirement depends on it to help cover a reliability gap or risk to reliability.

7. Retirement of CIP-003-3, -4 R4.2 promotes a results-based approach because retiring CIP-003-3, -4 R4.2 moves away from prescriptive, checklist of documentation approach to Reliability Standard requirements.

Accordingly, for the above reasons, it is appropriate to retire CIP-003-3, -4 R4.2.

CIP-005-3a, -4a R2.6 – Cyber Security – Electronic Security Perimeter(s)

R2.6. Appropriate Use Banner -- Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen

[30] NERC FFT Informational Filing, Docket No. RC12-7-000 (January 31, 2012); NERC FFT Informational Filing, Docket No. RC12-1-000 (October 31, 2011).

upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.

Background/Commission Directives

CIP-005-1 was filed for Commission approval on August 28, 2006 in Docket No. RM06-16-000 and was approved on January 18, 2008 in Order No. 706.[31] CIP-005-2 was filed for Commission approval on May 22, 2009 in Docket Nos. RD09-7-000 and RM06-22-000 and was approved on September 30, 2009.[32] CIP-005-2a was filed for Commission approval on April 21, 2010 in Docket No. RD10-12-000 and was approved by unpublished letter order on February 2, 2011.[33] CIP-005-3 was filed for Commission approval on December 29, 2009 in Docket No. RD09-7-002 and was approved on March 31, 2010.[34] CIP-005-3a was filed for Commission approval on April 21, 2010 in Docket No. RD10-12-000 and was approved by an unpublished letter order on February 2, 2011.[35] CIP-005-4 was filed for Commission approval on February 10, 2011 in Docket No. RM11-11-000 and was approved on April 19, 2012 in Order No. 761.[36] CIP-005-4a was filed for Commission approval as errata to the CIP Version 4 Petition on April 12, 2011 in Docket No. RM11-11-000 and was approved on April 19, 2012 in Order No 761, the Final Rule on the CIP Version 4 standards.[37]

In Order 706 at paragraph 505 the Commission noted that:

> Requirement R2 of CIP-005-1 requires a responsible entity to implement organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the electronic security perimeter.

All outstanding directives in Order No. 706 will be addressed in Version 5 of the CIP Standards and the retirement of CIP-005-3, -4 R2.6 does not impact a Commission directive.

[31] *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 FERC ¶ 61,040 (2008) ("Order No. 706").
[32] *Order Approving Revised Reliability Standard for Critical Infrastructure Protection and Requiring Compliance Filing*, 128 FERC ¶ 61,291 (2009), *order denying reh'g and granting clarification*, 129 FERC ¶ 61,236 (2009) (approving Version 2 of the CIP Reliability Standards)).
[33] Letter Order, Petition of the North American Electric Reliability Corporation for Approval of Interpretation to Reliability Standard CIP-005-1, Cyber Security, Electronic Security Perimeter(s), Section 4.2.2 and Requirement R1.3., Docket RD10-12-000, (February 2, 2011).
[34] *Order on Compliance* 130 FERC ¶ 61,271 (2010).
[35] Letter Order, Petition of the North American Electric Reliability Corporation for Approval of Interpretation to Reliability Standard CIP-005-1, Cyber Security, Electronic Security Perimeter(s), Section 4.2.2 and Requirement R1.3., Docket RD10-12-000, (February 2, 2011).
[36] *Version 4 Critical Infrastructure Protection Reliability Standards*, 139 FERC ¶ 61,058 (2012).
[37] *Id.*

Technical Justification

The implementation of an appropriate use banner ("banner") on a user's screen for all interactive access attempts into the Electronic Security Perimeter ("ESP") is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES. Specifically, the banner does not support reliability because people who intend to inappropriately use sites will simply ignore the banner. (Criterion A). The banner is also is an administrative task since it simply requires a message be displayed on an access screen. Furthermore, the implementation and administration of a non-beneficial tool, such as the banner, therefore creates a needlessly burdensome task. As mentioned, above, the ineffectiveness of the banner also indicates that it does not support reliability. (Criteria B1 and B3). In addition, banners of this type are generally considered to be a form of legal protection or mitigation of liability, rather than security protection. Furthermore, the banner does not ensure a proper or secure access point configuration which is generally the purpose of CIP-005-3a, -4a. Further, this requirement has also been the subject of numerous TFEs for devices that cannot support such a banner, and hence has diverted resources from more productive efforts. Thus, the ERO's compliance program would become more efficient if CIP-005-3a, -4a R2.6 was retired, because ERO time and resources could be reallocated to monitor compliance with the remainder of CIP-005-3a, -4a, which provides for more effective controls of electronic access at all electronic access points into the ESP.

Criterion A

The implementation of an appropriate use banner on a user's screen for all interactive access attempts into the ESP is an activity or task that does little, if anything, to benefit or protect reliable operation of the BES, because it is administrative and a static electronic message that is not an effective deterrent or control against unauthorized access.

Criteria B

- Criterion B1 (Administrative)
- Criterion B3 (Documentation)

Criteria C

1. CIP-005-3a, -4a R2.6 has been part of a FFT filing.[38]

2. CIP-005-3a, -4a R2.6 is part of an on-going Standards Development Project 2008-06 (Cyber Security). As detailed in the discussion of CIP-003-3, -4 R1.2, the P81 SDT has coordinated its efforts with the chair of Project 2008-06 and there is no conflict between retirement of CIP-005-3a, -4a R2.6 and the direction of Project 2008-06.

[38] NERC FFT Informational Filing, Docket No. RC12-13-000 (June 29, 2012); NERC FFT Informational Filing, Docket No. RC12-7-000 (January 31, 2012).

3. The VRF for CIP-005-3a, -4a R2.6 is Lower. As explained above, CIP-005-3a, -4a R2.6 is not an important part of a scheme of CIP requirements, and, therefore, it is appropriate to propose it for retirement.

4. CIP-005-3a, -4a R2.6 is on the first tier of the AML; however, given its clear ineffective nature the placement on the first tier is not dispositive of whether it should be retired.

5. Reliability principle No. 8 – "Bulk power systems shall be protected from malicious physical or cyber attacks" – is not implicated or negatively impacted by the retirement of CIP-005-3a, -4a R2.6, because it is not an effective deterrent or control to unauthorized access into an ESP.

6. The retirement of this requirement does not negatively impact defense in depth because no other requirement depends on it to help cover a reliability gap or risk to reliability. Furthermore, the remainder of CIP-005-3a, -4a provides for actual controls of electronic access at all electronic access points which addresses the reliability risk associated with unauthorized access into an ESP.

7. Its retirement also promotes a results-based approach because CIP-005-3a, -4a R2.6 is an ineffective administrative task, and, therefore, does not provide the foundation for performing a reliability task.

Accordingly, for the above reasons, it is appropriate to retire CIP-005-3a, -4a R2.6.

CIP-007-3, -4 R7.3 – Cyber Security – Systems Security Management

R7.3. The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.

Background/Commission Directives

CIP-007-1 was filed for Commission approval on August 28, 2006 in Docket No. RM06-16-000 and was approved on January 18, 2008 in Order No. 706.[39] CIP-007-2 was filed for Commission approval on May 22, 2009 in Docket Nos. RM06-22-000 and RD09-7-000 and was approved on September 30, 2009.[40] CIP-007-2a was filed for Commission approval on November 17, 2009 in Docket No. RD10-3-000 and was approved on March 18, 2010.[41] CIP-007-3 was filed for Commission approval on December 29, 2009 in Docket No. RD09-7-002 and was approved on March 31, 2010.[42] CIP-007-4 was filed

[39] *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 FERC ¶ 61,040 (2008) ("Order No. 706").
[40] *Order Approving Revised Reliability Standard for Critical Infrastructure Protection and Requiring Compliance Filing*, 128 FERC ¶ 61,291 (2009), *order denying reh'g and granting clarification*, 129 FERC ¶ 61,236 (2009) (approving Version 2 of the CIP Reliability Standards)).
[41] Order Approving Reliability Standard Interpretation, 130 FERC ¶ 61,184 (2010).
[42] *Order on Compliance* 130 FERC ¶ 61,271 (2010).

for Commission approval on February 10, 2011 in Docket No. RM11-11-000 and was approved on April 19, 2012.[43]

In Order No. 706 at paragraph 631 the Commission stated that:

> Requirement R7 of CIP-007-1 requires the responsible entity to establish formal methods, processes and procedures for disposal or redeployment of cyber assets. In the CIP NOPR, the Commission addressed the concern that solely to "erase the data," as stated several times in Requirement R7, may not be adequate because technology exists that allows retrieval of "erased" data from storage devices, and that effective protection requires discarded or redeployed assets to undergo high quality degaussing. We noted that erasure is as much a method as it is a goal, and that the requirement ultimately needs to assure that there is no opportunity for unauthorized retrieval of data from a cyber asset prior to discarding it or redeploying it. Degaussing is not the sole means for achieving this goal. The Commission therefore proposed to direct the ERO to modify Requirement R7 to clarify this point. (Footnote omitted)

This Commission directive is unaffected by the retirement of CIP-007-3,-4 R7.3 as explained below.

Technical Justification

Outside the context of a Reliability Standard, under Section 400 of the NERC Rules of Procedure, NERC and the Regional Entities have the authority to require an entity to submit data and information for purposes of monitoring compliance. [44] CIP-007-3, -4 R7.3 requires the maintaining of records for the purpose of demonstrating compliance with disposing of or redeploying of Cyber Assets in accordance with documented procedures. NERC and the Regions Entities, however, under Section 400 already have the ability to require the production of records to demonstrate compliance, thus it is unnecessary to also state the same in CIP-007-3, -4 R7.3. The maintaining of records is an administrative task, not a task directly related to the protection of the BES from a cyber attack. The maintaining of records is not a task that by itself, or in conjunction with other requirements, supports reliability. Also, the maintaining of the records becomes unnecessarily burdensome in that it requires all records be maintained, which

[43] *Version 4 Critical Infrastructure Protection Reliability Standards*, 139 FERC ¶ 61,058 (2012).

[44] Section 401 of NERC's Rules of Procedure provide for collection of data and information necessary to monitor compliance outside the context of Reliability Standards:

> **Data Access** — All Bulk Power System owners, operators, and users shall provide to NERC and the applicable Regional Entity such information as is necessary to monitor compliance with the Reliability Standards. NERC and the applicable Regional Entity will define the data retention and reporting requirements in the Reliability Standards *and compliance reporting procedures.* (emphasis added).

may or may not be necessary to demonstrate compliance via the production of information under Section 400. (Criteria B1 and B2). As mentioned, CIP-007-3, -4 R7.3 does not promote reliability because it does not protect the BES from a cyber attack, instead it is a record retention activity. Therefore, CIP-007-3, -4 R7.3 requires an activity or task that in and of itself, does little, if anything, to benefit or protect the reliable operation of the BES. (Criteria A).

In contrast, the remaining substantive requirements in R7 read as follows:

> R7. Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-3.
>
> R7.1. Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.
>
> R7.2. Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.

An entity's following of these requirements may help to protect BES reliability, but the retention of evidence associated with these requirements does not. Hypothetically, an entity could perform R7, R7.1 and R7.2 flawlessly and protect the BES, but not have any record of it. While this situation may impact a demonstration of compliance, the lack of records does not necessarily directly impact the reliability of the BES or protect it from a cyber attack.

Also, there are some inherent inefficiencies resulting from a small number of Reliability Standard requirements mandating the collection of data, evidence and records, while most data and information is collected for ERO compliance monitoring purposes outside the context of Reliability Standards. In this regard, for the ERO, Regional Entities and the entities, arguably Reliability Standards are more difficult to understand because of this inconsistent approach (typically only implicitly requiring documentation as a part of an obligation to prove compliance, but occasionally explicitly requiring it with no discernible pattern or rationale).

Criterion A

CIP-007-3, -4 R7.3 does promote reliability because it does not protect the BES from a cyber attack, instead it is a record retention activity. Therefore, CIP-007-3, -4 R7.3 requires an activity or task that in and of itself, does little, if anything, to benefit or protect the reliable operation of the BES.

Criteria B

- Criterion B1 (Administrative)
- Criterion B2 (Data Collection/Data Retention)

Criteria C

1. CIP-007-3, -4 R7.3 has not been part of a FFT filing.

2. CIP-007-3, -4 R7.3 is part of an on-going Standards Development Project 2008-06 (Cyber Security). As detailed in the discussion of CIP-003-3, -4 R1.2, the P81 SDT has coordinated its efforts with the chair of Project 2008-06 and there is no conflict between retirement of CIP-007-3, -4 R7.3 and the direction of Project 2008-06.

3. The VRF for CIP-007-3, -4 R7.3 is Lower. As explained above, CIP-007-3, -4 R7.3 is not an important part of a scheme of CIP requirements, and, therefore, it is appropriate to propose it for retirement.

4. CIP-007-3, -4 R7.3 is on the first tier of the AML; however, given that it is simply requiring the retention of records the fact that is on the first tier is not dispositive of whether it should be retired.

5. Given the administrative, data collection nature of this requirement, retirement does not pose any negative impact to NERC's published and posted reliability principle No. 8: "Bulk power systems shall be protected from malicious physical or cyber attacks."

6. The retirement does not negatively impact defense in depth because data retention in-and-of-itself is not an activity that other requirements depend on to help cover a reliability gap or risk to reliability.

7. Its retirement promotes a results-based approach because the data collection/retention does not provide the foundation for performing a reliability task.

Accordingly, for the above reasons, it is appropriate to retire CIP-007-3, -4 R7.3.

EOP-004-1 R1 – Disturbance Reporting

R1. Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.

Background/Commission Directives

EOP-004-1 was submitted to the Commission for approval on November 15, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[45] Although the Commission did not address EOP-004-1 R1 directly, in Order No. 693 at paragraph 617 it stated that EOP-004-1:

> . . . serves an important purpose in establishing requirements for reporting and analysis of system disturbances. Accordingly, the Commission approves Reliability Standard EOP-004-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-004-1 through the Reliability Standards development process that includes any Requirements necessary for users, owners and operators of the Bulk-Power System to provide data that will assist NERC in the investigation of a blackout or disturbance.

The directive to provide data that will assist NERC in the investigation of a blackout or disturbance is not affected by the EOP-004-1 R1, because that is accomplished via other requirements in EOP-004-1 and is also under consideration for enhancement in the development of EOP-004-2.

Technical Justification

The reliability purpose of EOP-004-1 is to ensure that disturbances or unusual occurrences that jeopardize the operation of the BES, or result in system equipment damage or customer interruptions, are studied and understood in order to minimize the likelihood of similar events in the future. The reliability purpose of EOP-004-1 is unaffected by the proposed retirement of R1.

EOP-004-1 R1 is an anomaly in the Reliability Standards, given that it requires the Regional Reliability Organization to develop a reporting procedure. Although the development of such a reporting procedure may be helpful guidance to responsible entities on reporting of disturbances to Regional Entities, in and of itself is an administrative and documentation task that does little, if anything, to benefit or protect the reliable operation of the BES. (Criteria A, B1 and B3). It is worth noting that EOP-004-1 R1, like CIP-001-2a R4, is administrative in that it only requires the development of procedures, it does not require that they be followed. More importantly, the mandatory processes for reporting preliminary and final disturbance reports are set forth in EOP-004-1 R3 and its sub-requirements which read as follows:

> R3. A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.

[45] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

> R3.1. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized.
>
> R3.2. Applicable reporting forms are provided in Attachments 1-EOP-004 and 2- EOP-004.
>
> R3.3. Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall promptly notify its Regional Reliability Organization(s) and NERC, and verbally provide as much information as is available at that time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.
>
> R3.4. If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.

There is no reliability gap created by the passive retirement of EOP-004-1 R1, because EOP-004-1 R3 and its sub-requirements require considerable action to report on disturbances.[46] Also, consider that the EOP-004-1 R1 regional procedures may take the lead from NERC, and, therefore, the regional procedures become a reiteration or a hybrid of mandatory (EOP-004-1 R3 and its sub-requirements) and voluntary rules (NERC

[46] While not dispositive, the NERC voluntary event analysis process is also being used to report and analyze events. A link to NERC's event analysis process is http://www.nerc.com/page.php?cid=5|365.

Event Analysis Process).[47] It is an unnecessarily burdensome task to require such reiterations of NERC reporting requirements on a regional level. Also, if there was a need for particular regional procedures such procedures could exist as guidance even without the existence of EOP-004-1 R1. Thus, the value of EOP-004-1 R1 as a Reliability Standard requirement to support reliability is diminutive.

Furthermore, the retirement of EOP-004-1 R1 will increase the efficiency of the ERO compliance program in that the time and resources spent monitoring EOP-004-1 and checking off whether or not a Regional Entity has the specified procedure, and can be utilized to focus attention on an entity's compliance with EOP-004-1 R3 and its sub-requirements, which produce the information related to disturbances.

Criterion A
A requirement that Regional Entities develop a reporting procedure in and of itself is an administrative and documentation task that does little, if anything, to benefit or protect the reliable operation of the BES.

Criteria B
- Criterion B1 (Administrative)
- Criterion B3 (Documentation)

Criteria C
1. EOP-004-1 R1 has not been part of a FFT filing.

2. EOP-004-1 R1 is part of an on-going Standards Development Project 2009-01 (EOP-004-2) and is being proposed for retirement as unnecessary. At this time, EOP-004-2 has not been approved by stakeholders and the NERC Board of Trustees, and, therefore, it is appropriate to retain EOP-004-1 R1 within the scope of the P81 Project. However, if EOP-004-2 does receive stakeholder approval and is adopted by the NERC Board of Trustees, the SDT will reconsider retirement via the P81 Project and may include EOP-004-1 R1 for informational purposes only.

3. The VRF for EOP-004-1 R1 is Lower.

4. EOP-004-1 R1 is in the third tier of the AML.

5. The retirement of EOP-004-1 R1 does not pose any negative impact to NERC's published and posted reliability principles, as none of the principles are directly implicated.

[47] *See, e.g.*, FRCC Disturbance Reporting Procedure, FRCC – RE – OP – 001-0 Effective Date – February 10, 2012.

6. The retirement does not negatively impact defense in depth because no other requirement depends on it to help cover a reliability gap or risk to reliability.

7. The retirement of EOP-004-1 R1 promotes a results-based approach because the requirement is an administrative task of developing a procedure with no associated actionable performance of a task that impacts reliability.

Accordingly, for the above reasons, it is appropriate to retire EOP-004-1 R1.

EOP-005-2 R3.1– System Restoration from Blackstart Resources

R3.1. If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary.

Background/Commission Directives

EOP-005-1 was submitted for Commission approval on August 28, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[48] EOP-005-2 was submitted for Commission approval on December 31, 2009 in Docket No. RM10-16-000 and was approved on March 17, 2011 in Order No. 749.[49] Although the Commission did not address EOP-005-2 R3 directly in Order No. 749, it stated at paragraph 17 the following:

> EOP-005-2 and EOP-006-2 clarify the responsibilities of the reliability coordinator and transmission operator in the restoration process and restoration planning and address the Commission's directives in Order No. 693 related to the EOP Standards. By enhancing the rigor of the restoration planning process, the Reliability Standards represent an improvement from the current Standards and will improve the reliability of the Bulk-Power System. The Commission is not directing any modifications to the three new Reliability Standards. Nevertheless, as discussed below, commenters raised several issues for consideration, at the time these standards are next revisited, which we believe could improve these new Reliability Standards

There are no outstanding Commission directives that are affected by the proposed retirement of EOP-005-2 R3.1.

[48] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 (2007).
[49] *System Restoration Reliability Standards*, 134 FERC ¶ 61,215, (March 17, 2011) ("Order No. 749"), *order on clarification*, 136 FERC ¶ 61,030 ("Order No. 749-A") (2011).

Technical Justification

The reliability purpose of EOP-005-2 is to ensure that plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to assure that reliability is maintained during restoration and priority is placed on restoring the Interconnection. This reliability purpose is unaffected by the proposed retirement of R3.1.

A review of EOP-005-2 R3.1 indicates that this requirement is redundant with EOP-005-2 R3 and a duplicative administrative update that does little, if anything, to benefit or protect the reliable operation of the BES. (Criteria A, B1, B5 and B7). The primary reason EOP-005-2 R3.1 is unnecessary is that EOP-005-2 R3 already requires the Transmission Operator to submit its restoration plan to its Reliability Coordinator whether or not the plan includes changes. EOP-005-2 R3 reads:

> Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually agreed predetermined schedule.

Consequently, since R3 requires the Transmission Operator to submit its restoration plan to the Reliability Coordinator whether or not there has been a change, R3.1 only adds a separate, duplicative administrative burden for the entity to also confirm that there were no changes based upon another pre-determined schedule. While R3.1 may have attempted to capture the likelihood that unless there have been significant changes to the entity's BES, there would be no change to the restoration plan, this is an insufficient reason to impose a needlessly burdensome, duplicative administrative requirement relative to the language in R3. EOP-005-2 R3.1 is also clearly needlessly burdensome if one considers that the time and resources of Transmission Operators is better spent reliably operating the BES, rather than submitting paperwork to a Reliability Coordinator on possibly two different pre-determined schedules – one for changes and one for no changes. For these reasons, there is no reliability gap resulting from the retirement of EOP-005-2 R3.1 because Transmission Operators already have an obligation to review and provide its restoration plan annually on a mutually agreed predetermined schedule to its Reliability Coordinator. It could also be argued that a reason for both R3 and R3.1 is for the Reliability Coordinator to organize the Transmission Operator submittals into changes versus no changes. However, with the requirement to annually review restoration plans comes the need to demonstrate and track annual reviews via the revision history index, for example, which quickly shows the Reliability Coordinator when changes have and have not occurred.

The retirement of EOP-005-2 R3.1 would also increase the efficiencies of the ERO compliance program because the ERO would be able to focus its time and resources on R3 which already captures R3.1 and not be concerned with tracking the submission of restoration plans on multiple pre-determined schedules, some with changes and some without changes. Instead, the focus of the ERO compliance program would be on whether the Transmission Operators annually submitted its restoration plan to its

Reliability Coordinator on one pre-determined schedule. Thus, the retirement of EOP-005-2 R3.1 appears to benefit the ERO compliance program.

Criterion A
EOP-005-2 R3.1 is redundant and a duplicative administrative update that does little, if anything, to benefit or protect the reliable operation of the BES.

Criteria B
- Criterion B1 (Administrative)
- Criterion B5 (Periodic Updates)
- Criterion B7 (Redundant)

Criteria C
1. EOP-005-2 R3.1 has not been part of a FFT filing.

2. EOP-005-2 R3.1 is not part of an on-going Standards Development Project.

3. EOP-005-2 R3.1 does not yet have a FERC-approved VRF.

4. EOP-005-2 R3.1 is on the second tier of the AML; however, the duplicative nature of R3 and R3.1 discounts any indication that R3.1 being in the second tier is a reason not to proceed with its retirement.

5. Since EOP-005-2 R3 already requires the Transmission Operator to submit its restoration plan to its Reliability Coordinator whether or not the plan includes changes, retirement of EOP-005-2 R3.1 does not pose any negative impact to the following of NERC's published and posted reliability principles that appear to apply:

   Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

   Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

   Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

6. Retirement of EOP-005-2 R3.1 does not negatively impact defense in depth because no other requirement depends on it to help cover a reliability gap or risk to reliability.

7. The retirement of EOP-005-2 R3.1 promotes a results-based approach because the requirement is administrative and unnecessary, and, therefore, does not provide the foundation for performing a reliability task.

Accordingly, for the above reasons, it is appropriate to retire EOP-005-2 R3.1.

FAC-002-1 R2 – Coordination of Plans for New Facilities

R2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

Background/Commission Directives

FAC-002-0 was submitted to the Commission for approval on April 4, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[50] FAC-002-1 was submitted for Commission approval on September 9, 2010 in Docket No. RD10-15-000 and was approved on January 10, 2011.[51] When approving FAC-002-0 in Order No. 693 at paragraphs 692 and 693, and FAC-002-1 in a subsequent order,[52] the Commission did not directly address R2.

There are no outstanding Commission directives that are affected by the proposed retirement of FAC-002-1 R2.

Technical Justification

Outside the context of a Reliability Standard, under Section 400 of the NERC Rules of Procedure, NERC and the Regional Entities have the authority to require an entity to submit data and information for purposes of monitoring compliance. Thus, without the existence of FAC-002-1 R2, a Regional Entity or NERC has the ability to request and receive "documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems)." This generally would occur during a spot check or compliance audit where entities have the obligation to provide documentation sufficient to demonstrate compliance. In this regard, entities already have the obligation to produce the same information required in R2 to demonstrate compliance to R1 and its sub-requirements, thus making R2 unnecessary. To have a Reliability Standard requirement that is setting forth a data retention requirement and a requirement for the entity to deliver, upon request, that data to NERC

[50] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[51] NERC Petition for Approval of Proposed Modifications to Reliability Standards BAL-002-1; EOP-002-3; FAC-002-1; MOD-021-2; PRC-004-2; and VAR-001-2 RD10-15-000 (January 10, 2011).
[52] *North American Electric Reliability Corporation*, 134 FERC ¶ 61,015 (2011).

or a Regional Entity is unnecessary and also repetitive with the NERC Rules of Procedure. Accordingly, retiring FAC-002-1 R2 presents no gap to reliability or to the information NERC and the Regional Entity need to monitor compliance. Thus, FAC-002-1 R2 is not necessary to support reliability. Consequently, a review of R2 indicates that it is an administrative and data collection requirement that that does little, if anything, to benefit or protect the reliable operation of the BES. (Criteria A, B1 and B2). The compilation of three years of data is a burdensome task, particularly when one considers the resources and time spent on stockpiling this information is better spent coordinating the studies, executing an interconnection agreement and ensuring that interconnections are safely and reliably energized, maintained and operated. Also, there are some inherent inefficiencies that result from a small number of requirements, such as CIP-007-3, -4 R7.3 and FAC-002-1 R2 being data, evidence and record retention requirements, while there are other and more appropriate established methods to collect and review the data than a Reliability Standard via Rules of Procedure Section 401. In this regard, for the ERO, Regional Entities and the entities, arguably Reliability Standards are more difficult to understand because of this inconsistent approach (typically only implicitly requiring documentation as a part of an obligation to prove compliance, but occasionally explicitly requiring it with no discernible pattern or rationale).

Criterion A

A review of FAC-002-1 R2 indicates that it is an administrative and data collection requirement that does little, if anything, to benefit or protect reliable operation of the BES.

Criteria B

- Criterion B1 (Administrative)
- Criterion B2 (Data Collection/Data Retention)

Criteria C

1. FAC-002-1 R2 has not been part of a FFT filing.

2. FAC-002-1 R2 is subject to a future Project 2010-02 Connecting New Facilities to the Grid (a review of FAC-001 and FAC-002) that is scheduled to begin in the second quarter of 2015. It seems appropriate to retire FAC-002-1 R2 at this time as it may also make the review of FAC-001 and FAC-002 more effective and efficient.

3. FAC-002-1 R2 has a Lower VRF.

4. FAC-002-1 R2 is in the third tier of the AML.

5. The retirement of FAC-002-1 R2 does not pose any negative impact to NERC's published and posted reliability principles, since there are no directly applicable reliability principles.

6. The retirement does not negatively impact defense in depth because the compilation of studies for three years has no operational or planning relationship with any other requirement.

7. The retirement of FAC-002-1 R2 promotes a results-based approach since the requirement is administrative and data collection, and, therefore, does not provide the foundation for performing a reliability task.

Accordingly, for the above reasons, it is appropriate to retire FAC-002-1 R2.

FAC-008-1 R2; FAC-008-1 R3;[53] - Facility Ratings Methodology

R2. The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.

R3. If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

Background/Commission Directives
FAC-008-1 was submitted for Commission approval on April 4, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[54]

There are no outstanding Commission directives that are affected by the proposed retirement of FAC-008-1 R2 and R3.

[53] Unlike the other requirements presented for informational purposes only, FAC-008-1 R2 and FAC-008-1 R3 have been maintained within the scope of P81 given that they are essentially identical to FAC-008-3 R4; FAC-008-3 R5 which are due be effective on January 1, 2013. Inclusion would also appear to be consistent with increasing ERO compliance program efficiencies, given that retirement would exempt these requirements from being included in spot checks or compliance audits that are backward looking via FAC-008-1 R2 and R3.

[54] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

Technical Justification

FAC-008-1 R2 and R3 require that a Transmission Owner and Generator Owner must make its facilities ratings methodology available for inspection and technical review by Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated facilities are located and also require them to respond to any comments received including whether a change will be made to the facility ratings methodology. The retirement of FAC-008-1 R2 and R3 does not create a reliability gap, because Transmission Owners and Generator Owners must comply with the substantive requirements of FAC-008-1 regarding their facility rating methodologies whether or not the exchange envisioned by FAC-008-1 R2 and R3 occurs. Furthermore, neither FAC-008-1 R2 and R3 require that the Transmission Owner and Generator Owner change its methodology, rather FAC-008-1 R2 and R3 are designed as an exchange of comments that may be an avenue to advance commercial interests.

For example, if a Generator Owner's methodology provides for derating its generator step up ("GSU") transformers below the nameplate in an effort to extend the life of its GSUs, that is a commercial decision it has made, and should not be subject to review by a Reliability Coordinator, Transmission Operator, Transmission Planner, and Planning Authority, some of which may have affiliated parts of their company that could benefit from the Generator Owner changing its methodology and operating its GSUs at nameplate. In contrast, the reliability objective that facility ratings produced by the methodologies of the Transmission Owner or Generator Owner shall equal the most limiting applicable equipment rating, and consider, for example, emergency and normal conditions, operating conditions, nameplate ratings, etc. is not significantly or substantively advanced by FAC-008-1 R2 (available for inspection) and R3 (comment and responsive comments). Furthermore, the reliability objective that facility ratings produced by the methodologies of the Transmission Owner or Generator Owner are provided to the reliability entities for the establishment of System Operating Limits ("SOLs"), Interconnection Reliability Operating Limits ("IROLs"), calculations for MOD requirements and compliance with the TPL Standards is accomplished without FAC-008-1 R2 (available for inspection) and R3 (comment and responsive comments).[55] Accordingly, the requirements in FAC-008-1 R2 and FAC-008-1 R3 to make the facility ratings methodology available for comment (and if comments are received to respond to those comments) is an administrative task that does little, if anything, to benefit or protect the reliable operation of the BES, and has the potential to implicate commercially sensitive issues. (Criteria A, B1, B4 and B6). In this context, it would seem unnecessarily burdensome to engage in the exchange of comments, given there is no nexus between the exchange of comments and compliance with the substantive

[55] See MOD-001-1a R9, MOD-028-1 R2.3; MOD-029-1a R2.1; MOD-030-02 R3.1, PRC-023-2, Attachment A 2.7; TPL-001-0.1 Footnote a; TPL-002-1b, footnotes a and b; TPL-003-0a, footnote a and TPL-004-0, footnote a. Also, via FAC-011-2 the System Operating Limits methodology of Reliability Coordinator may also use facility ratings as a key element.

requirements of FAC-008-1. Instead of spending time and resources on FAC-008-1 R2 and R3, Generator Owners' and Transmission Owners' time and resources would be better spent complying with the substantive requirements of FAC-008-1. For these same reasons, the ERO compliance program would gain efficiencies by no longer having to track whether requests for technical review had occurred, comments provided and reallocate time and resources to monitoring the Transmission Owner's or Generator Owner's adherence to substantive requirements of FAC-008-1.

Criterion A

The requirements in FAC-008-1 R2 and R3 to make the facility ratings methodology available for comment (and if comments are received to respond to those comments) is an administrative task that does little, if anything, to benefit or protect the reliable operation of the BES, and has the potential to implicate commercially sensitive issues.

Criteria B

- Criterion B1 (Administrative)
- Criterion B4 (Reporting)
- Criterion B6 (Commercial or Business Practice)

Criteria C

1. FAC-008-1 R2 and R3 have not been part of a FFT filing.

2. FAC-008-1 R2 and R3 are not subject to an on-going Standards Development Project.

3. FAC-008-1 R2 and R3 have a Lower VRF.

4. FAC-008-1 R2 and R3 are in the third tier of the AML.

5. The retirement of FAC-008-1 R2 and R3 does not pose any negative impact to the following applicable NERC's published and posted reliability principles:

   Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

   Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

   It is the adherence to the substantive requirements of FAC-008-1 that promotes these posted reliability principles, and not receiving comments on the facility

ratings methodology from outside entities and then responding to those comments.

6. Retirement of FAC-008-1 R2 and R3, does not negatively impact defense in depth because no other requirement depends on it to help cover a reliability gap or risk to reliability. These requirements may invite entities to engage in an exchange or debate over commercially sensitive information.

7. The retirement of FAC-008-1 R2 and R3 promotes a results-based approach because the requirements do not require the performance of a reliability task.

Accordingly, for the above reasons, it is appropriate to retire FAC-008-1 R2 and R3.

FAC-008-3 R4; FAC-008-3 R5 – Facility Ratings

R4. Each Transmission Owner shall make its Facility Ratings methodology and each Generator Owner shall each make its documentation for determining its Facility Ratings and its Facility Ratings methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners and Planning Coordinators that have responsibility for the area in which the associated Facilities are located, within 21 calendar days of receipt of a request.

R5. If a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Coordinator provides documented comments on its technical review of a Transmission Owner's Facility Ratings methodology or Generator Owner's documentation for determining its Facility Ratings and its Facility Rating methodology, the Transmission Owner or Generator Owner shall provide a response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings methodology and, if no change will be made to that Facility Ratings methodology, the reason why.

Background/Commission Directives

FAC-008-1 was submitted for Commission approval on April 4, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[56] "On May 12, 2010, the NERC Board of Trustees approved the proposed FAC-008-2 Reliability Standard that addressed the first two of the FERC directives in Order No. 693. NERC's proposed FAC-008-2 Reliability Standard was not filed with FERC for approval, but instead was revisited by the standard drafting team so that the third Order

[56] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

No. 693 directive could be addressed in response to FERC's March 18, 2010 Order…"[57] FAC-008-3 was submitted for Commission approval on June 15, 2011 in Docket No. RD11-10-000 and was approved on November 17, 2011.[58]

There are no outstanding Commission directives that are affected by the proposed retirement of FAC-008-3 R4 and R5.

Technical Justification

FAC-008-3 R4 and R5 require that a Transmission Owner and Generator Owner must make its facilities ratings methodology available for inspection and technical review by Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated facilities are located and also require them to respond to any comments received including whether a change will be made to the facility ratings methodology. The retirement of FAC-008-3 R4 and R5 does not create a reliability gap, because Transmission Owners and Generator Owners must comply with the substantive requirements of FAC-008-3 regarding their facility rating methodologies whether or not the exchange envisioned by FAC-008-3 R4 and R5 occurs. Further, neither FAC-008-3 R4 nor R5 require that the Transmission Owner and Generator Owner change its methodology, rather FAC-008-3 R4 and R5 are designed as an exchange of comments that may be an avenue to advance commercial interests.

For example, if a Generator Owner's methodology provides for derating its GSU transformers below the nameplate in an effort to extend the life of its GSUs, that is a commercial decision it has made, and should not be subject to review by a Reliability Coordinator, Transmission Operator, Transmission Planner, and Planning Authority, some of which may have affiliated parts of their company that could benefit from the Generator Owner changing its methodology and operating its GSUs at nameplate. In contrast, the reliability objective that facility ratings produced by the methodologies of the Transmission Owner or Generator Owner shall equal the most limiting applicable equipment rating, and consider, for example, emergency and normal conditions, historical performance, nameplate ratings, etc. is not significantly or substantively advanced by FAC-008-3 R4 (available for inspection) and R5 (comment and responsive comments). Furthermore, the reliability objective that facility ratings produced by the methodologies of the Transmission Owner or Generator Owner are provided to the reliability entities for the establishment of SOLs, IROLs, calculations for MOD requirements and compliance with the TPL Standards is accomplished without FAC-008-3 R4 (available for inspection) and R5 (comment and responsive comments).[59] Accordingly, the

[57] Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard FAC-008-3 — Facility Ratings, Docket No. RD11-10-000, (June 15, 2011).
[58] *Order Approving Reliability Standard*, 137 FERC ¶ 61,123 (2011).
[59] See MOD-001-1a R9, MOD-028-1 R2.3; MOD-029-1a R2.1; MOD-030-2 R3.1, PRC-023-2, Attachment A 2.7; TPL-001-0.1 Footnote a; TPL-002-1b, footnotes a and b; TPL-003-0a, footnote a and TPL-004-0, footnote a. Also, via FAC-011-2 the System Operating Limits methodology of Reliability Coordinator may

requirements in FAC-008-3 R4 and R5 to make the facility ratings methodology available for comment (and if comments are received to respond to those comments) is an administrative task that does little, if anything, to benefit or protect the reliable operation of the BES, and has the potential to implicate commercially sensitive issues. (Criteria A, B1, B4 and B6). In this context, it would seem unnecessarily burdensome to engage in the exchange of comments, given there is no nexus between the exchange and compliance with the substantive requirements of FAC-008-3. Instead of spending time and resources on FAC-008-3 R4 and R5, Generator Owners' and Transmission Owners' time and resources would be better spent complying with the substantive requirements of FAC-008-3. For these same reasons, the ERO compliance program would gain efficiencies by no longer having to track whether requests for technical review had occurred, comments provided and reallocate time and resources to monitoring the Transmission Owner's or Generator Owner's adherence to substantive requirements of FAC-008-3.

Criterion A

The requirements in FAC-008-3 R4 and R5 to make the facility ratings methodology available for comment (and if comments are received to respond to those comments) is an administrative task that does little, if anything, to benefit or protect the reliable operation of the BES, and has the potential to implicate commercially sensitive issues.

Criteria B

- Criterion B1 (Administrative)
- Criterion B4 (Reporting)
- Criterion B6 (Commercial or Business Practice)

Criteria C

1. FAC-008-3 R4 and R5 have not been part of a FFT filing.

2. FAC-008-3 R4 and R5 are not subject to an on-going Standards Development Project.

3. FAC-008-3 R4 and R5 have a Lower VRF.

4. FAC-008-3 R4 and R5 are in the third tier of the AML.

5. The retirement of FAC-008-3 R4 and R5 does not pose any negative impact to the following applicable NERC's published and posted reliability principles:

   Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under

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also use facility ratings as a key element. Also, FAC-008-3 R7 and R8 require the transmission of facility ratings to reliability entities.

normal and abnormal conditions as defined in the NERC Standards.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

It is the adherence to the substantive requirements of FAC-008-3 that promotes these posted reliability principles, and not receiving comments on the facility ratings methodology from outside entities and then responding to those comments.

6. Retirement of FAC-008-3 R4 and R5, does not negatively impact defense in depth because no other requirement depends on it to help cover a reliability gap or risk to reliability. These may invite entities to engage in an exchange or debate over commercially sensitive information.

7. The retirement of FAC-008-3 R4 and R5 promotes a results-based approach because the requirements do not require the performance of a reliability task.

Accordingly, for the above reasons, it is appropriate to retire FAC-008-3 R4 and R5.

****FAC-010-2.1 R5 – System Operating Limits Methodology for the Planning Horizon**

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

Background/Commission Directives

FAC-010-1 was filed for Commission approval on November 15, 2006 in Docket Nos. RM06-16-000 and RM07-3-000 and was approved on December 27, 2007 in Order No. 705.[60] FAC-010-2 was filed for Commission approval on June 30, 2008 in Docket No. RM08-11-000 and was approved on March 20, 2009 in Order No. 722.[61] FAC-010-2.1 was filed for Commission approval on November 20, 2009 in Docket No. RD10-9-000

[60] *Facilities Design, Connections and Maintenance Reliability Standards,* 121 FERC ¶ 61,296 (December 27, 2007) (Order No. 705).

[61] *Version Two Facilities Design, Connections and Maintenance Reliability Standards,* 126 FERC ¶ 61,255 (March 20, 2009) (Order No. 722).

and was approved on April 19, 2010.[62] In Order No. 722,[63] the Commission approved FAC-010-2.1 R5 without specifically addressing R5.

There are no outstanding Commission directives with respect to this R5.

Technical Justification

The reliability purpose of FAC-010-2.1, to ensure that System Operating Limits used in the reliable planning of the BES are determined based on an established methodology, is unaffected by the proposed retirement of R5. FAC-010-2.1 R5 requires that when a Planning Authority receives comments on its SOL methodology, it must respond and indicate whether it has changed its methodology. The retirement of FAC-010-2.1 R5 does not create a reliability gap, because the Planning Authority must comply with the substantive requirements of FAC-010-2.1 whether or not the exchange envisioned by FAC-010-2.1 R5 occurs. FAC-010-2.1 R5 may support an avenue to advance commercial interests.

For example, if a Transmission Operator or Transmission Planner is also a Transmission Owner it may have a commercial interest in lowering SOLs on its transmission lines in an effort to extend the life of its equipment and, therefore, challenge the Planning Authority's methodology to reduce its SOLs. The Transmission Owner's interests are better considered in the context of its development of a facility ratings methodology under FAC-008-1, -3 than the Planning Authority's methodology. FAC-010-2.1 R5, however, is an invitation to advance commercial interests not through established means, but by challenging the Planning Authority's SOL methodology. Accordingly, FAC-010-2.1 R5 sets forth an administrative task that does little, if anything, to benefit or protect the reliable operation of the BES, and has the potential to implicate commercially sensitive issues. (Criteria A, B1, B4 and B6). In this context, it would seem unnecessarily burdensome to engage in the exchange of comments, given there is no nexus between the exchange and compliance with the substantive requirements of FAC-010-2.1. Instead of spending time and resources on FAC-010-2.1, a Planning Authority's time and resources would be better spent complying with the substantive requirements of FAC-010-2.1. For these same reasons, the ERO compliance program would gain efficiencies by no longer having to track whether requests for technical review had occurred, comments provided and reallocate time and resources to monitoring the Planning Authority's adherence to substantive requirements of FAC-010-2.1.

Criterion A

The requirement in FAC-010-2.1 R5 to respond to comments on the SOL methodology is an administrative task that does little, if anything, to benefit or protect the reliable operation of the BES.

[62] Letter Order, Electric Reliability Organization Errata Petition Updating Accepted Transmission Operations Reliability Standards, Docket No. RD10-9-000 (April 19, 2010).

[63] *Version Two Facilities Design, Connections and Maintenance Reliability Standards* 125 FERC ¶ 61,040 (2009).

Criteria B

- Criterion B1 (Administrative)
- Criterion B4 (Reporting)
- Criterion B6 (Commercial or Business Practice)

Criteria C

1. FAC-010-2.1 R5 has not been part of a FFT filing.

2. FAC-010-2.1 R5 is subject to future Standards Development Project 2012-11 FAC Review, which is a placeholder for the five year review of FAC-010 and FAC-011. Thus, it is appropriate to process the retirement of this requirement as part of the P81 Project.

3. FAC-010-2.1 R5 has a Lower VRF.

4. FAC-010-2.1 R5 is not on the AML.

5. The retirement of this requirement does not pose any negative impact to NERC's published and posted reliability principles No. 1 or No. 3.

   Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

   Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

   It is the adherence to the substantive requirements of FAC-010-2.1 that promotes these posted reliability principles, and not receiving comments on the facility ratings methodology from outside entities and then responding to those comments.

6. The retirement of this requirement does not negatively impact defense in depth because no other requirement depends on it to help cover a reliability gap or risk to reliability.

7. The retirement of FAC-010-2.1 R5 also promotes a results-based approach because the requirements have no direct nexus to the performance of a reliability task.

Accordingly, for the above reasons, it is appropriate to retire FAC-010-2.1 R5.

****FAC-011-2 R5– System Operating Limits Methodology for the Operations Horizon**

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

Background/Commission Directives

FAC-011-1 was filed for Commission approval on November 15, 2006 in Docket Nos. RM06-16-000 and RM07-3-000 and was approved on December 27, 2007 in Order No. 705.[64] FAC-011-2 was filed for Commission approval on June 30, 2008 in Docket No. RM08-11-000 and was approved on March 20, 2009 in Order No. 722.[65] In Order No. 722, the Commission approved FAC-011-2 R5 without specifically addressing R5.

There are no outstanding Commission directives with respect to this R5.

Technical Justification

FAC-011-2 R5 requires that when a Reliability Coordinator receives comments on its SOL methodology that it must respond and indicate whether it has changed its methodology. The retirement of FAC-011-2 R5 does not create a reliability gap, because the Reliability Coordinator must comply with the substantive requirements of FAC-011-2 R5 whether or not the exchange envisioned by FAC-011-2 R5 occurs. FAC-011-2 R5 may support an avenue to advance commercial interests.

For example, similar to FAC-010-2.1 R5, if a Transmission Operator or Transmission Planner also is a Transmission Owner it may have a commercial interest in lowering SOLs on its transmission lines in an effort to extend the life of its equipment and, therefore, challenge the Reliability Coordinator's methodology to reduce its SOLs. The Transmission Owner's interests are better considered in the context of the development of its facility ratings methodology under FAC-008-1, -3 than the Reliability Coordinator's methodology. FAC-011-2 R5, however, is an invitation to advance commercial interests not through established means, but by challenging the Reliability Coordinator's SOL methodology. Accordingly, FAC-011-2 R5 sets forth an administrative task that does little, if anything, to benefit or protect the reliable operation of the BES, and has the potential to implicate commercially sensitive issues. (Criteria A, B1, B4 and B6). In

[64] *Facilities Design, Connections and Maintenance Reliability Standards,* 121 FERC ¶ 61,296 (December 27, 2007) (Order No. 705).

[65] *Version Two Facilities Design, Connections and Maintenance Reliability Standards,* 126 FERC ¶ 61,255 (March 20, 2009) (Order No. 722).

this context, it would seem unnecessarily burdensome to engage in the exchange of comments, given there is no nexus between the exchange and compliance with the substantive requirements of FAC-011-2. Instead of spending time and resources on FAC-011-2 R5 a Reliability Coordinator's time and resources would be better spent complying with the substantive requirements of FAC-011-2 R5. For these same reasons, the ERO compliance program would gain efficiencies by no longer having to track whether requests for technical review had occurred, comments provided and reallocate time and resources to monitoring the Reliability Coordinator's adherence to substantive requirements of FAC-011-2 R5.

Criterion A
The requirement in FAC-011-2 R5 to respond to comments on the SOL methodology is an administrative task that does little, if anything, to benefit or protect the reliable operation of the BES, and has the potential to implicate commercially sensitive issues.

Criteria B
- Criterion B1 (Administrative)
- Criterion B4 (Reporting)
- Criterion B6 (Commercial or Business Practice)

Criteria C
1. FAC-011-2 R5 has not been part of a FFT filing.

2. FAC-011-2 R5 is subject to future Standards Development Project 2012-11 FAC Review, which is a placeholder for the five year review of FAC-010 and FAC-011which is not currently scheduled and thus it is appropriate to process the retirement of this requirement as part of the P81 Project.

3. FAC-011-2 R5 has a Lower VRF.

4. FAC-011-2 R5 is not on the AML.

5. The retirement of this requirement does not pose any negative impact to NERC's published and posted reliability principles No. 1 or No. 3.

   Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

   Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

> It is the adherence to the substantive requirements of FAC-011-2 that promotes these posted reliability principles, and not receiving comments on the facility ratings methodology from outside entities and then responding to those comments.

6. The retirement of this requirement does not negatively impact defense in depth because no other requirement depends on it to help cover a reliability gap or risk to reliability.

7. The retirement of FAC-011-2 R5 also promotes a results-based approach because the requirements have no direct nexus to the performance of a reliability task.

Accordingly, for the above reasons, it is appropriate to retire FAC-011-2 R5.

FAC-013-2 R3 – Assessment of Transfer Capability for the Near-term Transmission Planning Horizon

> **R3.** If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why.

Background/Commission Directives

FAC-013-1 was submitted for Commission approval on April 4, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[66] FAC-013-2 was submitted for Commission approval on January 28, 2011 in Docket No. RD11-3-000 and was approved on November 17, 2011.[67]

In Order No. 729, the Commission denied NERC's request to withdraw FAC-012-1 and retire FAC-013-1, and directed as follows at paragraph 291:

> 291. The Commission hereby adopts its NOPR proposal to deny NERC's request to withdraw FAC-012-1 and retire FAC-013-1. Instead, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop modifications to FAC-012-1 and FAC-013-1 to comply with the relevant directives of Order No. 693 and, as otherwise necessary, to make the requirements of those Reliability Standards consistent with those of the MOD Reliability Standards approved herein as well as this Final Rule. These

[66] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[67] *Order Approving Reliability Standard*, 137 FERC ¶ 61,131 (2011).

> modifications should also remove redundant provisions for the calculation of transfer capability addressed elsewhere in the MOD Reliability Standards. In making these revisions, the ERO should consider the development of a methodology for calculation of inter-regional and intra-regional transfer capabilities. The Commission accepts the ERO's request for additional time to prepare the modifications and so directs the ERO to submit the modifications to FAC-012-1 and FAC-013-1 no later than 60 days before the MOD Reliability Standards become effective.

Although the Commission did not directly address the merits of FAC-013-2 R3 when approving FAC-013-2,[68] similar to FAC-008-3, the developer of the Transfer Capability methodology and data must follow specific technical requirements and provide the data to reliability entities for use in their models. There are no outstanding Commission directives with respect to this R3.

Technical Justification

A review of FAC-013-2 R3 indicates that it is a needlessly burdensome administrative task that does little, if anything, to benefit or protect the reliable operation of the BES. (Criteria A, B1 and B4). Specifically, FAC-013-2 R1 and its sub-requirements set forth the information that each Planning Authority must include when developing its Transfer Capability methodology. FAC-013-2 R3 sets forth a requirement that if an entity comments on this methodology, the Planning Authority must respond and indicate whether or not it will make a change to its Transfer Capability methodology. Thus, while R1 sets forth substantive requirements, R3 sets forth more of an administrative task of the Planning Authority responding to comments on its methodology.

The following NERC glossary definition of Transfer Capability states:

> The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is *not g*enerally equal to the transfer capability from "Area B" to "Area A."

In the context of a Planning Authority engaging in an exchange with an entity over the Transfer Capability there is a possibility of a scenario that a group of generators[69] try to get the Planning Authority to revise its Transfer Capability methodology to advance commercial interests via changes to the methodology that would increase or decrease transfer capability from Area A to Area B. (Criterion B6). Such issues should be raised

[68] *Id.* (approval of FAC-013-2).

[69] Generators that receive the Transfer Capability methodology via an association with one of the entities in the R2 sub-requirements.

in the context of receipt of transmission services, not the Reliability Standards. Moreover, even without the possible commercial motivation of certain entities to get the Planning Authority to revise its Transfer Capability methodology, implementing an exchange between entities and the Planning Authority seems much better suited via regional planning committees, than mandatory Reliability Standards.

In this context, it would seem unnecessarily burdensome to engage in the exchange of comments, given there is no nexus between the exchange and compliance with the substantive requirements of FAC-013-2. Instead of spending time and resources on FAC-013-2 R3, time and resources would be better spent complying with the substantive requirements of FAC-013-2. For these same reasons, the ERO compliance program would gain efficiencies by no longer having to track whether requests for technical review had occurred, comments provided and reallocate time and resources to monitoring the Reliability Coordinator's adherence to substantive requirements of FAC-013-2.

Criterion A
The requirement in FAC-013-2 R3 to respond to comments on the Transfer Capability methodology is an administrative task that does little, if anything, to benefit or protect the reliable operation of the BES, and has the potential to implicate commercially sensitive issues.

Criteria B
- Criterion B1 (Administrative)
- Criterion B4 (Reporting)
- Criterion B6 (Commercial or Business Practice)

Criteria C
1. FAC-013-2 R3 has not been part of a FFT filing.

2. FAC-013-2 R3 is not subject to an on-going Standards Development Project.

3. FAC-013-2 R3 has a Lower VRF.

4. FAC-013-2 R3 is not on the AML.

5. The retirement of FAC-013-2 R3 does not pose any negative impact to NERC's published and posted reliability principles No. 1 or No. 3.

   Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

It is the adherence to the substantive requirements of FAC-013-2 that promotes these posted reliability principles, and not receiving comments on the facility ratings methodology from outside entities and then responding to those comments.

6. The retirement of FAC-013-2 R3 does not negatively impact defense in depth because no other requirement depends on it to help cover a reliability gap or risk to reliability.

7. The retirement of FAC-013-2 R3 promotes a results-based approach because the requirements do not require the performance of a reliability task.

Accordingly, for the above reasons, it is appropriate to retire FAC-013-2 R3.

INT-007-1 R1.2 – Interchange Confirmation

R1.2. All reliability entities involved in the Arranged Interchange are currently in the NERC registry.

Background/Commission Directives
INT-007-1 was submitted for Commission approval on August 28, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[70] The Commission did not directly address INT-007-1 R1.2 when it approved the Reliability Standard in Order No. 693 at paragraph 867.

There are no outstanding Commission directives with respect to R1.2.

Technical Justification
The reliability purpose of INT-007-1 is to ensure that each Arranged Interchange is checked for reliability before it is implemented. The reliability purpose of INT-007-1 is unaffected by the proposed retirement of R1.2.

INT-007-1 R1.2 is a needlessly burdensome administrative task that does not support reliability because it is now outdated. (Criterion B1). At one time the identification number came from the NERC TSIN system, by now it is handled via NAESB Electric

[70] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

Industry Registry.[71] Also, under the E-Tag protocols, no entity may engage in an Interchange transaction without first registering with the E-Tag system and receiving an identification number. Further, the entity desiring the transaction enters this identification number in the E-Tag system to pre-qualify and engage in an Arranged Interchange. Accordingly, the task set forth in INT-007-1 R1.2 is an outdated activity that is no longer necessary, and thus, does little, if anything, to benefit or protect the reliable operation of the BES. (Criterion A). The ERO compliance program would benefit and be more efficient if it was not monitoring an outdated requirement.

Criterion A
The task set forth in INT-007-1 R1.2 is an outdated activity that is no longer necessary, and thus, does little, if anything, to benefit or protect the reliable operation of the BES.

Criteria B

- Criterion B1 (Administrative)

Criteria C

1. INT-007-1 R1.2 has not been part of a FFT filing.

2. INT-007-1 R1.2 is part of a pending Standards Development Project – Project 2008-12 Coordinate Interchange Standards, which is estimated to start in the second quarter of 2013. Given this timeline, it is appropriate to move forward with the retirement of INT-007-1 R1.2. Such a retirement may also help to streamline Project 2008-12 once it is active and progressing.

3. INT-007-1 R1.2 has a Lower VRF.

4. INT-007-1 R1.2 is not on the AML.

5. The retirement of INT-007-1 R1.2 does not pose any negative impact to NERC's published and posted reliability principles No. 1 or No. 3.

    Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

    Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

[71] *See, North American Energy Standards Board Webregistry Technical Guide v1.4* (Proprietary) (July 2012). The new NAESB system has updated and implemented more automation to the process.

It is the adherence to the substantive requirements of INT-007-1 that promotes these posted reliability principles, not R1.2.

6. The retirement of INT-007-1 R1.2 does not impact any defense in depth strategies because the task is no longer necessary.

7. The retirement of INT-007-1 R1.2 promotes a results-based approach because the requirement does not require the performance of a reliability task.

Accordingly, for the above reasons, it is appropriate to retire INT-007-1 R1.2.

IRO-016-1 R2 – Coordination of Real-time Activities Between Reliability Coordinators

R2. The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.

Background/Commission Directives
IRO-016-1 was submitted for Commission approval on April 4, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693. The Commission did not directly address R2 when approving IRO-016-1 in Order No. 693 at paragraphs 1004 and 1005. There are no outstanding Commission directives with respect to R2.

Technical Justification
The reliability purpose of IRO-016-1 is to ensure that each Reliability Coordinator's operations are coordinated such that they will not have an adverse reliability impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations. To implement the purpose, IRO-016-1 R1 and its sub-requirements state:

> **R1.** The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.
>
> **R1.1.** If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken.

> **R1.2.** If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.).
>
> **R1.2.1.** If time permits, this re-evaluation shall be done before taking corrective actions.
>
> **R1.2.2.** If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved.

These requirements are specific actions and decision points among Reliability Coordinators that promote the reliable operation of the BES. In contrast, a review of R2 indicates that it is a needlessly burdensome administrative and data collection requirement that does little, if anything, to benefit or protect the reliable operation of the BES. (Criteria A, B1 and B2). Therefore, the reliability purpose of IRO-016-1 is unaffected by the proposed retirement of R2.

Furthermore, outside the context of a Reliability Standard, under Section 400 of the NERC Rules of Procedure, NERC and the Regional Entities have the authority to require an entity to submit data and information for purposes of monitoring compliance. Thus, the retirement of IRO-016-1 R2 does not affect the ability for NERC and the Regional Entities to require Reliability Coordinators to produce documentation to demonstrate compliance with IRO-016-1 R1 and its sub-requirements. Accordingly, retiring IRO-016-1 R2 presents no gap to reliability or to the information NERC and the Regional Entities need to monitor compliance. Thus, IRO-016-1 R1 does not support reliability. Consequently, R2 is an administrative and data collection requirement that that does little, if anything, to benefit or protect the reliable operation of the BES. (Criteria A, B1 and B2). Also, there are some inherent inefficiencies that result by a small number of requirements, such as IRO-016-1 R2 being a data, evidence and record retention requirement, while there are other and more appropriate established methods to collect and review the data than a Reliability Standard via Rules of Procedure Section 401. In this regard, for the ERO, Regional Entities and the entities, arguably Reliability Standards are more difficult to understand because of this inconsistent approach (typically only implicitly requiring documentation as a part of an obligation to prove compliance, but occasionally explicitly requiring it with no discernible pattern or rationale).

Criterion A
A review of R2 indicates that it is a needlessly burdensome administrative and data collection requirement that does little, if anything, to benefit or protect the reliable operation of the BES.

Criteria B

- Criterion B1 (Administrative)

- Criterion B2 (Data Collection/Data Retention)

Criteria C

1. IRO-016-1 R2 has not been part of a FFT filing

2. IRO-016-1 R2 is not subject to an on-going Standards Development project.

3. IRO-016-1 R2 has a Lower VRF.

4. IRO-016-1 R2 is not on the AML.

5. The retirement of IRO-016-1 R2 does not pose any negative impact to NERC's published and posted reliability principles, since none of the principles appear to apply to a data retention requirement.

6. IRO-016-1 R2 does not negatively impact defense in depth because no other requirement depends on it to help cover a reliability gap or risk to reliability.

7. The retirement of IRO-016-1 R2 promotes a results-based approach because the requirement is administrative and data collection, and, therefore, does not provide the foundation for performing a reliability task.

Accordingly, for the above reasons, it is appropriate to retire IRO-016-1 R2.

NUC-001-2 R9.1; NUC-001-2 R9.1.1; NUC-001-2 R9.1.2; NUC-001-2 R9.1.3; NUC-001-2 R9.1.4 – Nuclear Plant Interface Coordination

R9.1. Administrative elements:

R9.1.1. Definitions of key terms used in the agreement.

R9.1.2. Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs.

R9.1.3. A requirement to review the agreement(s) at least every three years.

R9.1.4. A dispute resolution mechanism.

Background/Commission Directives

NUC-001-1 was submitted for Commission approval on November 19, 2007 in Docket No. RM08-3-000 and was approved on October 16, 2008.[72] NUC-001-2 was submitted

[72] *Mandatory Reliability Standard for Nuclear Plant Interface Coordination*, 125 FERC ¶ 61,065 (2008) ("Order No. 716"), *order on reh'g*, Order No. 716-A, 126 FERC ¶ 61,122 (2009).

for Commission approval on August 14, 2009 in Docket No. RD09-10-000 and was approved on January 21, 2010.[73]

Although in Order No. 716 the merits of R9.1 and its sub-requirements were not directly addressed, the Commission did state the following in the context of the VRFs for all of R9:[74]

> Consistent with the NOPR, the Commission directs the ERO to revise the violation risk factor assignment for Requirement R9 from lower to medium. The Commission disagrees with commenters that a lower violation risk factor is appropriate because Requirement R9 is an administrative requirement to include the specified provisions. While the Commission recognized in the NOPR that many of the requirements of the proposed Reliability Standard are administrative in nature, these same requirements provide for the development of procedures to ensure the safe and reliable operation of the grid, and responses to potential emergency conditions.

There are no outstanding Commission directives with respect to these requirements.

Technical Justification

The reliability purpose of NUC-001-2 is to ensure the coordination between Nuclear Plant Generator Operators and Transmission Entities for nuclear plant safe operation and shutdown. The reliability purpose of NUC-001-2 is unaffected by the proposed retirement of requirements 9.1, 9.1.1, 9.1.2, 9.1.3 and 9.1.4. Requirement 9.1 and its sub-requirements specify certain administrative elements that must be included in the agreement (required by R2) between the Nuclear Plant Generator Operator and the applicable Transmission Entities. These are a mix of technical, communication, training and administrative requirements. Of those that may be classified as administrative, R9.1 and its sub-requirements clearly stand out as unnecessarily burdensome administrative tasks that do little, if anything, to benefit or protect the reliable operation of the BES. (Criteria A and B1). R9.1 and its sub-requirements are a check list of certain non-technical boilerplate provisions generally included in modern agreements. These provisions do not directly relate to protecting BES reliability. Further, requiring via a mandatory Reliability Standard the inclusion of boilerplate provisions is an unnecessarily burdensome relative to the other significant requirements in NUC-001-2 that pertain to performance based reliability coordination and protocols between Transmission Entities and Nuclear Plant Generator Operators. Therefore, the retirement of NUC-001-2 R9.1 and all its sub-requirements creates no reliability gap and are the type of provisions that would likely be in a modern agreement anyway.

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[73] *Order Approving Reliability Standard*, 130 FERC ¶ 61,051 (2010).

[74] NUC-001-1 was approved in Order No. 716, while NUC-001-2 was approved without discussion of R9.1 and its sub-requirements in a subsequent order. *Mandatory Reliability Standard for Nuclear Plant Interface Coordination*, 125 FERC ¶ 61,065 (2008); 130 FERC ¶ 61,051 (2010).

For these same reasons, the ERO compliance program efficiency will increase with the retirement of NUC-001-2 R9.1 and its sub-requirements because compliance monitoring time and resources will not be spent conducting a checklist of whether an agreement includes boilerplate provisions, and instead, the time and resources may be spent reviewing adherence with the technical, substantive coordination and protocol provisions of NUC-001-2.

Criterion A
R9.1 and its sub-requirements are unnecessarily burdensome administrative tasks that do little, if anything, to benefit or protect the reliable operation of the BES.

Criteria B
- Criterion B1 (Administrative)

Criteria C
1. NUC-001-2 R9.1 and its sub-requirements have not been part of a FFT filing.

2. NUC-001-2 R9.1 and its sub-requirements are not part of an on-going Standards Development Project, but NUC-001-2 is part of Project 2012-13, which is a placeholder for a five year review. Given the as yet undetermined start date for Project 2012-13, it is appropriate to move forward with the retirement of NUC-001-2 R9.1 and its sub-requirements.

3. Individual VRFs are not assigned to the sub-requirements of NUC-001-2 R9.

4. NUC-001-2 R9.1 and its sub-requirements are in the third tier of the AML.

5. The retirement of NUC-001-2 R9.1 and its sub-requirements do not pose any negative impact to NERC's published and posted reliability principles, since none of them seem to apply to the inclusion of boilerplate contractual provisions.

6. There is no impact on a defense in depth strategy because no other requirement depends on it to help cover a reliability gap or risk to reliability.

7. The retirement of NUC-001-2 R9.1 and its sub-requirements promote a results-based approach by eliminating administrative check-list requirements.

Accordingly, for the above reasons, it is appropriate to retire NUC-001-2 R9.1 and its sub-requirements.

PRC-010-0 R2 – Assessment of the Design and Effectiveness of UVLS Program;

R2. The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide

> documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days).

Background/Commission Directives

PRC-010-0 was filed for Commission approval on April 4, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[75] Although not specifically addressing PRC-010-0 R2, in Order No. 693 at paragraph 1506 and 1507 the Commission stated that:

> With regard to ISO-NE's disagreement on integration of various system protections "because such integration cannot be technologically accomplished", we note that the evidence collected in the Blackout Report indicates that "the relay protection settings for the transmission lines, generators and underfrequency load shedding in the northeast may not be entirely appropriate and are certainly not coordinated and integrated to reduce the likelihood and consequence of a cascade – nor were they intended to do so." In addition, the Blackout Report stated that one of the common causes of major outages in North America is a lack of coordination on system protection. The Commission agrees with the protection experts who participated in the investigation, formulated Blackout Recommendation No. 21 and recommended that UVLS programs have an integrated approach.
>
> Regarding FirstEnergy's question of whether universal coordination among UVLS programs that address local system problems makes sense, we believe that PRC-010-0's objective in requiring an integrated and coordinated approach is to address the possible adverse interactions of these protection systems among themselves and to determine whether they could aggravate or accelerate cascading events. We do not believe this Reliability Standard is aimed at universal coordination among UVLS programs that address local system problems. (Footnote omitted).

The retirement of PRC-010-0 R2 does not affect a Commission directive.

Technical Justification

Outside the context of a Reliability Standard, under Section 400 of the NERC Rules of Procedure, NERC and the Regional Entities have the authority to require an entity to submit documentation of its current UVLS program assessment for purposes of monitoring compliance. Thus, the retirement of PRC-010-0 R2 does not affect the ability of NERC and the Regional Entities to require Reliability Coordinators to produce documentation to monitor compliance with PRC-010-0 R1 and its sub-requirements.

[75] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

Furthermore, PRC-010-0 R1 requires that the entity document an assessment of the effectiveness of its UVLS program:

> The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall periodically (at least every five years or as required by changes in system conditions) conduct and document an assessment of the effectiveness of the UVLS program.

Accordingly, retiring PRC-010-0 R2 presents no gap to reliability or to the information NERC and the Regional Entity need to monitor compliance. A review of R2 indicates that it is a needlessly burdensome administrative and data collection/retention requirement that does little, if anything, to benefit or protect the reliable operation of the BES. (Criteria A, B1 and B2). Also, there are some inherent inefficiencies that result by a small number of requirements, such as PRC-010-0 R2 being a data production requirement, while there are other and more appropriate established methods to collect and review the data than a Reliability Standard via Rules of Procedure Section 401.

Criterion A
R2 is an administrative and data collection requirement that does little, if anything, to benefit or protect the reliable operation of the BES.

Criteria B
- Criterion B1(Administrative)
- Criterion B2 (Data Collection/Data Retention)

Criteria C
1. PRC-010-0 R2 has not been part of a FFT filing.

2. PRC-010-0 R2 is subject to Standards Development Project 2008-02 Undervoltage Load Shedding, which is not currently active and is only estimated to be completed until the second quarter of 2014. Since the purpose of Project 2008-02 does not necessarily include a review of R2 and its 2014 completion date is well into the future, it is appropriate to include PRC-010-0 R2 in the P81 Project.

3. This requirement has a Lower VRF.

4. This requirement is not part of the AML.

5. The retirement of PRC-010-0 R2 does not pose any negative impact to NERC's published and posted reliability principles, particularly since submission of a program assessment or documentation of its analysis of UVLS program performance to a Regional Entity does not seem to implicate any of the principles.

6. For similar reasons, there is no negative impact on a defense in depth strategy because no other requirement depends on it to help cover a reliability gap or risk to reliability.

7. The retirement of PRC-010-0 R2 promotes a results-based approach because it is a data collection requirement, and, therefore, does not provide the foundation for performing a reliability task.

Accordingly, for the above reasons, it is appropriate to retire PRC-010-0 R2.

PRC-022-1 R2 – Under-Voltage Load Shedding Program Performance

> **R2.** Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90 calendar days of a request.

Background/Commission Directives
PRC-022-1 was submitted for Commission approval on April 4, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[76] In Order No. 693 at paragraph 1565 the Commission approved PRC-022-1 without a discussion of R2. There are no outstanding Commission directives with respect to R2.

Technical Justification
Outside the context of a Reliability Standard, under Section 400 of the NERC Rules of Procedure, NERC and the Regional Entities have the authority to require an entity to submit documentation of its analysis of UVLS program performance for purposes of monitoring compliance. Thus, the retirement of PRC-022-1 R2 does not affect the ability for NERC and the Regional Entities to require Reliability Coordinators to produce documentation to monitor compliance with PRC-022-1 R1 and its sub-requirements. Furthermore, PRC-022-1 R1 already requires that the entity document UVLS performance:

> Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall analyze and document all UVLS operations and Misoperations.

Accordingly, retiring PRC-022-1 R2 presents no gap to reliability or to the information NERC and the Regional Entities need to monitor compliance. In this context, a review of R2 indicates that it is a needlessly burdensome administrative and data collection requirement that that does little, if anything, to benefit or protect the reliable operation of

[76] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

the BES. (Criteria A, B1 and B2). Also, similar to the retention of records requirements in CIP-007-3, -4 R7.3, FAC-002-1 R2 and PRC-010-0 R2, the ERO compliance program efficiency will increase since it will no longer need to track a static requirement of whether a UVLS program assessment was submitted within 30 days of a request by NERC or the Regional Entity, and instead, compliance monitoring may focus on the more substantive requirements of PRC-022-1.

Criterion A
R2 is an administrative and data collection requirement that does little, if anything, to benefit or protect the reliable operation of the BES.

Criteria B
- Criterion B1(Administrative)
- Criterion B2 (Data Collection/Data Retention)

Criteria C
1. PRC-022-1 R2 has not been part of a FFT filing.

2. PRC-022-1 R2 is subject to Standards Development Project 2008-02 Undervoltage Load Shedding, which is not currently active and is only estimated to be completed until the second quarter of 2014. Since the purpose of Project 2008-02 does not necessarily include a review of R2 and its 2014 completion date is well into the future, it is appropriate to include PRC-022-1 R2 in the P81 Project.

3. PRC-022-1 R2 has a Lower VRF.

4. This requirement is not part of the AML.

5. The retirement of PRC-022-1 R2 does not pose any negative impact to NERC's published and posted reliability principles, particularly since submission of a program assessment or documentation of its analysis of UVLS program performance to a Regional Entity does not seem to implicate any of the principles.

6. For similar reasons, there is no negative impact defense in depth because no other requirement depends on it to help cover a reliability gap or risk to reliability.

7. The retirement of PRC-022-1 R2 promotes a results-based approach because it is a data collection requirement, and, therefore, does not provide the foundation for performing a reliability task.

Accordingly, for the above reasons, it is appropriate to retire PRC-022-1 R2.

****VAR-001-2 R5 – Voltage and Reactive Control**

R5. Each Purchasing-Selling Entity and Load Serving Entity shall arrange for (self-provide or purchase) reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load– to satisfy its reactive requirements identified by its Transmission Service Provider.

Background/Commission Directives

VAR-001-1 was submitted for Commission approval on April 4, 2006, in Docket No. RM06-16-000. When approving VAR-001-1, in Order No. 693 at paragraph 1858,[77] the Commission recognized:

> . . . that all transmission customers of public utilities are required to purchase Ancillary Service No. 2 under the OATT or self-supply, but the OATT does not require them to provide information to transmission operators needed to accurately study reactive power needs. The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities.

On September 9, 2010, NERC submitted VAR-001-2, which included revisions to Requirement R5 to satisfy Commission directives in Order No. 693, including the directive in paragraph 1858. This directive was addressed by adding "Load Serving Entities" to the standard as applicable entities and making them subject to the same requirements as Purchasing Selling Entities. These modifications to VAR-001-2 were accepted by the Commission on January 10, 2011.[78]

Technical Justification

VAR-001-2 R5 does little, if anything, to benefit or protect the reliable operation of the BES because it is redundant with FERC's *pro forma* open access transmission tariff ("OATT"). (Criteria A and B7). To elaborate, VAR-001-2 R5 provides for the PSE and LSE (transmission customers) to arrange for or self provide reactive resources the same as required under Schedule 2 of the OATT. Specifically, as a general matter Schedule 2 of the OATT states:

> **Schedule 2 Reactive Supply and Voltage Control from Generation or Other**
>
> In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator) are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from

[77] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[78] *North American Electric Reliability Corp.*, 134 FERC ¶ 61,015 (2011).

> Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.
>
> Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. A Transmission Customer may satisfy all or part of its obligation through self provision or purchases provided that the self-provided or purchased reactive power reduces the Transmission Provider's reactive power requirements and is from generating facilities under the control of the Transmission Provider or Control Area operator. The Transmission Customer's Service Agreement shall specify any such reactive supply arrangements. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator. The Transmission Provider's rates for Reactive Supply and Voltage Control from Generation Sources Services shall be set out in Appendix A to this Schedule.

Given the importance of the procurement or self providing of reactive power, even in a market setting a form of Schedule 2 is found in the tariffs of MISO and PJM, for example. While NERC complied with the Commission's directive to add LSEs to VAR-001-2 R5, a review of this requirement in light of Schedule 2 indicates that the reliability objective of ensuring that PSEs as well as LSEs either acquire or self provide reactive power resources associated with its transmission service requests is accomplished via Schedule 2, and, therefore, there is no need to reiterate it in VAR-001-2 R5. The repetitive nature of VAR-001-2 R5 is also apparent in the context of how a PSE or LSE generally demonstrates compliance – via screenshots from Open Access Same-Time Information System ("OASIS") reservations that show the mandatory acquiring or self providing of reactive power resources per Schedule 2.

The reliability objective of VAR-001-2 is also accomplished in VAR-001-2 R2 (that is not proposed for retirement) which reads:

> Each Transmission Operator shall acquire sufficient reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, [sic] and controllable load – within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

The Transmission Operator's adherence to R2 is a double check for the obligations under Schedule 2 to ensure there are sufficient reactive power resources to protect the voltage levels under normal and Contingency conditions.

In addition, in the Electric Reliability Council of Texas (ERCOT) region, where there is no FERC approved OATT, reactive power is handled via Section 3.15 of the ERCOT Nodal Protocols that describes how ERCOT establishes a Voltage Profile for the grid, and then in detail explains the responsibilities of the Generators, Distribution Providers and Texas Transmission Service Providers (not to be confused with a NERC TSP), to meet the Voltage Profile and ensure that those entities have sufficient reactive support to do so. There is further Operating Guide detail on the responsibilities for entities to deploy reactive resources approximately, within performance criteria in the Operating Guide Section 3. Thus, as in non-ERCOT regions, ERCOT has protocols that are duplicative of VAR-001-2 R5.

Given the redundant nature of VAR-001-2 R5 it would also assist the ERO compliance program to retire it, so that time and resources can be reallocated to focus on adherence to other Reliability Standard requirements.

Criterion A
VAR-001-2 R5 does little, if anything, to benefit or protect the reliable operation of the BES because it is redundant with FERC's *pro forma* OATT.

Criteria B

- Criterion B7 (Redundant)

Criteria C

1. VAR-001-2 R5 has not been part of a FFT filing.

2. VAR-001-2 R5 is subject to Standards Development Project 2008-01 Voltage and Reactive Planning Control. Given that Project 2008-01 is not currently active and is only estimated to be completed until the second quarter of 2014 and the purpose of this project does not necessarily include a review of R5, it is appropriate to include VAR-001-2 R5 in the P81 Project. Also, retiring this requirement via P81 Project may facilitate the efficiency of Project 2008-01.

3. This requirement has a High VRF. However, the reliability objective of VAR-001-2 R5 will be accomplished via Schedule 2 of the OATT, ERCOT protocols

and R2 of VAR-001-2. Thus, the High VRF is not dispositive, and VAR-001-2 R5 remains appropriate for retirement.

4. VAR-001-2 R5 is in the third tier of the AML.

5. Because VAR-001-2 R5 is redundant with the *pro forma* OATT and ERCOT protocols, (as well as the reliability objective of VAR-001-2 R5 is accomplished via Schedule 2 of the OATT, ERCOT protocols and R2 of VAR-001-2), the retirement of VAR-001-2 R5 does not pose any negative impact to the following NERC published and posted reliability principles:

   Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

   Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

6. Retirement does not negatively impact defense in depth because no other requirement depends on it to help cover a reliability gap or risk to reliability.

7. The retirement of VAR-001-2 R5 is neutral regarding whether it promotes a results-based approach because the requirement is results-based, but already covered in the *pro forma* OATT, Schedule 2 and ERCOT protocols.

Accordingly, for the above reasons, it is appropriate to retire VAR-001-2 R5.

V. The Initial Phase Reliability Standards Provided for Informational Purposes

The following requirements are already scheduled to be retired or subsumed via another Standards Development Project that has been approved by stakeholders and the NERC Board of Trustees (or due to be before the NERC Board of Trustees in November), and, thus, are presented here for informational purposes only. For regulatory efficiency, these requirements will not be presented for comment and vote, and, therefore, will not be presented to the NERC Board of Trustees for approval or filed with the Commission or Canadian governmental authorities as part of the P81 Project.

COM-001-1.1 R6- Telecommunications

Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001-0, "NERCNet Security Policy."

Background
COM-001-1 was submitted for Commission approval on November 15, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[79] COM-001-1.1 was submitted for Commission approval on February 6, 2009 in Docket No. RD09-2-000 as errata and was approved by unpublished letter order on May 13, 2009.[80]

As part of COM-001-2, on September 17, 2012, stakeholders approved the retirement of COM-001-1.1 R6 in Project 2006-06 (Reliability Coordination). This project is due to be presented to the NERC Board of Trustees in November. Thus, COM-001-1 R6 is presented here for informational purposes only.

EOP-009-0 R2 – Documentation of Blackstart Generating Unit Test Results

R2. The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating unit to the Regional Reliability Organizations and upon request to NERC.

Background
EOP-009-0 was submitted for Commission approval on April 4, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[81] In Order No. 749, the Commission approved the retirement of EOP-009-0 as of July 1, 2013, based on the approval of EOP-005-2, which did not carry forward R2 of EOP-009-0. Thus, EOP-009-0 R2 is presented here for informational purposes only.

FAC-008-1 R1.3.5 – Facility Ratings Methodology

R1.3.5. Other assumptions.

Background
FAC-008-1 was submitted for Commission approval on April 4, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[82]

"On May 12, 2010, the NERC Board of Trustees approved the proposed FAC-008-2 Reliability Standard that addressed the first two of the FERC directives in Order No. 693. NERC's proposed FAC-008-2 Reliability Standard was not filed with FERC for approval, but instead was revisited by the standard drafting team so that the third Order

[79] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[80] Letter Order, Electric Reliability Organization Errata Petition Updating Accepted Reliability Coordination and Transmission Operations Reliability Standards, Docket No. RD09-2-000 (May 13, 2009).
[81] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[82] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

No. 693 directive could be addressed in response to FERC's March 18, 2010 Order…"[83]

FAC-008-3 was submitted for Commission approval on June 15, 2011 in Docket No. RD11-10-000 and was approved on November 17, 2011.[84]

FAC-008-3 (which combined FAC-008 and FAC-009) has been approved by the Commission without the "other assumptions" language.[85] Since FAC-008-3 will become effective on January 1, 2013, FAC-008-1 R1.3.5 is presented here for informational purposes only.

PRC-008-0 R1; PRC-008-0 R2 – Underfrequency Load Shedding Equipment Maintenance Programs

R1. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.

R2. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).

Background
PRC-008-0 was submitted for Commission approval on April 4, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[86]

Under Standards Development Project 2007-17 Protection System Maintenance, which recently passed on August 27, 2012, PRC-008-0 is scheduled to be retired, subsumed and replaced with PRC-005-2. PRC-005-2 will likely be presented to the NERC Board of Trustees in November for approval, and, thus, PRC-008-0 is only presented here for informational purposes.

PRC-009-0 R1; PRC-009-0 R1.1; PRC-009-0 R1.2; PRC-009-0 R1.3; PRC-009-0 R1.4; PRC-009-0 R2 – UFLS Performance Following an Underfrequency Event

[83] Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard FAC-008-3 — Facility Ratings, Docket No. RD11-10-000, (June 15, 2011).
[84] *Order Approving Reliability Standard*, 137 FERC ¶ 61,123 (2011).
[85] *Id.*

[86] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

R1. The Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:

R1.1. A description of the event including initiating conditions.

R1.2. A review of the UFLS set points and tripping times.

R1.3. A simulation of the event.

R1.4. A summary of the findings.

R2. The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.

Background

PRC-009-0 was submitted for Commission approval on April 4, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[87] In Order No. 763 at paragraph 103[88] the Commission accepted the retirement of PRC-009-0 as appropriately replaced with PRC-006-1. Consistent with Order No. 763, PRC-009-0 will become inactive on September 30, 2013 and will be replaced by PRC-006-1. Thus, PRC-009-0 is presented here for informational purposes only.

TOP-001-1a R3 – Reliability Responsibilities and Authorities

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority, or

[87] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[88] *Automatic Underfrequency Load Shedding and Load Shedding Plans Re-liability Standards*, 139 FERC ¶ 61,098 (2012).

> Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

Background

TOP-001-1 was submitted for Commission approval on November 15, 2006 in Docket No. RM06-16-000 and was approved by the Commission on March 16, 2007 in Order No. 693.[89] TOP-001-1a was submitted for approval on July 16, 2010 in Docket No. RM10-29-000 and was approved on September 15, 2011 in Order No. 753.[90]

IRO-001-1a R8 reads:

> Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.

Although there is redundancy between TOP-001-1a R3 and IRO-001-1a R8 as related to Reliability Coordinators, this redundancy was addressed in Standards Development Project 2007-03 (Real-time Operations). Specifically, Project 2007-03 eliminated the redundancy in the current version of TOP-001-2 R1 that replaces TOP-001-1a R3 and reads:

> Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements.

TOP-001-2 has been approved by the NERC Board of Trustees and will be filed with the Commission for approval; therefore, TOP-001-1a R3 is presented for informational purposes only.

TOP-005-2a R1 – Operational Reliability Information

[89] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007). ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[90] *Electric Reliability Organization Interpretation of Transmission Operations Reliability Standard*, 136 FERC ¶ 61,176, (September 15, 2011) (Order No. 753).

R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."

Background

Without directly addressing R1 of TOP-005-1 or TOP-005-2a the Commission approved both versions of TOP-005. [91] A review of the Standards Development Project 2007-03 Real-time Transmission Operations indicates it proposes R1 of TOP-005-1 to be retired. The reasoning provided by the SDT was the following:

> Confidentiality is not a reliability issue, but a market or business issue. Since this is not a reliability issue, it does not belong in the Reliability Standards and can be deleted.[92]

As stated above, in the context of Project 2007-03, TOP-001-1a was approved by the NERC Board of Trustees and will be filed with the Commission for approval; therefore, TOP-005-2a R1 is presented for informational purposes only.

[91] Order No. 693 at paragraphs 1648 through 1652 (approval of TOP-005-1); *Mandatory Reliability Standards for Interconnection Reliability Operating Limits,* 134 F.E.R.C. ¶ 61,213 (2011) (approval of TOP-005-2a).

[92] Mapping Document Project 2007-03 Real-time Operations at page 31 (April 27 2012).

October 23, 2012

Appendix A

			Criteria B							Criteria C						
Standard	**Req.**	**Criterion A**	**B1**	**B2**	**B3**	**B4**	**B5**	**B6**	**B7**	**C1**	**C2**	**C3**	**C4**	**C5**	**C6**	**C7**
		Reliability Impact	Administrative	Data	Documentation	Reporting	Updates	Commercial	Redundant	FFT	Ongoing Project	VRF	AML Tier	Reliability Principles Implicated?	In-depth Protection Implicated?	Results-based promoted?
BAL-005-0.2b	**R2**	√							√			H		No	No	Yes
CIP-001-2a	**R4**	√	√	√	√					√	√	M	2	No	No	Yes
CIP-003-3, -4	**R1.2**	√	√							√	√	L	2	No	No	Yes
CIP-003-3, -4	**R3, R3.1 R3.2 R3.3**	√	√		√					√	√	L	3	No	No	Yes
CIP-003-3, -4	**R4.2**	√	√		√				√	√	√	L	3	No	No	Yes
CIP-005-3a, -4a	**R2.6**	√	√		√					√	√	L	1	No	No	Yes
CIP-007-3, -4	**R7.3**	√	√	√							√	L	1	No	No	Yes
EOP-004-1	**R1**	√	√		√						√	L	3	No	No	Yes
EOP-005-2	**R3.1**	√	√				√		√			N/A	2	No	No	Yes
FAC-002-1	**R2**	√	√	√								L	3	No	No	Yes
FAC-008-1	**R2, R3**	√	√			√		√				L	3	No	No	Yes
FAC-008-3	**R4 R5**	√	√			√		√				L	3	No	No	Yes

			Criteria B							Criteria C						
Standard	**Req.**	**Criterion A**	**B1**	**B2**	**B3**	**B4**	**B5**	**B6**	**B7**	**C1**	**C2**	**C3**	**C4**	**C5**	**C6**	**C7**
		Reliability Impact	Administrative	Data	Documentation	Reporting	Updates	Commercial	Redundant	FFT	Ongoing Project	VRF	AML Tier	Reliability Principles Implicated?	In-depth Protection Implicated?	Results-based promoted?
FAC-010-2.1	**R5****	√	√			√		√				L		No	No	Yes
FAC-011-2	**R5****	√	√			√		√				L		No	No	Yes
FAC-013-2	**R3**	√	√			√		√				L		No	No	Yes
INT-007-1	**R1.2**	√	√									L		No	No	Yes
IRO-016-1	**R2**	√	√	√								L		No	No	Yes
NUC-001-2	**R9.1** **R9.1.1** **R9.1.2** **R9.1.3** **R9.1.4**	√	√									N/A	3	No	No	Yes
PRC-010-0	**R2**	√	√	√								L		No	No	Yes
PRC-022-1	**R2**	√	√	√								L		No	No	Yes
VAR-001-2	**R5****	√							√			H	3	No	No	Yes

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Retirement of Reliability Standard Requirements		
Date Submitted:	September 12~~June 29~~, 2012		
SAR Requester Information			
Name:	Brian J. Murphy on behalf of the following:		
Organization:	P81 Interim Standards Drafting Team, as originally supported by Edison Electric Institute, American Public Power Association, National Rural Electric Cooperative Association, Large Public Power Council, Electricity Consumers Resource Council, The Electric Power Supply Association, Transmission Access Policy Study Group, the North American Electric Reliability Corporation, and the Regional Entity Management Group		
Telephone:	305-442-5132		
SAR Type (Check as many as applicable)			
☐ New Standard		☒ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
On March 15, 2012, the Federal Energy Regulatory Commission (FERC) issued an order on NERC's Find, Fix and Track process that stated: "The Commission notes that NERC's FFT initiative is predicated on the view that many violations of requirements currently included in Reliability Standards pose lesser

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risk to the Bulk-Power System. If so, some current requirements likely provide little protection for Bulk-Power System reliability or may be redundant. The Commission is interested in obtaining views on whether such requirements could be removed from the Reliability Standards with little effect on reliability and an increase in efficiency of the ERO compliance program. If NERC believes that specific Reliability Standards or specific requirements within certain Standards should be revised or removed, we invite NERC to make specific proposals to the Commission identifying the Standards or requirements and setting forth in detail the technical basis for its belief. In addition, or in the alternative, we invite NERC, the Regional Entities and other interested entities to propose appropriate mechanisms to identify and remove from the Commission-approved Reliability Standards unnecessary or redundant requirements. We will not impose a deadline on when these comments should be submitted, but ask that to the extent such comments are submitted NERC, the Regional Entities, and interested entities coordinate to submit their respective comments concurrently."

North American Electric Reliability Corporation, 138 FERC ¶ 61,193 at p 81 (March 15, 2012) ("P81").

Consistent with P81, the problem this SAR is resolving is to identify Reliability Standards requirements that either: (a) provide little protection to the BPS;[1] (b) are unnecessary or (c) are redundant; and, thereafter, to have NERC file the identified Reliability Standard requirements with FERC to have them removed from the FERC-approved list of Reliability Standards.

In addition to addressing P81, this SAR is also consistent with Recommendation #4 set forth in *NERC's Recommendations to Improve The Standards Development Process* at page 12 (April 2012), which states:

> **Recommendation 4: Standards Product Issues** — The NERC board is encouraged to require that the standards development process address: . . . The retirement of standards no longer needed to meet an adequate level of reliability.

[1] Given NERC's Reliability Standards are based on the definition of a Bulk Electric System (BES), the remainder of this SAR will use the term BES rather than Bulk Power System or BPS.

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SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
The SAR addresses the problem identified above by: (1) Setting forth the initial phase-specific criteria (below) to evaluate whether a Reliability Standard requirement provides little protection to BES reliability or is unnecessary or redundant. (2) Establishing a multi-phased process for addressing these Reliability Standard requirements. During the initial phase~~Initial Phase~~, the standard drafting team~~Standards Drafting Team~~ will identify those Reliability Standard requirements that ~~easily~~ satisfy the criteria, set forth below, without the need for extensive technical justification or a modification to the requirement, and ~~either~~ recommend~~: (a)~~ the retirement of the requirement.[2] During subsequent[3] ~~or (b) a modification to the requirement,~~[4] ~~while future~~ phases, the standard drafting team may build upon the initial phase criteria, as applicable, to that phase that will identify the remaining appropriate Reliability Standard requirements that ~~satisfy the criteria, but~~ could not be included in the initial phase~~Initial Phase~~ due to the need for additional analysis or a modification of language. This multi-phased approach is also proposed to address FERC's interest in increasing the efficiency of the ERO compliance program, so that the first set of identified Reliability Standard requirements may be filed with FERC on an expedited basis, and, therefore, start increasing ERO efficiencies as soon as practical. (3) At this time,~~To facilitate~~ the standard drafting team has identified~~Initial Phase of the Standard Drafting Team's process,~~ a list of Reliability Standard requirements to be included in the initial phase that ~~appear to easily~~ satisfy the criteria ~~are~~ set forth below.

[2] The Standards Drafting Team will work with NERC staff to determine the manner to eliminate the identified Reliability Standard requirements.

[3] ~~The Standards Drafting Team will work with NERC staff to determine the manner to eliminate the identified Reliability Standards requirements.~~

[4] ~~Given the expedited nature of the Initial Phase, it is unlikely there will be a large number of modifications considered, and the Standards Drafting Team may decide to defer all requested modifications to subsequent phases.~~

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(4) During each phase, as a list of Reliability Standard requirements is identified, the standard drafting team ~~and passes through the Standards Development Process, the Standards Drafting Team~~[5] will also assist NERC staff to file these requirements with FERC so the requirements are removed from the FERC-approved list, including providing additional technical justification, as needed.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objectives of this SAR for all phases of this project are to retire or modify FERC-approved Reliability Standard requirements that provide little protection to the reliable operations of the BES, are redundant or unnecessary, or to retire or modify a FERC-approved Reliability Standard requirement to increase the efficiency of the ERO's compliance programs.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The scope of this SAR is all FERC-approved Reliability Standards.[6]
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The standard drafting team~~Standard Drafting Team~~ shall implement a phased process. The Initial Phase shall identify all FERC- approved Reliability Standard requirements that ~~easily satisfy the criteria set forth below, while future phases shall identify FERC-approved Reliability Standard requirements that satisfy the criteria set forth below, but could not be included in the Initial Phase due to the need for additional analysis or an editing of language. During each phase the Standards Drafting Team shall~~

~~[5] While this SAR applies to all phases of the P81 project, it is understood that the composition of the Standard Drafting Team may need to change or be supplemented in subsequent phases depending on the technical expertise required.~~

[6] The scope of this SAR with regard to those requirements that are proposed for retirement includes any currently pending versions of the listed Reliability Standards and any additional version of these Reliability Standards that may be submitted. In other words, the intent is to carry forward these retirements based on substance which is not dependent on the exact numbering or placement within a Reliability Standard.

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~~identify Reliability Standard requirements that~~ satisfy **both**: (i) Criteria A ~~(~~) ~~the~~ overarching criteria) and (ii~~B~~) at least one of the Criteria B listed below (identifying~~technical~~ criteria). ~~.~~ In addition, for all phases, the standard drafting team~~Standards Drafting Team~~ shall also consider the data and reference points set forth below in Criterion C when deciding whether a Reliability Standard requirement should be retired or modified.

A. Overarching Criterion:

The~~In the event no responsible entity performed the FERC-approved~~ Reliability Standard requirement requires responsible entities to conduct an activity or task that does~~, there would be~~ little, if anything, ~~or no impact~~ to benefit~~the protection~~ or protect the reliable operation of the BES.

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Section 215(a)(4) of the Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

B. Identifying~~Technical~~ Criteria:

1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

2. Data Collection/Data Retention

~~The Reliability Standard requirement requires responsible entities to collect or retain data and does not contribute to: (a) the reliable operation of the BES or (b) an effective compliance enforcement processes.~~ These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes ~~or addressed in the data retention sections of Reliability Standards~~.

3. ~~Purely~~ Documentation

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The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

4. ~~Purely~~ Reporting

The Reliability Standard requirement obligates responsible entities to report ~~out~~ to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible ~~discernable~~ impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there ~~it~~ would be ~~have~~ little reliability impact ~~on the reliable operation of the BES~~.

5. Periodic Updates

The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

6. Commercial or Business Practice

The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues. ~~*e.g.,* better served as a NAESB standard or as part of NAESB Electric Industry Registry (EIR).~~

7. Redundant

The Reliability Standard requirement is redundant with (i) ~~either~~ another FERC-approved Reliability Standard requirement; (ii) the ERO compliance and monitoring program; or (iii) a ~~or~~ governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), ~~,~~ etc.).

~~**8. Hinders the protection or reliable operation of the BES**~~

~~The Reliability Standard requirement requires responsible entities to conduct an activity or task that hinders, distracts or is counterproductive to the protection or reliable operation of the BES.~~

~~**9. Little, if any, value as a reliability requirement**~~

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~~The tasks or activities in the Reliability Standard requirement do little, if anything, to promote the protection the BES.~~

C. Additional data and reference points

In those instances where~~when~~ there is a~~the~~ need for additional information to assist in the determination of whether a Reliability Standard requirement satisfies both Criteria A and B, the standard drafting team~~Standards Drafting Team~~ shall consider the following data and reference points to make a more informed decision:

1. Was the Reliability Standard requirement part of a Find, Fix and Track filing?

2. Is the Reliability Standard requirement being reviewed in an on-going Standards Development Project?

3. What is the Violation Risk Factor of the Reliability Standard requirement?

4. In which tier of the 2013 Actively Monitored List~~Standards~~ does the Reliability Standard requirement fall?

5. Is there a possible~~Any~~ negative impact on NERC's published and posted reliability principles?

6. Is there any~~Any~~ negative impact on the defense-in-depth protection of the BES?

7. Does the retirement ~~or modification~~ promote results- or performance-based Reliability Standards?

To facilitate the standard drafting team's~~Standard Drafting Team's~~ consideration of the above questions, NERC staff will provide the team with relevant known data and statistics.

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List of Initial Phase~~To facilitate the Standard Drafting Team's Initial Phase, below is a list of Reliability Standard requirements that appear to satisfy both Criteria A and B, with consideration of Criterion C. To assist the Team's review of these requirements, Criterion B coding is provided, along with a brief statement explaining why the requirement provides little protection to the BES, is unnecessary or is redundant.~~

~~List of Phase One~~ Reliability Standard requirements that satisfy both Criteria A and B, with consideration of Criterion C

To be retired:[7]

BAL-005-0.2b~~1b~~ R2

Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

Criterion B 7.

Statement:[8] BAL-005-0.2b~~1b~~ is redundant with the Control Performance Standard defined in BAL-001-0.1a R1 and R2. This is also redundant in that it is measured by whether or not BAL-001-0.1a R1 and R2

[7] The following requirements that were originally presented in the draft SAR, and now in this final SAR are denoted with a "*" are so denoted because research shows that they are already scheduled to be retired via another Standards Development Project that has been approved by stakeholders and the NERC Board of Trustees (or due to be before the Board in November – *i.e.*, PRC-005-2), and, thus, are presented here for informational purposes only: COM-001-1.1 R6, EOP-009-0 R2; FAC-008-1 R1.3.5; PRC-008-0 R1; PRC-008-0 R2; PRC-009-0 R1; PRC-009-0 R1.1; PRC-009-0 R1.2; PRC-009-0 R1.3; PRC-009-0 R1.4; PRC-009-0 R2; TOP-001-1a R3 and TOP-005-2a R1. These requirements are generally scheduled to be retired within the next year, and, therefore, to subject them to additional stakeholder vote, comment and Board of Trustees approval does not seem warranted or efficient. Consequently, these requirements will not be presented to stakeholders for comment and vote.

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are met.

Conclusion: This is redundant with the Control Performance Standard defined in BAL-001-0.1a R1 and R2. This is also redundant in that it is measured by whether or not BAL-001-0.1a R1 and R2 are met. This may be double jeopardy in that failure to achieve compliance with BAL-001-0.1a R1 and R2 could imply failure of this standard as well. This is misleading in requiring entities to maintain Regulating Reserve, but providing no way to measurably comply, apart from achieving compliance with BAL-001-0.1a R1 and R2.

CIP-001-2a -R4.

Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.

Criterion B 1, 2~~, 3, 8~~ and 3~~9~~.

Statement: CIP-001-2a is administrative, documentation and data collection in nature, because the establishment of communication contacts, in and of itself, with the FBI and RCMP has little or no impact on protection or the reliable operation of the BES. Instead, compliance with R1 through ~~-~~R3 of CIP-001-2a provides the actions that responsible entities take to protect the BES in the event of sabotage. Specifically, R1 through R3 require that the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity ~~to~~ have procedures for the recognition of sabotage, reporting of sabotage and communication of sabotage events to appropriate parties in the Interconnection, which may include local law enforcement, the FBI, etc. Thus, ~~in~~ CIP-001-2a~~,~~ R1 through R3 serve a reliability function, while R4 is a static, administrative requirement that has no clear results-based nexus to protecting the BES.~~Bulk Electric System (BES).~~

[8] The "Statement" and "Conclusion" sections are brief statements that provide context. The technical justification for each Reliability Standards requirement is contained in a separate Technical White Paper that will also be posted for comment.

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Conclusion: Since this requirement provides little protection to the BES and is administrative in nature, Requirement 4 should be removed from Reliability Standard CIP-001-2a. **CIP-003-3, -4 R1.2** The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets. Criterion B 1. **Statement:** Whether there is a robust CIP compliance plan on which employees are trained -may impact reliability, not whether the cyber security policy is readily available. Employees that are responsible for executing the cyber security policy are required to undergo a variety of training and, follow multiple processes and procedures that are already required by the CIP requirements. Simply requiring that the policy be readily available is an administrative task that provides little, if any, benefit to reliability of the BES. **Conclusion:** Since this requirement provides little protection to the BES and is purely administrative in nature, Requirement 1.2 should be removed from Reliability Standards CIP-003-3 and CIP-003-4. **CIP-003-3, -4 R3, R3.1, R3.2, R3.3** R3 Exceptions – Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s). R3.1 Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s). R3.2 Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures. R3.3 Authorized exceptions to the cyber security policy must be reviewed and approved

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annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented. Criterion B 1~~, 3~~ and 3~~8~~. **Statement:** Over time, these exception requirements have proven to not be useful and have been subject to misinterpretation, including responsible entities believing they can exempt themselves from compliance with the CIP requirements. **Conclusion:** For regulatory efficiency, since these requirements provide little protection to the BES and are open to misinterpretation, in addition to being entirely documentation, Requirement 3 and its sub-requirements~~subrequirements~~ should be removed from Reliability Standards~~Standard~~ CIP-003-3 and CIP-003-4. **CIP-003-3, -4 R4.2.** The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information. Criterion B 1, 3 and 7. **Statement:** CIP-003-3, -4 R4 already requires the classification of information associated with Critical Cyber Assets, which makes R4.2 redundant. The only difference in R4.2 is the term, "based on the sensitivity" has been added. The addition of this term can be viewed as overly managing the responsible entities' process of classification or simply not adding sufficient value to reliability to require a new requirement over and above R4. **Conclusion:** Since this requirement is~~these requirements are~~ redundant and provides~~provide~~ little protection to the BES, Requirement 4.2 should be removed from both Reliability Standards CIP-003-3 and CIP-003-4.

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CIP-005-3a, -4a R2.6. Appropriate Use Banner -- Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner. ~~devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.~~ Criterion B 1~~, 3, 8~~ and 3~~9~~. **Statement:** Over time, the banner requirement (or no trespass sign) has not been shown to be useful or consistent with a results-based approach to implementing a cyber security program. Additionally, it is administrative in nature. **Conclusion:** Since this requirement provides little protection to the BES and is purely administrative in nature, Requirement R2 should be removed from Reliability Standards CIP-005-3a and CIP-005-4. **CIP-007-3, -4 R7.3** The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures. Criterion B 1 and 2. **Statement:** CIP-007-3, -4 R7.3 is evidence collection and possible for inclusion in an RSAW. **Conclusion:** Since this requirement provides little protection to the BES and is data collection in nature, it should be removed from CIP-007-3, -4. ***COM-001-1.1 R6.**

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Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001-0, "NERCNet Security Policy." Criterion B 6 and 7. **Statement:** ~~Whether the entity has a robust up-to-date CIP compliance plan may impact reliability, but not whether it employs a specific business practice such as the NERCNet. NOTE:~~ This requirement has been approved by stakeholders~~is proposed~~ for removal per Project 2006-06 (Reliability Coordination) and will ~~with the rationale: "The RC SDT is recommending that R6~~ be presented to the NERC Board of Trustees for approval~~retired. This is an ERO procedural issue and should not be~~ in November. Thus,~~a reliability standard. It should be included in the ERO Rules of Procedure."~~ ~~**Conclusion:** Since this requirement provides little protection to the BES and is more appropriate as a Commercial and Business Practice, Requirement 6 should be removed from Reliability Standard~~ COM-001-1.1 R6 is presented here for informational purposes only. **EOP-004-1 R1.** Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports. Criterion B 1~~, 3~~ and 3~~4~~. **Statement:** Whether or not there is a Regional Entity procedure to report disturbances has no impact on reliability. In other words, while a procedure for the collection of reports on disturbances may be useful information for purposes of Regional Entities to stay informed during events, is not an activity that protects the reliability of BES. The collection of such information should be established outside mandatory Reliability Standards. **Conclusion:** Since this requirement provides little protection to the BES and is purely documentation, Requirement 1 should be removed from Reliability Standard EOP-004-1.

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EOP-005-2 R3.1.

If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary.

Criterion B 1, 5~~,~~ ~~7~~ and 7~~9~~.

Statement: EOP-005-2 R3 reads: "Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually agreed predetermined schedule." This requirement requires the Transmission Operator to submit its restoration plan to the Reliability Coordinator whether or not there have been changes. Therefore, R3.1 only adds a duplicative administrative burden for the entity to also confirm that there were no changes based upon another possible pre-determined schedule. Whether or not there was a change from year to year in the restoration plan will be documented in the revision history of the restoration plan, and thus the Reliability Coordinator will be able to ascertain whether or not there were changes based on R3. Thus, EOP-005-2 R3.1 provides little, if any, value to promoting the protection of the BES.

Conclusion: For regulatory efficiency, and since this requirement appears redundant to R3, Requirement 3.1 should be removed from Reliability Standard EOP-005-2.

***EOP-009-0 R2.**

The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating unit to the Regional Reliability Organizations and upon request to NERC.

Criterion B 4.

Statement: In Order No. 749, the Commission approved the retirement of EOP-009-0 R2 as of July 1, 2013, and, thus, it is presented here for informational purposes only.

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~~**Statement:** The requirement to report blackstart test results to the Regional Entity and NERC has no impact on reliability. If the Regional Entity desires to review or track this information, a better vehicle to obtain it is via a Compliance Audit or Spot-Check, or some other compliance monitoring procedure.~~

~~**Conclusion:** For regulatory efficiency and since this requirement is purely a reporting activity, Requirement 2 should be removed from Reliability Standard EOP-009-0.~~

FAC-002-1 R2.

The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

Criterion B 1~~2, 3~~ and 2~~4~~.

Statement: Requiring the retention of studies for three years has no impact on protecting or the reliable operation of the BES, and is merely a data retention requirement that is better suited to be considered during an audit or in the context of compliance monitoring.

Conclusion: Since this requirement provides little protection to the BES and is purely data collection/retention, Requirement 2 should be removed from Reliability Standard FAC-002-1.

***FAC-008-1 R1.3.5.**

Other assumptions.

Criterion B 1~~8~~.

Statement: The term “other assumptions" has already been removed via FAC-008-3, which will be

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effective on January 1, 2013, and, thus, it is presented here for informational purposes only~~in the context of facility ratings is very close to meaningless from a technical standpoint, generic and, therefore, yields no protection of the BES~~.

~~**Conclusion:** Since this requirement provides little or no protection to the BES and is unnecessary, Requirement 1.3.5 should be removed from Reliability Standard FAC-008-1.~~

FAC-008-1 R2; FAC-008-1 R3; FAC-008-3 R4; FAC-008-3 R5

FAC-008-1 R2 The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.

FAC-008-1 R3 If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

FAC-008-3 R4 Each Transmission Owner shall make its Facility Ratings methodology and each Generator Owner shall each make its documentation for determining its Facility Ratings and its Facility Ratings methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners and Planning Coordinators that have responsibility for the area in which the associated Facilities are located, within 21 calendar days of receipt of a request.

FAC-008-3 R5 If a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Coordinator provides documented comments on its technical review of a Transmission Owner's Facility Ratings methodology or Generator Owner's documentation for determining its Facility Ratings and its Facility Rating methodology, the Transmission Owner or Generator Owner shall provide a response to that commenting entity within 45 calendar days of receipt of those comments. The response shall

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indicate whether a change will be made to the Facility Ratings methodology and, if no change will be made to that Facility Ratings methodology, the reason why.

Criterion B 1, ~~2,~~ 4 and 6.

Statement: For purposes of reliability, facility ratings are transmitted and used via the FAC (System Operating Limits), MOD and TPL Standards,[9] and posting the rating methodology for comment and responding to comments in and of itself has no reliability benefit. Furthermore, these requirements do not appear appropriate given the possible commercial or market related implications of sharing and debating with a competitor the facility ratings methodology of a facility.

Conclusion: For regulatory efficiency and possible commercial or market implications in sharing the facility ratings, and since these requirements are purely administrative in nature along with reporting activities, Requirements R2 and R3 of Reliability Standard FAC-008-1 and Requirements 4 and 5 of Reliability Standard FAC-008-3 should be removed from the Standards.

FAC-010-2.1 R5; FAC-011-2 R5

FAC-010-2.1 R5 If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

FAC-011-2 R5 If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason

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[9] MOD-001-1a R9, MOD-028-1 R2.3; MOD-029-1a R2.1; MOD-030-02 R3.1, PRC-023-2, Attachment A 2.7; TPL-001-0.1 Footnote a; TPL-002-1b, footnotes a and b; TPL-003-0a, footnote a and TPL-004-0, footnote a. Also, via FAC-011-2 the System Operating Limits methodology of Reliability Coordinator may also use facility ratings as a key element. Also, FAC-008-3 R7 and R8 require the transmission of facility ratings to reliability entities.

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why.

Criterion B 1, 4 and 6.

Statement: A review of FAC-010-2.1 R5 and FAC-011-2 R5 indicate they are administrative requirements for the Planning Authority and Reliability Coordinator to respond to comments on its SOL methodology. Thus, similar to FAC-008-3 R4 and R5, there is no or little protection for BES reliability for a Planning Coordinator or Reliability Coordinator to enter into a give and take with the recipient on its SOL methodology.

Conclusion: Since these requirements are purely administrative, FAC-010-2.1 R5 and FAC-011-2 R5 should be removed from the Standards.

FAC-013-2 R3

If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why.

Criterion B 1, ~~2,~~ 4 and 6.

Statement: Similar to the concerns with FAC-008, the FAC-013-2 requirement to reply to comments on a transfer capability methodology has no reliability benefit, and, moreover, a back and forward on transfer capability could have commercial or market implications.

Conclusion: For regulatory efficiency and possible commercial or market implications in sharing transfer capability methodology, and since these requirements are purely administrative in nature along with reporting activities, Requirement R3 of Reliability Standard FAC-013-2 should be removed from the Standards.

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INT-007-1 R1.2

All reliability entities involved in the Arranged Interchange are currently in the NERC registry.

Criterion B 1.

Statement: INT-007-1, R1.2 is administrative in nature, and adds little to reliability.

Conclusion: Since INT-007-1 R1.2 provides little protection to the BES, it should be removed.

IRO-016-1 R2

The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.

Criterion B 1 and 2.

Statement:

IRO-016-1 R2 is an evidence requirement and is a candidate. Candidate to go into an RSAW.

Conclusion: Since IRO-016-1 R2 provides little protection to the BES and is data collection in nature, it should be removed.

MOD-004-1 R1; MOD-004-1 R1.1; MOD-004-1 R1.2; MOD-004-1 R1.3; MOD-004-1 R2; MOD-004-1 R3; MOD-004-1 R3.1; MOD-004-1 R3.2; MOD-004-1 R4; MOD-004-1 R4.1; MOD-004-1 R4.2; MOD-004-1 R5; MOD-004-1 R5.1; MOD-004-1 R5.2; MOD-004-1 R6; MOD-004-1 R6.1; MOD-004-1 R6.2; MOD-004-1 R7; MOD-004-1 R8; MOD-004-1 R9; MOD-004-1 R9.1; MOD-004-1 R9.2; MOD-004-1 R10; MOD-004-1 R11; MOD-004-1 R12; MOD-004-1 R12.1; MOD-004-1 R12.2; MOD-004-1 R12.3.

R1 The Transmission Service Provider that maintains CBM shall prepare and keep current a "Capacity

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~~Benefit Margin Implementation Document" (CBMID) that includes, at a minimum, the following information: [Time Horizon: Operations Planning, Long-term Planning]~~ ~~R1.1. The process through which a Load-Serving Entity within a Balancing Authority Area associated with the Transmission Service Provider, or the Resource Planner associated with that Balancing Authority Area, may ensure that its need for Transmission capacity to be set aside as CBM will be reviewed and accommodated by the Transmission Service Provider to the extent Transmission capacity is available.~~ ~~R1.2. The procedure and assumptions for establishing CBM for each Available Transfer Capability (ATC) Path or Flowgate.~~ ~~R1.3. The procedure for a Load-Serving Entity or Balancing Authority to use Transmission capacity set aside as CBM, including the manner in which the Transmission Service Provider will manage situations where the requested use of CBM exceeds the amount of CBM available.~~ ~~R2. The Transmission Service Provider that maintains CBM shall make available its current CBMID to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, Resource Planners, and Planning Coordinators that are within or adjacent to the Transmission Service Provider's area, and to the Load Serving Entities and Balancing Authorities within the Transmission Service Provider's area, and notify those entities of any changes to the CBMID prior to the effective date of the change. [Time Horizon: Operations Planning]~~ ~~R3. Each Load-Serving Entity determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: [Time Horizon: Operations Planning]~~ ~~R3.1. Using one or more of the following to determine the GCIR:~~ ~~Loss of Load Expectation (LOLE) studies~~ ~~Loss of Load Probability (LOLP) studies~~ ~~Deterministic risk-analysis studies~~

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~~Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities~~ ~~R3.2. Identifying expected import path(s) or source region(s).~~ ~~R4. Each Resource Planner determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: [Time Horizon: Operations Planning]~~ ~~R4.1. Using one or more of the following to determine the GCIR:~~ ~~Loss of Load Expectation (LOLE) studies~~ ~~Loss of Load Probability (LOLP) studies~~ ~~Deterministic risk-analysis studies~~ ~~Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities~~ ~~R4.2. Identifying expected import path(s) or source region(s).~~ ~~R5. At least every 13 months, the Transmission Service Provider that maintains CBM shall establish a CBM value for each ATC Path or Flowgate to be used for ATC or Available Flowgate Capability (AFC) calculations during the 13 full calendar months (months 2-14) following the current month (the month in which the Transmission Service Provider is establishing the CBM values). This value shall: [Time Horizon: Operations Planning]~~ ~~R5.1. Reflect consideration of each of the following if available:~~ ~~Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Service Provider's area~~ ~~Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission~~

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~~Service Provider's area~~ ~~Any reserve margin or resource adequacy requirements for loads within the Transmission Service Provider's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities~~ ~~R5.2 Be allocated as follows:~~ ~~For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners~~ ~~For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Service Provider~~ ~~R6 At least every 13 months, the Transmission Planner shall establish a CBM value for each ATC Path or Flowgate to be used in planning during each of the full calendar years two through ten following the current year (the year in which the Transmission Planner is establishing the CBM values). This value shall: [Time Horizon: Long-term Planning]~~ ~~R6.1 Reflect consideration of each of the following if available:~~ ~~Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Planner's area~~ ~~Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Planner's area~~ ~~Any reserve margin or resource adequacy requirements for loads within the Transmission Planner's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities~~ ~~R6.2 Be allocated as follows:~~ ~~For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners~~

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~~For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Planner.~~

~~R7. Less than 31 calendar days after the establishment of CBM, the Transmission Service Provider that maintains CBM shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the Transmission Service Provider's system of the amount of CBM set aside. [Time Horizon: Operations Planning]~~

~~R8. Less than 31 calendar days after the establishment of CBM, the Transmission Planner shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the system being planned by the Transmission Planner of the amount of CBM set aside. [Time Horizon: Operations Planning]~~

~~R9. The Transmission Service Provider that maintains CBM and the Transmission Planner shall each provide (subject to confidentiality and security requirements) copies of the applicable supporting data, including any models, used for determining CBM or allocating CBM over each ATC Path or Flowgate to the following: [Time Horizon: Operations Planning, Long-term Planning]~~

~~R9.1. Each of its associated Transmission Operators within 30 calendar days of their making a request for the data.~~

~~R9.2. To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, Resource Planner, or Planning Coordinator within 30 calendar days of their making a request for the data.~~

~~R10. The Load-Serving Entity or Balancing Authority shall request to import energy over firm Transfer Capability set aside as CBM only when experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher. [Time Horizon: Same-day Operations]~~

~~R11. When reviewing an Arranged Interchange using CBM, all Balancing Authorities and Transmission Service Providers shall waive, within the bounds of reliable operation, any Real-time timing and ramping~~

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~~requirements. [Time Horizon: Same-day Operations]~~

~~R12. The Transmission Service Provider that maintains CBM shall approve, within the bounds of reliable operation, any Arranged Interchange using CBM that is submitted by an "energy deficient entity" under an EEA 2 if: [Time Horizon: Same-day Operations]~~

~~R12.1. The CBM is available~~

~~R12.2. The EEA 2 is declared within the Balancing Authority Area of the "energy deficient entity," and~~

~~R12.3. The Load of the "energy deficient entity" is located within the Transmission Service Provider's area.~~

~~Criterion B 6.~~

~~**Statement:** Capacity Benefit Margin (CBM) is better integrated in marketing functions and is not a reliability function. In the NERC TOP-002 Operations Planning Standard, Requirement R1 specifies that the Transmission Operator shall have an Operating Planning Analysis that represents projected System conditions to assess planned operation for the next day that do not exceed Facility Ratings or Stability Limits for anticipated normal and contingency events. Further, the CBM standard is redundant to the TOP-002 R1 where the marketer would schedule their transmission reserve within the limits established by the Transmission Operator. The Transmission Operator ensures that the established reserve along with other identified schedules are modeled to anticipate next-day conditions and remain within established operating limits.~~

~~In addition, this Standard is not necessary for the support of BES reliability as evidenced by the fact that of the entities that once used CBM, many dropped it when it became effective due to the unnecessary burdens it placed on the entities.~~

~~**Conclusion:** The requirements above relate to commercial and market issues regulated under OATT.~~

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~~Furthermore, they provide little protection to the BES and unnecessary as part of NERC Reliability Standards. Requirements 1 through 12 and associated subrequirements should be removed from Reliability Standard MOD-004-1.~~ **NUC-001-2 R9.1; NUC-001-2 R9.1.1; NUC-001-2 R9.1.2; NUC-001-2 R9.1.3; NUC-001-2 R9.1.4** R9.1 Administrative elements: R9.1.1 Definitions of key terms used in the agreement. R9.1.2 Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs. R9.1.3 A requirement to review the agreement(s) at least every three years. R9.1.4 A dispute resolution mechanism. Criterion B 1~~, 3, 5, 6~~. **Statement:** These requirements of NUC-001-2 do not address reliability, rather they address administrative and commercial terms of an agreement. Given there is no clear nexus between these requirements and reliability, they should be retired. **Conclusion:** Since these requirements are purely administrative in nature, provide for a periodic update and commercial terms of the agreement, they provide little protection to the BES. Requirement 9.1 and associated sub-requirements~~subrequirements~~ should be removed from Reliability Standard NUC-001-2. ***PRC-008-0 R1; *PRC-008-0 R2; *PRC-009-0 R1; *PRC-009-0 R1.1; *PRC-009-0 R1.2; *PRC-009-0 R1.3; *PRC-009-0 R1.4; *PRC-009-0 R2; PRC-010-0 R2; PRC-022-1 R2.**

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PRC-008-0 R1 The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance. PRC-008-0 R2 The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days). PRC-009-0 R1 The Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to: PRC-009-0 R1.1 A description of the event including initiating conditions. PRC-009-0 R1.2 A review of the UFLS set points and tripping times. PRC-009-0 R1.3 A simulation of the event. PRC-009-0 R1.4 A summary of the findings. PRC-009-0 R2 The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.

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PRC-010-0 R2 The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days).

PRC-022-1 R2 Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90 calendar days of a request.

Criterion B 1 and 2~~4, 9~~.

Statement: Under Standards Development Project 2007-17 Protection System Maintenance, which recently passed on August 27, 2012, PRC-008-0 is scheduled to be retired~~Since UVLS~~ and replaced with PRC-005-2. PRC-005-2 will likely be presented to the NERC Board of Trustees in November for approval~~UFLS information is being collected under event analysis~~, and, thus, PRC-008-0 is only presented here for informational purposes. In Order No. 763 at Paragraph 103 the Commission accepted the retirement of PRC-009-0 as appropriately replaced with PRC-006-1. Consistent with Order No. 763, ~~also~~ PRC-009-0 will become inactive on September 30, 2013 and will be replaced by PRC-006-1. Thus, PRC-009-0 is presented here for informational purposes only.

Conversely, PRC-010-0 R2 and PRC-022-1 R2 are not scheduled to be retired and are purely administrative and data collection~~, the above~~ requirements that are better and more appropriately handled via spot checks/compliance audit request for evidence and the applicable RSAW.~~add little to reliability.~~

Conclusion: Since PRC-~~008-0 R1; PRC-008-0 R2; PRC-009-0 R1; PRC-009-0 R1.1; PRC-009-0 R1.2; PRC-009-0 R1.3; PRC-009-0 R1.4; PRC-009-0 R2; PRC-~~010-0 R2 and~~;~~ PRC-022-1 R2 provide~~provides~~ little protection to the BES and better handled via the compliance and monitoring program~~under event analysis and lessons learned papers, it should be removed~~.

***TOP-001-1a R3**

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Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority, or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions. Criterion B 7. **Statement:** Although there is redundancy between TOP-001-1a R3 and ~~is redundant with~~ IRO-001-1a R8 related to Reliability Coordinators, this redundancy was addressed in Standards Development Project~~. NOTE: per project~~ 2007-03 (Real-time Operations). Specifically, Project 2007-03 eliminated the redundancy in the current version of TOP-001-2 R1 that replaces~~), this requirement was removed from~~ TOP-001-1a R3 and ~~and proposed to be replaced by IRO-001-3, R2, R3, R4.~~ ~~**IRO-001-1a R8**~~ reads: Each~~Transmission Operators,~~ Balancing Authority~~Authorities~~, Generator Operator, Distribution Provider, and ~~Operators, Transmission Service Providers,~~ Load-Serving Entity~~Entities, and Purchasing-Selling Entities~~ shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s),~~Reliability Coordinator directives~~ unless such action~~actions~~ would violate safety, equipment, ~~or~~ regulatory, or statutory requirements. TOP-001-2 has been approved by ~~Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of~~ the NERC Board of Trustees and will be filed with~~inability to perform~~ the Commission for approval; therefore, TOP-001-1a R3 is presented for informational purposes only. ~~directive so that the Reliability Coordinator may implement alternate remedial actions.~~

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~~*The next proposed version of IRO-001 for this requirement also reads the same. As is apparent from a comparison of the two requirements, there is no need for TOP-001-1a R3 which is duplicative of IRO-001-1a R8. Also, in the next proposed version of TOP-001, Reliability Coordinator has been deleted from this requirement.~~

~~**Conclusion:** Requirement 3 is redundant to Reliability Standard IRO-001-1a R8 and should be removed from Reliability Standard TOP-001-1a.~~

TOP-005-2a R1

As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."

Criterion B 3.

Statement:

TOP-005-2a R1 is better suited for ROP than reliability requirement. A review of Standards Development Project 2007-03 Real-time Transmission Operations indicates it proposes R1 of TOP-005-1 to be retired. As stated above in the context of TOP-001, this project was approved by the NERC Board of Trustees and will be filed with the Commission for approval; therefore, TOP-005-2a R1 is presented for informational purposes only.

Conclusion: Since TOP-005-2a R1 provides little protection to the BES and is purely documentation in nature, it should be removed.

VAR-001-2 R5

Each Purchasing-Selling Entity and Load Serving Entity shall arrange for (self-provide or purchase) reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; and controllable load– to satisfy its reactive requirements identified by its Transmission Service Provider.

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Criterion B 7.

Statement: VAR-001-2 R5 is redundant with FERC's pro forma open access transmission tariff (OATT) Specifically, the requirement provides for the PSE and LSE to arrange for reactive resources to satisfy the reactive requirements of the Transmission Service Provider, which is already required under Schedule No. 2 of the OATT.

Conclusion: Since VAR-001-2 R5 is redundant with requirements already under FERC's OATT, and, thus, it should be removed.

~~**VAR-002-WECC-1 R2; VAR-501-WECC-1 R2**~~

~~VAR-002-WECC-1 R2 Generator Operators and Transmission Operators shall have documentation identifying the number of hours excluded for each requirement R1.1 through R1.10.~~

~~VAR-501-WECC-1 R2 Generator Operators shall have documentation identifying the number of hours excluded for each requirement in R1.1 through R1.12.~~

~~Criterion B 3 and 4.~~

~~**Statement:** Communication of the status of AVR and PSS with the Transmission Operator may impact reliability, but not documenting or reporting out of this information to a Regional Entity. If the Regional Entity desires to review or track the AVR and PSS hours, such information should be collected via vehicles other than the Reliability Standards, such as Compliance Audits, Spot Checks and other compliance monitoring procedures.~~

~~**Conclusion:** For regulatory efficiency and since the requirements are purely documentation and reporting activities, Requirement 2 in Regional Reliability Standards VAR-002-WECC-1 and VAR-501-WECC-1 should be removed from the Standards.~~

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SAR Information

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☒	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of responsible entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☒	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☒	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.

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Reliability Functions		
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☒	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles		
Applicable Reliability Principles (Check all that apply).		
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.	
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.	
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.	
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.	
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.	
☒	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.	
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.	
☒	8. Bulk power systems shall be protected from malicious physical or cyber attacks.	
Does the proposed Standard comply with all of the following Market Interface Principles?		Enter (yes/no)
	1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

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Reliability and Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation

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Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

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From:	Guy V. Zito
To:	rscmembers
Cc:	grpStaff
Subject:	FW: Standards Committee Executive Committee Approved P81 Posting
Date:	Friday, September 28, 2012 4:57:04 PM

To All,

During the Standards Committee Executive Committee teleconference today David Kiguel reported their following activity:

Authorize (a) waiving the 30 day initial comment period and (b) posting the SAR and list of requirements proposed for retirement in phase 1 for a 45-day formal comment period with the formation of a ballot pool during the first 30 days and an initial ballot during the last 10 days of that 45-day comment period. The balloting will be conducted as ONE single ballot for all 38 requirements.

I am trying to obtain further information regarding formalization of a Standards Drafting Team and whether this constitutes a variance in process.

Thanks,

Guy

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan
Project 2013-02 – Paragraph 81

Requested Approvals

- None

Requested Retirements

- BAL-005-0.2b R2
- CIP-001-2a R4
- CIP-003-3 R1.2
- CIP-003-3 R3
- CIP-003-3 R3.1
- CIP-003-3 R3.2
- CIP-003-3 R3.3
- CIP-003-3 R4.2
- CIP-003-4 R1.2
- CIP-003-4 R3
- CIP-003-4 R3.1
- CIP-003-4 R3.2
- CIP-003-4 R3.3
- CIP-003-4 R4.2
- CIP-005-3a R2.6
- CIP-005-4a R2.6
- CIP-007-3 R7.3
- CIP-007-4 R7.3
- EOP-004-1 R1
- EOP-005-2 R3.1
- FAC-002-1 R2
- FAC-008-1 R2
- FAC-008-1 R3
- FAC-008-3 R4
- FAC-008-3 R5
- FAC-010-2.1 R5
- FAC-011-2 R5
- FAC-013-2 R3
- INT-007-1 R1.2
- IRO-016-1 R2
- NUC-001-2 R9.1
- NUC-001-2 R9.1.1
- NUC-001-2 R9.1.2
- NUC-001-2 R9.1.3
- NUC-001-2 R9.1.4
- PRC-010-0 R2
- PRC-022-1 R2
- VAR-001-2 R5

Note that when these Requirements are retired, the version numbers of the standards will NOT be incremented, but the retired Requirements and associated elements will be clearly marked as retired. After evaluating the options and consulting with the Standards Committee and Standards Committee Process Subcommittee, the P81 drafting team determined that this was the most practical approach. Incrementing the version numbers of each standard is impractical because, in some cases, a subsequent version has already been developed. In addition, incrementing the version would require renumbering Requirements where a retired Requirement created a gap in numbering, and this creates an undesirable administrative burden for entities using certain systems to manage their compliance programs.

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

- None

Background

On September 30, 2011, the North American Electric Reliability Corporation (NERC) filed a petition with the Federal Energy Regulatory Commission (FERC) requesting approval of its proposal to make informational filings in a "Find, Fix, Track and Report" (FFT) spreadsheet of lesser-risk, remediated possible violations of Reliability Standards. On March 15, 2012, the FERC issued an order conditionally accepting NERC's FFT proposal. In paragraph 81 (P81) of that order, the FERC stated:

> The Commission notes that NERC's FFT initiative is predicated on the view that many violations of requirements currently included in Reliability Standards pose lesser risk to the Bulk-Power System. If so, some current requirements likely provide little protection for Bulk-Power System reliability or may be redundant. The Commission is interested in obtaining views on whether such requirements could be removed from the Reliability Standards with little effect on reliability and an increase in efficiency of the ERO compliance program. If NERC believes that specific Reliability Standards or specific requirements within certain Standards should be revised or removed, we invite NERC to make specific proposals to the Commission identifying the Standards or requirements and setting forth in detail the technical basis for its belief. In addition, or in the alternative, we invite NERC, the Regional Entities and other interested entities to propose appropriate mechanisms to identify and remove from the Commission-approved Reliability Standards unnecessary or redundant requirements. We will not impose a deadline on when these comments should be submitted, but ask that to the extent such comments are submitted NERC, the Regional Entities, and interested entities coordinate to submit their respective comments concurrently. North American Electric Reliability Corporation, 138 FERC ¶ 61,193 at p 81 (March 15, 2012) ("P81").

Consistent with P81, a draft Standards Authorization Request (SAR) was drafted to set forth criteria and a process to identify Reliability Standard requirements that either: (a) provide little protection to the Bulk Electric System; (b) are unnecessary or (c) are redundant; and, thereafter, to have NERC file the identified Reliability Standard requirements with FERC to have them removed from the FERC-approved list of Reliability Standards.

Standards Process Input Group (SPIG)

In addition to addressing P81, the draft SAR was drafted consistent with what the SPIG developed as Recommendation No. 4, as set forth in NERC's Recommendations to Improve The Standards Development Process on page 12 (April 2012), which states:

> Recommendation 4: Standards Product Issues — The NERC board is encouraged to require that the standards development process address: . . . The retirement of standards no longer needed to meet an adequate level of reliability.

Collaborative Process

The draft SAR and a suggested list of Reliability Standard requirements embedded in the SAR for consideration in the Initial Phase was the product of collaborative discussions among the following entities and their members: Edison Electric Institute, American Public Power Association, National Rural Electric Cooperative Association, Large Public Power Council, Electricity Consumers Resource Council, The Electric Power Supply Association, Transmission Access Policy Study Group, the North American Electric Reliability Corporation, and the Regional Entity Management Group. The draft SAR was posted for comment, which were due September 4, 2012. The P81 Standards Drafting Team reviewed the comments and finalized the SAR and the proposed list of Reliability Standard requirements for retirement.

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Interchange Authority
- Load Serving Entity
- NERC
- Planning Authority
- Planning Coordinator
- Purchasing-Selling Entity
- Regional Entity
- Regional Reliability Organization
- Reliability Coordinator
- Transmission Service Provider
- Transmission Operator
- Transmission Owner
- Transmission Planner

Effective Date of Retirements

All of the Requirements will be retired on the day of approval by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the first day of the first calendar quarter approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Note that no complete standard is being proposed for retirement and all of the other Requirements in each of the affected standards will remain in continuous effect until such time that the entire standard may be retired.

Standard Version	Requirement Name	Status	Requirement Text
BAL-005-0.2b	R2.	Kept in Final SAR for Retirement	Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.
CIP-001-2a	R4.	Kept in Final SAR for Retirement	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.
CIP-003-3	R1.2.	Kept in Final SAR for Retirement	The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.
CIP-003-3	R3.	Kept in Final SAR for Retirement	Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).
CIP-003-3	R3.1.	Kept in Final SAR for Retirement	Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).
CIP-003-3	R3.2.	Kept in Final SAR for Retirement	Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures.
CIP-003-3	R3.3.	Kept in Final SAR for Retirement	Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.
CIP-003-3	R4.2.	Kept in Final SAR for Retirement	The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.
CIP-003-4	R1.2.	Kept in Final SAR for Retirement	The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.
CIP-003-4	R3.	Kept in Final SAR for Retirement	Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).
CIP-003-4	R3.1.	Kept in Final SAR for Retirement	Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).
CIP-003-4	R3.2.	Kept in Final SAR for Retirement	Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures.
CIP-003-4	R3.3.	Kept in Final SAR for Retirement	Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.
CIP-003-4	R4.2.	Kept in Final SAR for Retirement	The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.

Standard Version	Requirement Name	Status	Requirement Text
CIP-005-3a	R2.6.	Kept in Final SAR for Retirement	Appropriate Use Banner —Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.
CIP-005-4a	R2.6.	Kept in Final SAR for Retirement	Appropriate Use Banner —Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.
CIP-007-3	R7.3.	Kept in Final SAR for Retirement	The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.
CIP-007-4	R7.3.	Kept in Final SAR for Retirement	The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.
COM-001-1.1	R6.	Kept in Final SAR for Information Only	Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001, "NERCNet Security Policy."
EOP-004-1	R1.	Kept in Final SAR for Retirement	Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.
EOP-005-2	R3.1.	Kept in Final SAR for Retirement	If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary.
EOP-009-0	R2.	Kept in Final SAR for Information Only	The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating unit to the Regional Reliability Organizations and upon request to NERC.
FAC-002-1	R2.	Kept in Final SAR for Retirement	The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) and NERC on request (within 30 calendar days).
FAC-008-1	R1.3.5.	Kept in Final SAR for Information Only	Other assumptions.
FAC-008-1	R2.	Kept in Final SAR for Retirement	The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.

Standard Version	Requirement Name	Status	Requirement Text
FAC-008-1	R3.	Kept in Final SAR for Retirement	If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.
FAC-008-3	R4.	Kept in Final SAR for Retirement	Each Transmission Owner shall make its Facility Ratings methodology and each Generator Owner shall each make its documentation for determining its Facility Ratings and its Facility Ratings methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners and Planning Coordinators that have responsibility for the area in which the associated Facilities are located, within 21 calendar days of receipt of a request.
FAC-008-3	R5.	Kept in Final SAR for Retirement	If a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Coordinator provides documented comments on its technical review of a Transmission Owner's Facility Ratings methodology or Generator Owner's documentation for determining its Facility Ratings and its Facility Rating methodology, the Transmission Owner or Generator Owner shall provide a response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings methodology and, if no change will be made to that Facility Ratings methodology, the reason why.
FAC-010-2.1	R5.	Added to Final SAR for Retirement	If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.
FAC-011-2	R5.	Added to Final SAR for Retirement	If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

Standard Version	Requirement Name	Status	Requirement Text
FAC-013-2	R3.	Kept in Final SAR for Retirement	If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why.
INT-007-1	R1.2.	Kept in Final SAR for Retirement	All reliability entities involved in the Arranged Interchange are currently in the NERC registry.
IRO-016-1	R2.	Kept in Final SAR for Retirement	The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.
MOD-004-1	R1.	Deferred to Subsequent Phase	The Transmission Service Provider that maintains CBM shall prepare and keep current a "Capacity Benefit Margin Implementation Document" (CBMID) that includes, at a minimum, the following information:
MOD-004-1	R1.1.	Deferred to Subsequent Phase	The process through which a Load-Serving Entity within a Balancing Authority Area associated with the Transmission Service Provider, or the Resource Planner associated with that Balancing Authority Area, may ensure that its need for Transmission capacity to be set aside as CBM will be reviewed and accommodated by the Transmission Service Provider to the extent Transmission capacity is available.
MOD-004-1	R1.2.	Deferred to Subsequent Phase	The procedure and assumptions for establishing CBM for each Available Transfer Capability (ATC) Path or Flowgate.
MOD-004-1	R1.3.	Deferred to Subsequent Phase	The procedure for a Load-Serving Entity or Balancing Authority to use Transmission capacity set aside as CBM, including the manner in which the Transmission Service Provider will manage situations where the requested use of CBM exceeds the amount of CBM available.
MOD-004-1	R2.	Deferred to Subsequent Phase	The Transmission Service Provider that maintains CBM shall make available its current CBMID to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, Resource Planners, and Planning Coordinators that are within or adjacent to the Transmission Service Provider's area, and to the Load Serving Entities and Balancing Authorities within the Transmission Service Provider's area, and notify those entities of any changes to the CBMID prior to the effective date of the change.
MOD-004-1	R3.	Deferred to Subsequent Phase	Each Load-Serving Entity determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by:

Standard Version	Requirement Name	Status	Requirement Text
MOD-004-1	R3.1.	Deferred to Subsequent Phase	Using one or more of the following to determine the GCIR: Loss of Load Expectation (LOLE) studies; Loss of Load Probability (LOLP) studies; Deterministic risk-analysis studies; Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities
MOD-004-1	R3.2.	Deferred to Subsequent Phase	Identifying expected import path(s) or source region(s).
MOD-004-1	R4.	Deferred to Subsequent Phase	Each Resource Planner determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by:
MOD-004-1	R4.1.	Deferred to Subsequent Phase	Using one or more of the following to determine the GCIR: Loss of Load Expectation (LOLE) studies; Loss of Load Probability (LOLP) studies; Deterministic risk-analysis studies; Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities
MOD-004-1	R4.2.	Deferred to Subsequent Phase	Identifying expected import path(s) or source region(s).
MOD-004-1	R5.	Deferred to Subsequent Phase	At least every 13 months, the Transmission Service Provider that maintains CBM shall establish a CBM value for each ATC Path or Flowgate to be used for ATC or Available Flowgate Capability (AFC) calculations during the 13 full calendar months (months 2-14) following the current month (the month in which the Transmission Service Provider is establishing the CBM values). This value shall:
MOD-004-1	R5.1.	Deferred to Subsequent Phase	Reflect consideration of each of the following if available: Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Service Provider's area; Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Service Provider’s area; Any reserve margin or resource adequacy requirements for loads within the Transmission Service Provider’s area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities
MOD-004-1	R5.2.	Deferred to Subsequent Phase	Be allocated as follows: For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners; For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Service Provider

Standard Version	Requirement Name	Status	Requirement Text
MOD-004-1	R6.	Deferred to Subsequent Phase	At least every 13 months, the Transmission Planner shall establish a CBM value for each ATC Path or Flowgate to be used in planning during each of the full calendar years two through ten following the current year (the year in which the Transmission Planner is establishing the CBM values). This value shall:
MOD-004-1	R6.1.	Deferred to Subsequent Phase	Reflect consideration of each of the following if available: Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Planner's area; Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Planner's area; Any reserve margin or resource adequacy requirements for loads within the Transmission Planner's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities
MOD-004-1	R6.2.	Deferred to Subsequent Phase	Be allocated as follows: For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners; For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Planner.
MOD-004-1	R7.	Deferred to Subsequent Phase	Less than 31 calendar days after the establishment of CBM, the Transmission Service Provider that maintains CBM shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the Transmission Service Provider's system of the amount of CBM set aside.
MOD-004-1	R8.	Deferred to Subsequent Phase	Less than 31 calendar days after the establishment of CBM, the Transmission Planner shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the system being planned by the Transmission Planner of the amount of CBM set aside.
MOD-004-1	R9.	Deferred to Subsequent Phase	The Transmission Service Provider that maintains CBM and the Transmission Planner shall each provide (subject to confidentiality and security requirements) copies of the applicable supporting data, including any models, used for determining CBM or allocating CBM over each ATC Path or Flowgate to the following:
MOD-004-1	R10.	Deferred to Subsequent Phase	The Load-Serving Entity or Balancing Authority shall request to import energy over firm Transfer Capability set aside as CBM only when experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher.
MOD-004-1	R11.	Deferred to Subsequent Phase	When reviewing an Arranged Interchange using CBM, all Balancing Authorities and Transmission Service Providers shall waive, within the bounds of reliable operation, any Real-time timing and ramping requirements.

Standard Version	Requirement Name	Status	Requirement Text
MOD-004-1	R12.	Deferred to Subsequent Phase	The Transmission Service Provider that maintains CBM shall approve, within the bounds of reliable operation, any Arranged Interchange using CBM that is submitted by an "energy deficient entity" under an EEA 2 if:
MOD-004-1	R12.1.	Deferred to Subsequent Phase	The CBM is available
MOD-004-1	R12.2.	Deferred to Subsequent Phase	The EEA 2 is declared within the Balancing Authority Area of the "energy deficient entity," and
MOD-004-1	R12.3.	Deferred to Subsequent Phase	The Load of the "energy deficient entity" is located within the Transmission Service Provider's area.
MOD-004-1	R9.1.	Deferred to Subsequent Phase	Each of its associated Transmission Operators within 30 calendar days of their making a request for the data.
MOD-004-1	R9.2.	Deferred to Subsequent Phase	To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, Resource Planner, or Planning Coordinator within 30 calendar days of their making a request for the data.
NUC-001-2	R9.1.	Kept in Final SAR for Retirement	Administrative elements:
NUC-001-2	R9.1.1.	Kept in Final SAR for Retirement	Definitions of key terms used in the agreement.
NUC-001-2	R9.1.2.	Kept in Final SAR for Retirement	Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs.
NUC-001-2	R9.1.3.	Kept in Final SAR for Retirement	A requirement to review the agreement(s) at least every three years.
NUC-001-2	R9.1.4.	Kept in Final SAR for Retirement	A dispute resolution mechanism.
PRC-008-0	R1.	Kept in Final SAR for Information Only	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.
PRC-008-0	R2.	Kept in Final SAR for Information Only	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).
PRC-009-0	R1.	Kept in Final SAR for Information Only	The Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:

Standard Version	Requirement Name	Status	Requirement Text
PRC-009-0	R1.1.	Kept in Final SAR for Information Only	A description of the event including initiating conditions.
PRC-009-0	R1.2.	Kept in Final SAR for Information Only	A review of the UFLS set points and tripping times.
PRC-009-0	R1.3.	Kept in Final SAR for Information Only	A simulation of the event.
PRC-009-0	R1.4.	Kept in Final SAR for Information Only	A summary of the findings.
PRC-009-0	R2.	Kept in Final SAR for Information Only	The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.
PRC-010-0	R2.	Kept in Final SAR for Retirement	The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days).
PRC-022-1	R2.	Kept in Final SAR for Retirement	Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90 calendar days of a request.
TOP-001-1a	R3.	Kept in Final SAR for Information Only	Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.
TOP-005-2a	R1.	Kept in Final SAR for Information Only	As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for “Electric System Reliability Data.”

Standard Version	Requirement Name	Status	Requirement Text
VAR-001-2	R5.	Added to Final SAR for Retirement	Each Purchasing-Selling Entity and Load Serving Entity shall arrange for (self-provide or purchase) reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load– to satisfy its reactive requirements identified by its Transmission Service Provider.
VAR-002-WECC-1	R2.	Deferred to Subsequent Phase	Generator Operators and Transmission Operators shall have documentation identifying the number of hours excluded for each requirement in R1.1 through R1.10.
VAR-501-WECC-1	R2.	Deferred to Subsequent Phase	Generator Operators shall have documentation identifying the number of hours excluded for each requirement in R1.1 through R1.12.

A. Introduction

1. **Title:** **Automatic Generation Control**

2. **Number:** BAL-005-0.2b

3. **Purpose:** This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Generator Operators

   4.3. Transmission Operators

   4.4. Load Serving Entities

5. **Effective Date:** May 13, 2009

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard. (Retired)

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

R6. The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

R7. The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.

R8. The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.

R8.1. Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

R9. The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.

R9.1. Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

R10. The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.

R11. Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.

R12. Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.

R12.1. Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.

R12.2. Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.

R12.3. Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.

R13. Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.

R14. The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.

R15. The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical

locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

R16. The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale
Remote terminal unit	≤ 0.25 % of full scale
Potential transformer	≤ 0.30 % of full scale
Current transformer	≤ 0.50 % of full scale

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

1.1.1. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.

1.1.2. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

1.3.1. Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.

1.3.2. Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or

Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 — Interpretation of Requirement R17 (February 12, 2008).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008 (BOT approved retirement of Interpretation included in BAL-005-0a)	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to "0.1b"	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date	Addition
0.2b	March 8, 2012	Errata adopted by Standards Committee; (replaced Appendix 1 with the FERC-approved revised interpretation of R17 and corrected standard version referenced in Interpretation by changing from "BAL-005-1" to "BAL-005-0)	Errata
0.2b	September 13, 2012	FERC approved – Updated Effective Date	Addition
0.2b	TBD	R2 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

Appendix 1

Effective Date: August 27, 2008 (U.S.)

Interpretation of BAL-005-0 Automatic Generation Control, R17

Request for Clarification received from PGE on July 31, 2007

PGE requests clarification regarding the measuring devices for which the requirement applies, specifically clarification if the requirement applies to the following measuring devices:

- *Only equipment within the operations control room*
- *Only equipment that provides values used to calculate AGC ACE*
- *Only equipment that provides values to its SCADA system*
- *Only equipment owned or operated by the BA*
- *Only to new or replacement equipment*
- *To all equipment that a BA owns or operates*

BAL-005-0

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25% of full scale
Remote terminal unit	≤ 0.25% of full scale
Potential transformer	≤ 0.30% of full scale
Current transformer	≤ 0.50% of full scale

Existing Interpretation Approved by Board of Trustees May 2, 2007

BAL-005-0, Requirement 17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to "annually check and calibrate" does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to "annually check and calibrate" the devices listed in the table, unless they are included in the control center time error and frequency devices.

Interpretation provided by NERC Frequency Task Force on September 7, 2007 and Revised on November 16, 2007

As noted in the existing interpretation, BAL-005-0 Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system

operator. Frequency inputs from other sources that are for reference only are excluded. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17. The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements.

New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy.

A. Introduction

1. **Title:** **Sabotage Reporting**

2. **Number:** CIP-001-2a

3. **Purpose:** Disturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies.

4. **Applicability**

   4.1. Reliability Coordinators.

   4.2. Balancing Authorities.

   4.3. Transmission Operators.

   4.4. Generator Operators.

   4.5. Load Serving Entities.

   4.6. Transmission Owners (only in ERCOT Region).

   4.7. Generator Owners (only in ERCOT Region).

5. **Effective Date:** ERCOT Regional Variance will be effective the first day of the first calendar quarter after applicable regulatory approval.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection.

R2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances. (Retired)

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request a procedure (either electronic or hard copy) as defined in Requirement 1

M2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request the procedures or guidelines that will be used to confirm that it meets Requirements 2 and 3.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to procedures, policies, a letter of understanding, communication records, or other equivalent evidence that will be used to confirm that it has established communications contacts with the applicable, local FBI or RCMP officials to communicate sabotage events (Requirement 4). (Retired)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to verify compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Reliability Coordinator, Transmission Operator, Generator Operator, Distribution Provider, and Load Serving Entity shall have current, in-force documents available as evidence of compliance as specified in each of the Measures.

If an entity is found non-compliant the entity shall keep information related to the non-compliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance:

2.1. Level 1: There shall be a separate Level 1 non-compliance, for every one of the following requirements that is in violation:

2.1.1 Does not have procedures for the recognition of and for making its operating personnel aware of sabotage events (R1).

2.1.2 Does not have procedures or guidelines for the communication of information concerning sabotage events to appropriate parties in the Interconnection (R2).

2.1.3 Has not established communications contacts, as specified in R4. (Retired)

2.2. Level 2: Not applicable.

2.3. Level 3: Has not provided its operating personnel with sabotage response procedures or guidelines (R3).

2.4. Level 4:.Not applicable.

E. ERCOT Interconnection-wide Regional Variance

Requirements

EA.1. Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection.

EA.2. Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.

EA.3. Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.

EA.4. Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall establish communications contacts with local Federal Bureau of Investigation (FBI) officials and develop reporting procedures as appropriate to their circumstances. (Retired)

Measures

M.A.1. Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall have and provide upon request a procedure (either electronic or hard copy) as defined in Requirement EA1.

M.A.2. Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall have and provide upon request the procedures or guidelines that will be used to confirm that it meets Requirements EA2 and EA3.

M.A.3. Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, procedures, policies, a letter of understanding, communication records,

or other equivalent evidence that will be used to confirm that it has established communications contacts with the local FBI officials to communicate sabotage events (Requirement EA4). (Retired)

Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity shall be responsible for compliance monitoring.

1.2. Data Retention

Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall have current, in-force documents available as evidence of compliance as specified in each of the Measures.

If an entity is found non-compliant the entity shall keep information related to the non-compliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Amended
1	April 4, 2007	Regulatory Approval — Effective Date	New
1a	February 16, 2010	Added Appendix 1 — Interpretation of R2 approved by the NERC Board of Trustees	Addition
1a	February 2, 2011	Interpretation of R2 approved by FERC on February 2, 2011	Same addition
	June 10, 2010	TRE regional ballot approved variance	By Texas RE
	August 24, 2010	Regional Variance Approved by Texas RE Board of Directors	
2a	February 16, 2011	Approved by NERC Board of Trustees	

2a	August 2, 2011	FERC Order issued approving Texas RE Regional Variance	
2a	TBD	R4 and EA.4 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

Appendix 1

Requirement Number and Text of Requirement
CIP-001-1: **R2**. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.
Question
Please clarify what is meant by the term, "appropriate parties." Moreover, who within the Interconnection hierarchy deems parties to be appropriate?
Response
The drafting team interprets the phrase "appropriate parties in the Interconnection" to refer collectively to entities with whom the reporting party has responsibilities and/or obligations for the communication of physical or cyber security event information. For example, reporting responsibilities result from NERC standards IRO-001 Reliability Coordination — Responsibilities and Authorities, COM-002-2 Communication and Coordination, and TOP-001 Reliability Responsibilities and Authorities, among others. Obligations to report could also result from agreements, processes, or procedures with other parties, such as may be found in operating agreements and interconnection agreements. The drafting team asserts that those entities to which communicating sabotage events is appropriate would be identified by the reporting entity and documented within the procedure required in CIP-001-1 Requirement R2. Regarding "who within the Interconnection hierarchy deems parties to be appropriate," the drafting team knows of no interconnection authority that has such a role.

A. Introduction

1. Title: Cyber Security — Security Management Controls

2. Number: CIP-003-3

3. Purpose: Standard CIP-003-3 requires that Responsible Entities have minimum security management controls in place to protect Critical Cyber Assets. Standard CIP-003-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. Applicability:

4.1. Within the text of Standard CIP-003-3, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator.

4.1.2 Balancing Authority.

4.1.3 Interchange Authority.

4.1.4 Transmission Service Provider.

4.1.5 Transmission Owner.

4.1.6 Transmission Operator.

4.1.7 Generator Owner.

4.1.8 Generator Operator.

4.1.9 Load Serving Entity.

4.1.10 NERC.

4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-003-3:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets shall only be required to comply with CIP-003-3 Requirement R2.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:

R1.1. The cyber security policy addresses the requirements in Standards CIP-002-3 through CIP-009-3, including provision for emergency situations.

R1.2. The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets. (Retired)

R1.3. Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.

R2. Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity's implementation of, and adherence to, Standards CIP-002-3 through CIP-009-3.

R2.1. The senior manager shall be identified by name, title, and date of designation.

R2.2. Changes to the senior manager must be documented within thirty calendar days of the effective date.

R2.3. Where allowed by Standards CIP-002-3 through CIP-009-3, the senior manager may delegate authority for specific actions to a named delegate or delegates. These delegations shall be documented in the same manner as R2.1 and R2.2, and approved by the senior manager.

R2.4. The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.

R3. Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s). (Retired)

R3.1. Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s). (Retired)

R3.2. Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures. (Retired)

R3.3. Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented. (Retired)

R4. Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.

R4.1. The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002-3, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.

R4.2. The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information. (Retired)

R4.3. The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.

R5. Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.

R5.1. The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.

R5.1.1. Personnel shall be identified by name, title, and the information for which they are responsible for authorizing access.

R5.1.2. The list of personnel responsible for authorizing access to protected information shall be verified at least annually.

R5.2. The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.

R5.3. The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.

R6. Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendor-related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.

C. Measures

M1. The Responsible Entity shall make available documentation of its cyber security policy as specified in Requirement R1. Additionally, the Responsible Entity shall demonstrate that the cyber security policy is available as specified in Requirement R1.2. (R1.2 retired)

M2. The Responsible Entity shall make available documentation of the assignment of, and changes to, its leadership as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of the exceptions, as specified in Requirement R3. (Retired)

M4. The Responsible Entity shall make available documentation of its information protection program as specified in Requirement R4.

M5. The Responsible Entity shall make available its access control documentation as specified in Requirement R5.

M6. The Responsible Entity shall make available its change control and configuration management documentation as specified in Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Requirement R2 applies to all Responsible Entities, including Responsible Entities which have no Critical Cyber Assets. Modified the personnel identification information requirements in R5.1.1 to include name, title, and the information for which they are responsible for authorizing access (removed the business phone information). Changed compliance monitor to Compliance Enforcement Authority.	
3		Update version number from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	Update

	3	TBD	R1.2, R3, R3.1, R3.2, R3.3, and R4.2 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

A. Introduction

1. Title: Cyber Security — Security Management Controls

2. Number: CIP-003-4

3. Purpose: Standard CIP-003-4 requires that Responsible Entities have minimum security management controls in place to protect Critical Cyber Assets. Standard CIP-003-4 should be read as part of a group of standards numbered Standards CIP-002-4 through CIP-009-4.

4. Applicability:

4.1. Within the text of Standard CIP-003-4, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator.

4.1.2 Balancing Authority.

4.1.3 Interchange Authority.

4.1.4 Transmission Service Provider.

4.1.5 Transmission Owner.

4.1.6 Transmission Operator.

4.1.7 Generator Owner.

4.1.8 Generator Operator.

4.1.9 Load Serving Entity.

4.1.10 NERC.

4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-003-4:

4.2.1 Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 In nuclear plants, the systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F. R. Section 73.54

4.2.4 Responsible Entities that, in compliance with Standard CIP-002-4, identify that they have no Critical Cyber Assets shall only be required to comply with CIP-003-4 Requirement R2.

5. Effective Date: The first day of the eighth calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the ninth calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:

R1.1. The cyber security policy addresses the requirements in Standards CIP-002-4 through CIP-009-4, including provision for emergency situations.

R1.2. The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets. (Retired)

R1.3. Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.

R2. Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity's implementation of, and adherence to, Standards CIP-002-4 through CIP-009-4.

R2.1. The senior manager shall be identified by name, title, and date of designation.

R2.2. Changes to the senior manager must be documented within thirty calendar days of the effective date.

R2.3. Where allowed by Standards CIP-002-4 through CIP-009-4, the senior manager may delegate authority for specific actions to a named delegate or delegates. These delegations shall be documented in the same manner as R2.1 and R2.2, and approved by the senior manager.

R2.4. The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.

R3. Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s). (Retired)

R3.1. Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s). (Retired)

R3.2. Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures. (Retired)

R3.3. Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented. (Retired)

R4. Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.

R4.1. The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002-4, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.

R4.2. The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information. (Retired)

R4.3. The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.

R5. Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.

R5.1. The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.

R5.1.1. Personnel shall be identified by name, title, and the information for which they are responsible for authorizing access.

R5.1.2. The list of personnel responsible for authorizing access to protected information shall be verified at least annually.

R5.2. The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.

R5.3. The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.

R6. Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendor-related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.

C. Measures

M1. The Responsible Entity shall make available documentation of its cyber security policy as specified in Requirement R1. Additionally, the Responsible Entity shall demonstrate that the cyber security policy is available as specified in Requirement R1.2. (R1.2 retired)

M2. The Responsible Entity shall make available documentation of the assignment of, and changes to, its leadership as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of the exceptions, as specified in Requirement R3. (Retired)

M4. The Responsible Entity shall make available documentation of its information protection program as specified in Requirement R4.

M5. The Responsible Entity shall make available its access control documentation as specified in Requirement R5.

M6. The Responsible Entity shall make available its change control and configuration management documentation as specified in Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.2. The RE shall serve as the CEA with the following exceptions:

1.2.1 For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

1.2.2 For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2.3 For Responsible Entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2.4 For the ERO, a third-party monitor without vested interest in the outcome for the ERO shall serve as the Compliance Enforcement Authority.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None

2. Violation Severity Levels

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	MEDIUM	N/A	N/A	The Responsible Entity has documented but not implemented a cyber security policy.	The Responsible Entity has not documented nor implemented a cyber security policy.
R1.1.	LOWER	N/A	N/A	N/A	The Responsible Entity's cyber security policy does not address all the requirements in Standards CIP-002-4 through CIP-009-4, including provision for emergency situations.
R1.2. (Retired)	LOWER	N/A	N/A	N/A	The Responsible Entity's cyber security policy is not readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.
R1.3	LOWER	N/A	N/A	The Responsible Entity's senior manager, assigned pursuant to R2, annually reviewed but did not annually approve its cyber security policy.	The Responsible Entity's senior manager, assigned pursuant to R2, did not annually review nor approve its cyber security policy.
R2.	LOWER	N/A	N/A	N/A	The Responsible Entity has not assigned a single senior manager with overall responsibility and authority for leading and managing the entity's implementation of, and adherence to, Standards CIP-002-4 through CIP-009-4.
R2.1.	LOWER	N/A	N/A	N/A	The senior manager is not identified by name, title, and date of designation.
R2.2.	LOWER	Changes to the senior manager were documented in greater than 30 but less than 60 days of the effective date.	Changes to the senior manager were documented in 60 or more but less than 90 days of the effective date.	Changes to the senior manager were documented in 90 or more but less than 120 days of the effective date.	Changes to the senior manager were documented in 120 or more days of the effective date.
R2.3.	LOWER	N/A	N/A	The identification of a senior manager's delegate does not include at least one of the following; name, title, or date of the designation, OR The document is not approved by the senior manager, OR Changes to the delegated authority are not documented	A senior manager's delegate is not identified by name, title, and date of designation; the document delegating the authority does not identify the authority being delegated; the document delegating the authority is not approved by the senior manager; AND changes to the delegated authority are not documented within thirty calendar days of the effective date.

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
				within thirty calendar days of the effective date.	
R2.4	LOWER	N/A	N/A	N/A	The senior manager or delegate(s) did not authorize and document any exceptions from the requirements of the cyber security policy as required.
R3. (Retired)	LOWER	N/A	N/A	In Instances where the Responsible Entity cannot conform to its cyber security policy (pertaining to CIP 002 through CIP 009), exceptions were documented, but were not authorized by the senior manager or delegate(s).	In Instances where the Responsible Entity cannot conform to its cyber security policy (pertaining to CIP 002 through CIP 009), exceptions were not documented, and were not authorized by the senior manager or delegate(s).
R3.1. (Retired)	LOWER	Exceptions to the Responsible Entity's cyber security policy were documented in more than 30 but less than 60 days of being approved by the senior manager or delegate(s).	Exceptions to the Responsible Entity's cyber security policy were documented in 60 or more but less than 90 days of being approved by the senior manager or delegate(s).	Exceptions to the Responsible Entity's cyber security policy were documented in 90 or more but less than 120 days of being approved by the senior manager or delegate(s).	Exceptions to the Responsible Entity's cyber security policy were documented in 120 or more days of being approved by the senior manager or delegate(s).
R3.2. (Retired)	LOWER	N/A	N/A	The Responsible Entity has a documented exception to the cyber security policy (pertaining to CIP 002-4 through CIP 009-4) but did not include either: 1) an explanation as to why the exception is necessary, or 2) any compensating measures.	The Responsible Entity has a documented exception to the cyber security policy (pertaining to CIP 002-4 through CIP 009-4) but did not include both: 1) an explanation as to why the exception is necessary, and 2) any compensating measures.
R3.3. (Retired)	LOWER	N/A	N/A	Exceptions to the cyber security policy (pertaining to CIP 002-4 through CIP 009-4) were reviewed but not approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid.	Exceptions to the cyber security policy (pertaining to CIP 002-4 through CIP 009-4) were not reviewed nor approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid.
R4.	MEDIUM	N/A	The Responsible Entity implemented but did not document a program to identify, classify, and protect information associated with Critical Cyber Assets.	The Responsible Entity documented but did not implement a program to identify, classify, and protect information associated with Critical Cyber Assets.	The Responsible Entity did not implement nor document a program to identify, classify, and protect information associated with Critical Cyber Assets.
R4.1.	MEDIUM	N/A	N/A	The information protection program does not include one of the minimum information types to be protected as detailed in R4.1.	The information protection program does not include two or more of the minimum information types to be protected as detailed in R4.1.

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.2. (Retired)	LOWER	N/A	N/A	N/A	The Responsible Entity did not classify the information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.
R4.3.	LOWER	N/A	The Responsible Entity annually assessed adherence to its Critical Cyber Asset information protection program, documented the assessment results, which included deficiencies identified during the assessment but did not implement a remediation plan.	The Responsible Entity annually assessed adherence to its Critical Cyber Asset information protection program, did not document the assessment results, and did not implement a remediation plan.	The Responsible Entity did not annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, nor implement an action plan to remediate deficiencies identified during the assessment.
R5.	LOWER	N/A	The Responsible Entity implemented but did not document a program for managing access to protected Critical Cyber Asset information.	The Responsible Entity documented but did not implement a program for managing access to protected Critical Cyber Asset information.	The Responsible Entity did not implement nor document a program for managing access to protected Critical Cyber Asset information.
R5.1.	LOWER	N/A	N/A	The Responsible Entity maintained a list of designated personnel for authorizing either logical or physical access but not both.	The Responsible Entity did not maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.
R5.1.1.	LOWER	N/A	N/A	The Responsible Entity did identify the personnel by name and title but did not identify the information for which they are responsible for authorizing access.	The Responsible Entity did not identify the personnel by name and title nor the information for which they are responsible for authorizing access.
R5.1.2.	LOWER	N/A	N/A	N/A	The Responsible Entity did not verify at least annually the list of personnel responsible for authorizing access to protected information.
R5.2.	LOWER	N/A	N/A	N/A	The Responsible Entity did not review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.
R5.3.	LOWER	N/A	N/A	N/A	The Responsible Entity did not assess and document at least annually the processes for controlling access privileges to protected information.
R6.	LOWER	The Responsible Entity has established but not documented a change	The Responsible Entity has established but not documented both a change control process and configuration management	The Responsible Entity has not established and documented a change control process OR	The Responsible Entity has not established and documented a change control process AND

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
		control process OR The Responsible Entity has established but not documented a configuration management process.	process.	The Responsible Entity has not established and documented a configuration management process.	The Responsible Entity has not established and documented a configuration management process.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Requirement R2 applies to all Responsible Entities, including Responsible Entities which have no Critical Cyber Assets. Modified the personnel identification information requirements in R5.1.1 to include name, title, and the information for which they are responsible for authorizing access (removed the business phone information). Changed compliance monitor to Compliance Enforcement Authority.	
3		Update version number from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	Update
4	Board approved 01/24/2011	Update version number from “3” to “4”	Update to conform to changes to CIP-002-4 (Project 2008-06)
4	4/19/12	FERC Order issued approving CIP-003-4 (approval becomes effective June 25, 2012) Added approved VRF/VSL table to section D.2.	
3, 4	TBD	R1.2, R3, R3.1, R3.2, R3.3, and R4.2 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

A. Introduction

1. Title: Cyber Security — Electronic Security Perimeter(s)

2. Number: CIP-005-3a

3. Purpose: Standard CIP-005-3 requires the identification and protection of the Electronic Security Perimeter(s) inside which all Critical Cyber Assets reside, as well as all access points on the perimeter. Standard CIP-005-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. Applicability

4.1. Within the text of Standard CIP-005-3, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator.

4.1.2 Balancing Authority.

4.1.3 Interchange Authority.

4.1.4 Transmission Service Provider.

4.1.5 Transmission Owner.

4.1.6 Transmission Operator.

4.1.7 Generator Owner.

4.1.8 Generator Operator.

4.1.9 Load Serving Entity.

4.1.10 NERC.

4.1.11 Regional Entity

4.2. The following are exempt from Standard CIP-005-3:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s).

R1.1. Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).

R1.2. For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.

R1.3. Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).

R1.4. Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005-3.

R1.5. Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3 Requirement R3; Standard CIP-007-3 Requirements R1 and R3 through R9; Standard CIP-008-3; and Standard CIP-009-3.

R1.6. The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), all electronic access points to the Electronic Security Perimeter(s) and the Cyber Assets deployed for the access control and monitoring of these access points.

R2. Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).

R2.1. These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.

R2.2. At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and shall document, individually or by specified grouping, the configuration of those ports and services.

R2.3. The Responsible Entity shall implement and maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).

R2.4. Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.

R2.5. The required documentation shall, at least, identify and describe:

R2.5.1. The processes for access request and authorization.

R2.5.2. The authentication methods.

R2.5.3. The review process for authorization rights, in accordance with Standard CIP-004-3 Requirement R4.

R2.5.4. The controls used to secure dial-up accessible connections.

R2.6. Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner. (Retired)

R3. Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.

R3.1. For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.

R3.2. Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.

R4. Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following:

R4.1. A document identifying the vulnerability assessment process;

R4.2. A review to verify that only ports and services required for operations at these access points are enabled;

R4.3. The discovery of all access points to the Electronic Security Perimeter;

R4.4. A review of controls for default accounts, passwords, and network management community strings;

R4.5. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.

R5. Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005-3.

R5.1. The Responsible Entity shall ensure that all documentation required by Standard CIP-005-3 reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005-3 at least annually.

R5.2. The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.

R5.3. The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-3.

C. Measures

M1. The Responsible Entity shall make available documentation about the Electronic Security Perimeter as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation of the electronic access controls to the Electronic Security Perimeter(s), as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of controls implemented to log and monitor access to the Electronic Security Perimeter(s) as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation of its annual vulnerability assessment as specified in Requirement R4.

M5. The Responsible Entity shall make available access logs and documentation of review, changes, and log retention as specified in Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep logs for a minimum of ninety calendar days, unless: a) longer retention is required pursuant to Standard CIP-008-3, Requirement R2; b) directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Responsible Entity shall keep other documents and records required by Standard CIP-005-3 from the previous full calendar year.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	01/16/06	D.2.3.1 — Change “Critical Assets,” to “Critical Cyber Assets” as intended.	03/24/06
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Revised the wording of the Electronic Access Controls requirement stated in R2.3 to clarify that the Responsible Entity	

		shall “implement and maintain” a procedure for securing dial-up access to the Electronic Security Perimeter(s). Changed compliance monitor to Compliance Enforcement Authority.	
3		Update version from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	Update
3a	02/16/10	Added Appendix 1 – Interpretation of R1.3 approved by BOT on February 16, 2010	Interpretation
3a	02/02/11	Approved by FERC	
3a	TBD	R2.6 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

Appendix 1

Requirement Number and Text of Requirement
Section 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters. **Requirement R1.3** Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).
Question 1 (Section 4.2.2)
What kind of cyber assets are referenced in 4.2.2 as "associated"? What else could be meant except the devices forming the communication link?
Response to Question 1
In the context of applicability, associated Cyber Assets refer to any communications devices external to the Electronic Security Perimeter, i.e., beyond the point at which access to the Electronic Security Perimeter is controlled. Devices controlling access into the Electronic Security Perimeter are not exempt.
Question 2 (Section 4.2.2)
Is the communication link physical or logical? Where does it begin and terminate?
Response to Question 2
The drafting team interprets the data communication link to be physical or logical, and its termination points depend upon the design and architecture of the communication link.
Question 3 (Requirement R1.3)
Please clarify what is meant by an “endpoint”? Is it physical termination? Logical termination of OSI layer 2, layer 3, or above?
Response to Question 3
The drafting team interprets the endpoint to mean the device at which a physical or logical communication link terminates. The endpoint is the Electronic Security Perimeter access point if access into the Electronic Security Perimeter is controlled at the endpoint, irrespective of which Open Systems Interconnection (OSI) layer is managing the communication.
Question 4 (Requirement R1.3)
If “endpoint” is defined as logical and refers to layer 3 and above, please clarify if the termination points of an encrypted tunnel (layer 3) must be treated as an “access point? If two control centers are owned and managed by the same entity, connected via an encrypted link by properly applied Federal

Information Processing Standards, with tunnel termination points that are within the control center ESPs and PSPs and do not terminate on the firewall but on a separate internal device, and the encrypted traffic already passes through a firewall access point at each ESP boundary where port/protocol restrictions are applied, must these encrypted communication tunnel termination points be treated as "access points" in addition to the firewalls through which the encrypted traffic has already passed?
Response to Question 4
In the case where the “endpoint” is defined as logical and is >= layer 3, the termination points of an encrypted tunnel must be treated as an “access point.” The encrypted communication tunnel termination points referred to above are “access points.”

A. Introduction

1. Title: Cyber Security — Electronic Security Perimeter(s)

2. Number: CIP-005-4a

3. Purpose: Standard CIP-005-4a requires the identification and protection of the Electronic Security Perimeter(s) inside which all Critical Cyber Assets reside, as well as all access points on the perimeter. Standard CIP-005-4a should be read as part of a group of standards numbered Standards CIP-002-4 through CIP-009-4.

4. Applicability

4.1. Within the text of Standard CIP-005-4a, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator.

4.1.2 Balancing Authority.

4.1.3 Interchange Authority.

4.1.4 Transmission Service Provider.

4.1.5 Transmission Owner.

4.1.6 Transmission Operator.

4.1.7 Generator Owner.

4.1.8 Generator Operator.

4.1.9 Load Serving Entity.

4.1.10 NERC.

4.1.11 Regional Entity

4.2. The following are exempt from Standard CIP-005-4a:

4.2.1 Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 Responsible Entities that, in compliance with Standard CIP-002-4, identify that they have no Critical Cyber Assets.

4.2.4 In nuclear plants, the systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F. R. Section 73.54.

5. Effective Date: The first day of the eighth calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the ninth calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s).

R1.1. Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).

R1.2. For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.

R1.3. Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).

R1.4. Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005-4a.

R1.5. Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP-003-4; Standard CIP-004-4 Requirement R3; Standard CIP-005-4a Requirements R2 and R3; Standard CIP-006-4c Requirement R3; Standard CIP-007-4 Requirements R1 and R3 through R9; Standard CIP-008-4; and Standard CIP-009-4.

R1.6. The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), all electronic access points to the Electronic Security Perimeter(s) and the Cyber Assets deployed for the access control and monitoring of these access points.

R2. Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).

R2.1. These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.

R2.2. At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and shall document, individually or by specified grouping, the configuration of those ports and services.

R2.3. The Responsible Entity shall implement and maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).

R2.4. Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.

R2.5. The required documentation shall, at least, identify and describe:

R2.5.1. The processes for access request and authorization.

R2.5.2. The authentication methods.

R2.5.3. The review process for authorization rights, in accordance with Standard CIP-004-4 Requirement R4.

R2.5.4. The controls used to secure dial-up accessible connections.

R2.6. Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner. (Retired)

R3. Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.

R3.1. For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.

R3.2. Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.

R4. Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following:

R4.1. A document identifying the vulnerability assessment process;

R4.2. A review to verify that only ports and services required for operations at these access points are enabled;

R4.3. The discovery of all access points to the Electronic Security Perimeter;

R4.4. A review of controls for default accounts, passwords, and network management community strings;

R4.5. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.

R5. Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005-4a.

R5.1. The Responsible Entity shall ensure that all documentation required by Standard CIP-005-4a reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005-4a at least annually.

R5.2. The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.

R5.3. The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-4.

C. Measures

M1. The Responsible Entity shall make available documentation about the Electronic Security Perimeter as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation of the electronic access controls to the Electronic Security Perimeter(s), as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of controls implemented to log and monitor access to the Electronic Security Perimeter(s) as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation of its annual vulnerability assessment as specified in Requirement R4.

M5. The Responsible Entity shall make available access logs and documentation of review, changes, and log retention as specified in Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.2. The RE shall serve as the CEA with the following exceptions:

1.2.1 For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

1.2.1 For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2.1 For Responsible Entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2.2 For the ERO, a third-party monitor without vested interest in the outcome for the ERO shall serve as the Compliance Enforcement Authority.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep logs for a minimum of ninety calendar days, unless: a) longer retention is required pursuant to Standard CIP-008-4, Requirement R2; b) directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Responsible Entity shall keep other documents and records required by Standard CIP-005-4a from the previous full calendar year.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

2. Violation Severity Levels

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	MEDIUM	The Responsible Entity did not document one or more access points to the Electronic Security Perimeter(s).	The Responsible Entity identified but did not document one or more Electronic Security Perimeter(s).	The Responsible Entity did not ensure that one or more of the Critical Cyber Assets resides within an Electronic Security Perimeter. OR The Responsible Entity did not identify nor document one or more Electronic Security Perimeter(s).	The Responsible Entity did not ensure that one or more Critical Cyber Assets resides within an Electronic Security Perimeter, and the Responsible Entity did not identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s) for all Critical Cyber Assets.
R1.1.	MEDIUM	N/A	N/A	N/A	Access points to the Electronic Security Perimeter(s) do not include all externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).
R1.2.	MEDIUM	N/A	N/A	N/A	For one or more dial-up accessible Critical Cyber Assets that use a non-routable protocol, the Responsible Entity did not define an Electronic Security Perimeter for that single access point at the dial-up device.
R1.3.	MEDIUM	N/A	N/A	N/A	At least one end point of a communication link within the Electronic Security Perimeter(s) connecting discrete Electronic Security Perimeters was not considered an access point to the Electronic Security Perimeter.
R1.4.	MEDIUM	N/A	One or more non-critical Cyber Asset within a defined Electronic Security Perimeter is not identified but is protected pursuant to the requirements of Standard CIP-005.	One or more non-critical Cyber Asset within a defined Electronic Security Perimeter is identified but not protected pursuant to the requirements of Standard CIP-005.	One or more non-critical Cyber Asset within a defined Electronic Security Perimeter is not identified and is not protected pursuant to the requirements of Standard CIP-005.
R1.5.	MEDIUM	A Cyber Asset used in the access control and/or monitoring of the Electronic Security Perimeter(s) is provided with all but one (1) of the protective measures as specified in Standard CIP-003-4; Standard CIP-004-4 Requirement	A Cyber Asset used in the access control and/or monitoring of the Electronic Security Perimeter(s) is provided with all but two (2) of the protective measures as specified in Standard CIP-003-4; Standard CIP-004-4 Requirement R3; Standard CIP-005-4 Requirements R2 and R3;	A Cyber Asset used in the access control and/or monitoring of the Electronic Security Perimeter(s) is provided with all but three (3) of the protective measures as specified in Standard CIP-003-4; Standard CIP-004-4 Requirement R3; Standard CIP-005-4 Requirements R2 and R3; Standard CIP-006-4 Requirement R3; Standard CIP-007-4 Requirements R1 and R3 through R9; Standard CIP-008-4;	A Cyber Asset used in the access control and/or monitoring of the Electronic Security Perimeter(s) is provided without four (4) or more of the protective measures as specified in Standard CIP-003-4; Standard CIP-004-4 Requirement R3; Standard CIP-005-4 Requirements R2 and R3; Standard CIP-006-4 Requirement R3; Standard CIP-007-4 Requirements R1 and R3 through R9; Standard CIP-008-4;

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
		R3; Standard CIP-005-4 Requirements R2 and R3; Standard CIP-006-4 Requirement R3; Standard CIP-007-4 Requirements R1 and R3 through R9; Standard CIP-008-4; and Standard CIP-009-4.	Standard CIP-006-4 Requirement R3; Standard CIP-007-4 Requirements R1 and R3 through R9; Standard CIP-008-4; and Standard CIP-009-4.	and Standard CIP-009-4.	and Standard CIP-009-4.
R1.6.	LOWER	N/A	N/A	The Responsible Entity did not maintain documentation of one of the following: Electronic Security Perimeter(s), interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), electronic access point to the Electronic Security Perimeter(s) or Cyber Asset deployed for the access control and monitoring of these access points.	The Responsible Entity did not maintain documentation of two or more of the following: Electronic Security Perimeter(s), interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), electronic access points to the Electronic Security Perimeter(s) and Cyber Assets deployed for the access control and monitoring of these access points.
R2.	MEDIUM	N/A	The Responsible Entity implemented but did not document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).	The Responsible Entity documented but did not implement the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).	The Responsible Entity did not implement nor document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).
R2.1.	MEDIUM	N/A	N/A	N/A	The processes and mechanisms did not use an access control model that denies access by default, such that explicit access permissions must be specified.
R2.2.	MEDIUM	N/A	At one or more access points to the Electronic Security Perimeter(s), the Responsible Entity did not document, individually or by specified grouping, the configuration of those ports and services required for operation and for monitoring Cyber Assets within the Electronic Security	At one or more access points to the Electronic Security Perimeter(s), the Responsible Entity enabled ports and services not required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter but did document, individually or by specified grouping, the configuration of those ports and services.	At one or more access points to the Electronic Security Perimeter(s), the Responsible Entity enabled ports and services not required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and did not document, individually or by specified grouping, the configuration of those ports and services.

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Perimeter.		
R2.3.	MEDIUM	N/A	N/A	The Responsible Entity did implement but did not maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s) where applicable.	The Responsible Entity did not implement nor maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s) where applicable.
R2.4.	MEDIUM	N/A	N/A	N/A	Where external interactive access into the Electronic Security Perimeter has been enabled the Responsible Entity did not implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.
R2.5.	LOWER	The required documentation for R2 did not include one of the elements described in R2.5.1 through R2.5.4	The required documentation for R2 did not include two of the elements described in R2.5.1 through R2.5.4	The required documentation for R2 did not include three of the elements described in R2.5.1 through R2.5.4	The required documentation for R2 did not include any of the elements described in R2.5.1 through R2.5.4
R2.5.1.	LOWER	N/A	N/A	N/A	N/A
R2.5.2.	LOWER	N/A	N/A	N/A	N/A
R2.5.3.	LOWER	N/A	N/A	N/A	N/A
R2.5.4.	LOWER	N/A	N/A	N/A	N/A
R2.6. (Retired)	LOWER	The Responsible Entity did not maintain a document identifying the content of the banner. OR	Where technically feasible 5% but less than 10% of electronic access control devices did not display an appropriate use banner on the user screen upon all interactive access attempts.	Where technically feasible 10% but less than 15% of electronic access control devices did not display an appropriate use banner on the user screen upon all interactive access attempts.	Where technically feasible, 15% or more electronic access control devices did not display an appropriate use banner on the user screen upon all interactive access attempts.

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Where technically feasible less than 5% electronic access control devices did not display an appropriate use banner on the user screen upon all interactive access attempts.			
R3.	MEDIUM	The Responsible Entity did not document the electronic or manual processes for monitoring and logging access to access points. OR The Responsible Entity did not implement electronic or manual processes monitoring and logging at less than 5% of the access points.	The Responsible Entity did not implement electronic or manual processes monitoring and logging at 5% or more but less than 10% of the access points.	The Responsible Entity did not implement electronic or manual processes monitoring and logging at 10% or more but less than 15 % of the access points.	The Responsible Entity did not implement electronic or manual processes monitoring and logging at 15% or more of the access points.
R3.1.	MEDIUM	The Responsible Entity did not document the electronic or manual processes for monitoring access points to dial-up devices. OR Where technically feasible, the Responsible Entity did not implement electronic or manual processes for monitoring at less than 5% of the access points to dial-up devices.	Where technically feasible, the Responsible Entity did not implement electronic or manual processes for monitoring at 5% or more but less than 10% of the access points to dial-up devices.	Where technically feasible, the Responsible Entity did not implement electronic or manual processes for monitoring at 10% or more but less than 15% of the access points to dial-up devices.	Where technically feasible, the Responsible Entity did not implement electronic or manual processes for monitoring at 15% or more of the access points to dial-up devices.
R3.2.	MEDIUM	N/A	N/A	Where technically feasible, the Responsible Entity implemented security monitoring process(es) to detect and alert for attempts at or actual unauthorized accesses, however the alerts do not provide for appropriate	Where technically feasible, the Responsible Entity did not implement security monitoring process(es) to detect and alert for attempts at or actual unauthorized accesses. OR

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
				notification to designated response personnel.	Where alerting is not technically feasible, the Responsible Entity did not review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days
R4.	MEDIUM	The Responsible Entity did not perform a Vulnerability Assessment at least annually for less than 5% of access points to the Electronic Security Perimeter(s).	The Responsible Entity did not perform a Vulnerability Assessment at least annually for 5% or more but less than 10% of access points to the Electronic Security Perimeter(s).	The Responsible Entity did not perform a Vulnerability Assessment at least annually for 10% or more but less than 15% of access points to the Electronic Security Perimeter(s).	The Responsible Entity did not perform a Vulnerability Assessment at least annually for 15% or more of access points to the Electronic Security Perimeter(s). OR The vulnerability assessment did not include one (1) or more of the subrequirements R 4.1, R4.2, R4.3, R4.4, R4.5.
R4.1.	LOWER	N/A	N/A	N/A	N/A
R4.2.	MEDIUM	N/A	N/A	N/A	N/A
R4.3.	MEDIUM	N/A	N/A	N/A	N/A
R4.4.	MEDIUM	N/A	N/A	N/A	N/A
R4.5.	MEDIUM	N/A	N/A	N/A	N/A
R5.	LOWER	The Responsible Entity did not review, update, and maintain at least one but less than or equal to 5% of the documentation to support compliance with the requirements of Standard CIP-005-4.	The Responsible Entity did not review, update, and maintain greater than 5% but less than or equal to 10% of the documentation to support compliance with the requirements of Standard CIP-005-4.	The Responsible Entity did not review, update, and maintain greater than 10% but less than or equal to 15% of the documentation to support compliance with the requirements of Standard CIP-005-4.	The Responsible Entity did not review, update, and maintain greater than 15% of the documentation to support compliance with the requirements of Standard CIP-005-4.

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5.1.	LOWER	N/A	The Responsible Entity did not provide evidence of an annual review of the documents and procedures referenced in Standard CIP-005-4.	The Responsible Entity did not document current configurations and processes referenced in Standard CIP-005-4.	The Responsible Entity did not document current configurations and processes and did not review the documents and procedures referenced in Standard CIP-005-4 at least annually.
R5.2.	LOWER	For less than 5% of the applicable changes, the Responsible Entity did not update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	For 5% or more but less than 10% of the applicable changes, the Responsible Entity did not update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	For 10% or more but less than 15% of the applicable changes, the Responsible Entity did not update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	For 15% or more of the applicable changes, the Responsible Entity did not update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.
R5.3.	LOWER	The Responsible Entity retained electronic access logs for 75 or more calendar days, but for less than 90 calendar days.	The Responsible Entity retained electronic access logs for 60 or more calendar days, but for less than 75 calendar days.	The Responsible Entity retained electronic access logs for 45 or more calendar days , but for less than 60 calendar days.	The Responsible Entity retained electronic access logs for less than 45 calendar days.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	01/16/06	D.2.3.1 — Change "Critical Assets," to "Critical Cyber Assets" as intended.	03/24/06
2	Approved by NERC Board of Trustees 5/6/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Revised the wording of the Electronic Access Controls requirement stated in R2.3 to clarify that the Responsible Entity shall "implement and maintain" a procedure for securing dial-up access to the Electronic Security Perimeter(s). Changed compliance monitor to Compliance Enforcement Authority.	Revised.
3	12/16/09	Changed CIP-005-2 to CIP-005-3. Changed all references to CIP Version "2" standards to CIP Version "3" standards. For Violation Severity Levels, changed, "To be developed later" to "Developed separately."	Conforming revisions for FERC Order on CIP V2 Standards (9/30/2009)
2a	02/16/10	Added Appendix 1 — Interpretation of R1.3 approved by BOT on February 16, 2010	Addition
4a	01/24/11	Adopted by the NERC Board of Trustees	Update to conform to changes to CIP-002-4 (Project 2008-06) Update version number from "3" to "4a"
4a	4/19/12	FERC Order issued approving CIP-005-4a (approval becomes effective June 25, 2012) Added approved VRF/VSL table to section D.2.	
3a, 4a	TBD	R2.6 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

Appendix 1

Requirement Number and Text of Requirement
Section 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters. **Requirement R1.3** Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).
Question 1 (Section 4.2.2)
What kind of cyber assets are referenced in 4.2.2 as "associated"? What else could be meant except the devices forming the communication link?
Response to Question 1
In the context of applicability, associated Cyber Assets refer to any communications devices external to the Electronic Security Perimeter, i.e., beyond the point at which access to the Electronic Security Perimeter is controlled. Devices controlling access into the Electronic Security Perimeter are not exempt.
Question 2 (Section 4.2.2)
Is the communication link physical or logical? Where does it begin and terminate?
Response to Question 2
The drafting team interprets the data communication link to be physical or logical, and its termination points depend upon the design and architecture of the communication link.
Question 3 (Requirement R1.3)
Please clarify what is meant by an “endpoint”? Is it physical termination? Logical termination of OSI layer 2, layer 3, or above?
Response to Question 3
The drafting team interprets the endpoint to mean the device at which a physical or logical communication link terminates. The endpoint is the Electronic Security Perimeter access point if access into the Electronic Security Perimeter is controlled at the endpoint, irrespective of which Open Systems Interconnection (OSI) layer is managing the communication.
Question 4 (Requirement R1.3)
If “endpoint” is defined as logical and refers to layer 3 and above, please clarify if the termination points of an encrypted tunnel (layer 3) must be treated as an “access point? If two control centers are

owned and managed by the same entity, connected via an encrypted link by properly applied Federal Information Processing Standards, with tunnel termination points that are within the control center ESPs and PSPs and do not terminate on the firewall but on a separate internal device, and the encrypted traffic already passes through a firewall access point at each ESP boundary where port/protocol restrictions are applied, must these encrypted communication tunnel termination points be treated as "access points" in addition to the firewalls through which the encrypted traffic has already passed?
Response to Question 4
In the case where the “endpoint” is defined as logical and is >= layer 3, the termination points of an encrypted tunnel must be treated as an “access point.” The encrypted communication tunnel termination points referred to above are “access points.”

A. Introduction

1. Title: Cyber Security — Systems Security Management

2. Number: CIP-007-3

3. Purpose: Standard CIP-007-3 requires Responsible Entities to define methods, processes, and procedures for securing those systems determined to be Critical Cyber Assets, as well as the other (non-critical) Cyber Assets within the Electronic Security Perimeter(s). Standard CIP-007-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. Applicability:

4.1. Within the text of Standard CIP-007-3, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator.

4.1.2 Balancing Authority.

4.1.3 Interchange Authority.

4.1.4 Transmission Service Provider.

4.1.5 Transmission Owner.

4.1.6 Transmission Operator.

4.1.7 Generator Owner.

4.1.8 Generator Operator.

4.1.9 Load Serving Entity.

4.1.10 NERC.

4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-007-3:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007-3, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.

R1.1. The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.

R1.2. The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.

R1.3. The Responsible Entity shall document test results.

R2. Ports and Services — The Responsible Entity shall establish, document and implement a process to ensure that only those ports and services required for normal and emergency operations are enabled.

R2.1. The Responsible Entity shall enable only those ports and services required for normal and emergency operations.

R2.2. The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).

R2.3. In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.

R3. Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003-3 Requirement R6, shall establish, document and implement a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).

R3.1. The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the patches or upgrades.

R3.2. The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.

R4. Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software ("malware") prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic Security Perimeter(s).

R4.1. The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.

R4.2. The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention "signatures." The process must address testing and installing the signatures.

R5. Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.

R5.1. The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to know" with respect to work functions performed.

R5.1.1. The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-3 Requirement R5.

R5.1.2. The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.

R5.1.3. The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-3 Requirement R5 and Standard CIP-004-3 Requirement R4.

R5.2. The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.

R5.2.1. The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.

R5.2.2. The Responsible Entity shall identify those individuals with access to shared accounts.

R5.2.3. Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).

R5.3. At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:

R5.3.1. Each password shall be a minimum of six characters.

R5.3.2. Each password shall consist of a combination of alpha, numeric, and "special" characters.

R5.3.3. Each password shall be changed at least annually, or more frequently based on risk.

R6. Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible, implement automated tools or organizational process controls to monitor system events that are related to cyber security.

R6.1. The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.

R6.2. The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.

R6.3. The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008-3.

R6.4. The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.

R6.5. The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.

R7. Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-3.

R7.1. Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.

R7.2. Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.

R7.3. The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures. (Retired)

R8. Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:

R8.1. A document identifying the vulnerability assessment process;

R8.2. A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;

R8.3. A review of controls for default accounts; and,

R8.4. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.

R9. Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007-3 at least annually. Changes resulting from modifications to the systems or controls shall be documented within thirty calendar days of the change being completed.

C. Measures

M1. The Responsible Entity shall make available documentation of its security test procedures as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation and records of its security patch management program, as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation and records of its malicious software prevention program as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation and records of its account management program as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation and records of its security status monitoring program as specified in Requirement R6.

M7. The Responsible Entity shall make available documentation and records of its program for the disposal or redeployment of Cyber Assets as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation and records of its annual vulnerability assessment of all Cyber Assets within the Electronic Security Perimeters(s) as specified in Requirement R8.

M9. The Responsible Entity shall make available documentation and records demonstrating the review and update as specified in Requirement R9.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Responsible Entity shall retain security–related system event logs for ninety calendar days, unless longer retention is required pursuant to Standard CIP-008-3 Requirement R2.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment and acceptance of risk. Revised the Purpose of this standard to clarify that Standard CIP-007-2 requires Responsible Entities to define methods, processes, and procedures for securing Cyber Assets and other (non-Critical)	

		Assets within an Electronic Security Perimeter. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. R9 changed ninety (90) days to thirty (30) days Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version numbers from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	
3	TBD	R7.3 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

A. Introduction

1. Title: Cyber Security — Systems Security Management

2. Number: CIP-007-4

3. Purpose: Standard CIP-007-4 requires Responsible Entities to define methods, processes, and procedures for securing those systems determined to be Critical Cyber Assets, as well as the other (non-critical) Cyber Assets within the Electronic Security Perimeter(s). Standard CIP-007-4 should be read as part of a group of standards numbered Standards CIP-002-4 through CIP-009-4.

4. Applicability:

4.1. Within the text of Standard CIP-007-4, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator.

4.1.2 Balancing Authority.

4.1.3 Interchange Authority.

4.1.4 Transmission Service Provider.

4.1.5 Transmission Owner.

4.1.6 Transmission Operator.

4.1.7 Generator Owner.

4.1.8 Generator Operator.

4.1.9 Load Serving Entity.

4.1.10 NERC.

4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-007-4:

4.2.1 Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 In nuclear plants, the systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F. R. Section 73.54

4.2.4 Responsible Entities that, in compliance with Standard CIP-002-4, identify that they have no Critical Cyber Assets.

5. Effective Date: The first day of the eighth calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the ninth calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007-4, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.

R1.1. The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.

R1.2. The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.

R1.3. The Responsible Entity shall document test results.

R2. Ports and Services — The Responsible Entity shall establish, document and implement a process to ensure that only those ports and services required for normal and emergency operations are enabled.

R2.1. The Responsible Entity shall enable only those ports and services required for normal and emergency operations.

R2.2. The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).

R2.3. In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.

R3. Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003-4 Requirement R6, shall establish, document and implement a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).

R3.1. The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the patches or upgrades.

R3.2. The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.

R4. Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software ("malware") prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic Security Perimeter(s).

R4.1. The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.

R4.2. The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention "signatures." The process must address testing and installing the signatures.

R5. Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.

R5.1. The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to know" with respect to work functions performed.

R5.1.1. The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-4 Requirement R5.

R5.1.2. The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.

R5.1.3. The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-4 Requirement R5 and Standard CIP-004-4 Requirement R4.

R5.2. The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.

R5.2.1. The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.

R5.2.2. The Responsible Entity shall identify those individuals with access to shared accounts.

R5.2.3. Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).

R5.3. At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:

R5.3.1. Each password shall be a minimum of six characters.

R5.3.2. Each password shall consist of a combination of alpha, numeric, and "special" characters.

R5.3.3. Each password shall be changed at least annually, or more frequently based on risk.

R6. Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible, implement automated tools or organizational process controls to monitor system events that are related to cyber security.

R6.1. The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.

R6.2. The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.

R6.3. The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008-4.

R6.4. The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.

R6.5. The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.

R7. Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-4.

R7.1. Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.

R7.2. Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.

R7.3. The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures. (Retired)

R8. Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:

R8.1. A document identifying the vulnerability assessment process;

R8.2. A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;

R8.3. A review of controls for default accounts; and,

R8.4. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.

R9. Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007-4 at least annually. Changes resulting from modifications to the systems or controls shall be documented within thirty calendar days of the change being completed.

C. Measures

M1. The Responsible Entity shall make available documentation of its security test procedures as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation and records of its security patch management program, as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation and records of its malicious software prevention program as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation and records of its account management program as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation and records of its security status monitoring program as specified in Requirement R6.

M7. The Responsible Entity shall make available documentation and records of its program for the disposal or redeployment of Cyber Assets as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation and records of its annual vulnerability assessment of all Cyber Assets within the Electronic Security Perimeters(s) as specified in Requirement R8.

M9. The Responsible Entity shall make available documentation and records demonstrating the review and update as specified in Requirement R9.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.2. The RE shall serve as the CEA with the following exceptions:

1.2.1 For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

1.2.2 For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2.3 For Responsible Entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2.4 For the ERO, a third-party monitor without vested interest in the outcome for the ERO shall serve as the Compliance Enforcement Authority.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Responsible Entity shall retain security–related system event logs for ninety calendar days, unless longer retention is required pursuant to Standard CIP-008-4 Requirement R2.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information.

2. Violation Severity Levels

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	MEDIUM	N/A	The Responsible Entity did create, implement and maintain the test procedures as required in R1.1, **but did not document** that testing is performed as required in R1.2. OR The Responsible Entity did not document the test results as required in R1.3.	The Responsible Entity did not create, implement and maintain the test procedures as required in R1.1.	The Responsible Entity did not create, implement and maintain the test procedures as required in R1.1, AND The Responsible Entity did not document that testing was performed as required in R1.2 AND The Responsible Entity did not document the test results as required in R1.3.
R1.1.	MEDIUM	N/A	N/A	N/A	N/A
R1.2.	LOWER	N/A	N/A	N/A	N/A
R1.3.	LOWER	N/A	N/A	N/A	N/A
R2.	MEDIUM	N/A	The Responsible Entity established (implemented) but did not document a process to ensure that only those ports and services required for normal and emergency operations are enabled.	The Responsible Entity documented but did not establish (implement) a process to ensure that only those ports and services required for normal and emergency operations are enabled.	The Responsible Entity did not establish (implement) nor document a process to ensure that only those ports and services required for normal and emergency operations are enabled.
R2.1.	MEDIUM	The Responsible Entity enabled ports and services not required for normal and emergency operations on at least one but less than 5% of the Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity enabled ports and services not required for normal and emergency operations on 5% or more but less than 10% of the Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity enabled ports and services not required for normal and emergency operations on 10% or more but less than 15% of the Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity enabled ports and services not required for normal and emergency operations on 15% or more of the Cyber Assets inside the Electronic Security Perimeter(s).
R2.2.	MEDIUM	The Responsible Entity did not disable other ports and services, including those used for	The Responsible Entity did not disable other ports and services, including those used for testing purposes, prior to production use	The Responsible Entity did not disable other ports and services, including those used for testing purposes, prior to production use for 10% or more but less than 15% of the Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity did not disable other ports and services, including those used for testing purposes, prior to production use for 15% or more of the Cyber Assets inside the Electronic Security Perimeter(s).

		testing purposes, prior to production use for at least one but less than 5% of the Cyber Assets inside the Electronic Security Perimeter(s).	for 5% or more but less than 10% of the Cyber Assets inside the Electronic Security Perimeter(s).		
R2.3.	MEDIUM	N/A	N/A	N/A	For cases where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity did not document compensating measure(s) applied to mitigate risk exposure.
R3.	LOWER	The Responsible Entity established (implemented) and documented, either separately or as a component of the documented configuration management process specified in CIP-003-4 Requirement R6, a security patch management program **but** did not include one or more of the following: tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	The Responsible Entity established (implemented) but did not document, either separately or as a component of the documented configuration management process specified in CIP-003-4 Requirement R6, a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	The Responsible Entity documented but did not establish (implement), either separately or as a component of the documented configuration management process specified in CIP-003-4 Requirement R6, a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	The Responsible Entity did not establish (implement) nor document, either separately or as a component of the documented configuration management process specified in CIP-003-4 Requirement R6, a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).
R3.1.	LOWER	The Responsible Entity documented the assessment of security patches and security upgrades for applicability as required in Requirement R3 in more than 30 but less than 60 calendar days after the availability of the patches and upgrades.	The Responsible Entity documented the assessment of security patches and security upgrades for applicability as required in Requirement R3 in 60 or more but less than 90 calendar days after the availability of the patches and upgrades.	The Responsible Entity documented the assessment of security patches and security upgrades for applicability as required in Requirement R3 in 90 or more but less than 120 calendar days after the availability of the patches and upgrades.	The Responsible Entity documented the assessment of security patches and security upgrades for applicability as required in Requirement R3 in 120 calendar days or more after the availability of the patches and upgrades.

R3.2.	LOWER	N/A	N/A	N/A	The Responsible Entity did not document the implementation of applicable security patches as required in R3. OR Where an applicable patch was not installed, the Responsible Entity did not document the compensating measure(s) applied to mitigate risk exposure.
R4.	MEDIUM	The Responsible Entity, as technically feasible, did not use anti-virus software and other malicious software ("malware") prevention tools, nor implemented compensating measures, on at least one but less than 5% of Cyber Assets within the Electronic Security Perimeter(s).	The Responsible Entity, as technically feasible, did not use anti-virus software and other malicious software ("malware") prevention tools, nor implemented compensating measures, on at least 5% but less than 10% of Cyber Assets within the Electronic Security Perimeter(s).	The Responsible Entity, as technically feasible, did not use anti-virus software and other malicious software ("malware") prevention tools, nor implemented compensating measures, on at least 10% but less than 15% of Cyber Assets within the Electronic Security Perimeter(s).	The Responsible Entity, as technically feasible, did not use anti-virus software and other malicious software ("malware") prevention tools, nor implemented compensating measures, on 15% or more Cyber Assets within the Electronic Security Perimeter(s).
R4.1.	MEDIUM	N/A	N/A	N/A	The Responsible Entity did not document the implementation of antivirus and malware prevention tools for cyber assets within the electronic security perimeter. OR The Responsible Entity did not document the implementation of compensating measure(s) applied to mitigate risk exposure where antivirus and malware prevention tools are not installed.
R4.2.	MEDIUM	The Responsible Entity, as technically feasible, documented and implemented a process for the update of anti-virus and malware prevention "signatures.", but the process did not address testing and installation of the signatures.	The Responsible Entity, as technically feasible, did not document but implemented a process, including addressing testing and installing the signatures, for the update of anti-virus and malware prevention "signatures."	The Responsible Entity, as technically feasible, documented but did not implement a process, including addressing testing and installing the signatures, for the update of anti-virus and malware prevention "signatures."	The Responsible Entity, as technically feasible, did not document nor implement a process including addressing testing and installing the signatures for the update of anti-virus and malware prevention "signatures."
R5.	LOWER	N/A	The Responsible Entity implemented but did not document technical and procedural controls that enforce access authentication of, and accountability for, all user activity.	The Responsible Entity documented but did not implement technical and procedural controls that enforce access authentication of, and accountability for, all user activity.	The Responsible Entity did not document nor implement technical and procedural controls that enforce access authentication of, and accountability for, all user activity.

R5.1.	MEDIUM	N/A	N/A	N/A	The Responsible Entity did not ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to know" with respect to work functions performed.
R5.1.1.	LOWER	At least one user account but less than 1% of user accounts implemented by the Responsible Entity, were not approved by designated personnel.	One (1) % or more of user accounts but less than 3% of user accounts implemented by the Responsible Entity were not approved by designated personnel.	Three (3) % or more of user accounts but less than 5% of user accounts implemented by the Responsible Entity were not approved by designated personnel.	Five (5) % or more of user accounts implemented by the Responsible Entity were not approved by designated personnel.
R5.1.2.	LOWER	N/A	The Responsible Entity generated logs with sufficient detail to create historical audit trails of individual user account access activity, however the logs do not contain activity for a minimum of 90 days.	The Responsible Entity generated logs with insufficient detail to create historical audit trails of individual user account access activity.	The Responsible Entity did not generate logs of individual user account access activity.
R5.1.3.	MEDIUM	N/A	N/A	N/A	The Responsible Entity did not review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-4 Requirement R5 and Standard CIP-004-4 Requirement R4.
R5.2.	LOWER	N/A	N/A	N/A	The Responsible Entity did not implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.
R5.2.1.	MEDIUM	N/A	N/A	The Responsible Entity's policy did not include the removal, disabling, or renaming of such accounts where possible, however for accounts that must remain enabled, passwords were changed prior to putting any system into service.	For accounts that must remain enabled, the Responsible Entity did not change passwords prior to putting any system into service.
R5.2.2.	LOWER	N/A	N/A	N/A	The Responsible Entity did not identify all individuals with access to shared accounts.
R5.2.3.	MEDIUM	N/A	Where such accounts must be shared, the Responsible Entity has a policy for managing the use of such accounts, but is missing 1 of the following 3 items: a) limits access to only those with authorization, b) has an audit trail of the account use (automated or	Where such accounts must be shared, the Responsible Entity has a policy for managing the use of such accounts, but is missing 2 of the following 3 items: a) limits access to only those with authorization, b) has an audit trail of the account use (automated or manual), c) has specified steps for securing the account in the event of personnel changes (for example, change in assignment or termination).	Where such accounts must be shared, the Responsible Entity does not have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).

			manual), c) has specified steps for securing the account in the event of personnel changes (for example, change in assignment or termination).		
R5.3.	LOWER	The Responsible Entity requires and uses passwords as technically feasible, but only addresses 2 of the requirements in R5.3.1, R5.3.2., R5.3.3.	The Responsible Entity requires and uses passwords as technically feasible but only addresses 1 of the requirements in R5.3.1, R5.3.2., R5.3.3.	The Responsible Entity requires but does not use passwords as required in R5.3.1, R5.3.2., R5.3.3 and did not demonstrate why it is not technically feasible.	The Responsible Entity does not require nor use passwords as required in R5.3.1, R5.3.2., R5.3.3 and did not demonstrate why it is not technically feasible.
R5.3.1.	LOWER	N/A	N/A	N/A	N/A
R5.3.2.	LOWER	N/A	N/A	N/A	N/A
R5.3.3.	MEDIUM	N/A	N/A	N/A	N/A
R6.	LOWER	The Responsible Entity, as technically feasible, did not implement automated tools or organizational process controls to monitor system events that are related to cyber security for at least one but less than 5% of Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity, as technically feasible, did not implement automated tools or organizational process controls to monitor system events that are related to cyber security for 5% or more but less than 10% of Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity did not implement automated tools or organizational process controls, as technically feasible, to monitor system events that are related to cyber security for 10% or more but less than 15% of Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity did not implement automated tools or organizational process controls, as technically feasible, to monitor system events that are related to cyber security for 15% or more of Cyber Assets inside the Electronic Security Perimeter(s).
R6.1.	MEDIUM	N/A	The Responsible Entity implemented but did not document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity documented but did not implement the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity did not implement nor document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.

R6.2.	MEDIUM	N/A	N/A	N/A	The Responsible entity's security monitoring controls do not issue automated or manual alerts for detected Cyber Security Incidents.
R6.3.	MEDIUM	N/A	N/A	N/A	The Responsible Entity did not maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008-4.
R6.4.	LOWER	The Responsible Entity retained the logs specified in Requirement R6, for at least 60 days, but less than 90 days.	The Responsible Entity retained the logs specified in Requirement R6, for at least 30 days, but less than 60 days.	The Responsible Entity retained the logs specified in Requirement R6, for at least one day, but less than 30 days.	The Responsible Entity did not retain any logs specified in Requirement R6.
R6.5.	LOWER	N/A	N/A	N/A	The Responsible Entity did not review logs of system events related to cyber security nor maintain records documenting review of logs.
R7.	LOWER	The Responsible Entity established and implemented formal methods, processes, and procedures for disposal and redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP- 005-4 **but** did not maintain records as specified in R7.3. (Retired)	The Responsible Entity established and implemented formal methods, processes, and procedures for disposal of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-4 **but** did not address redeployment as specified in R7.2.	The Responsible Entity established and implemented formal methods, processes, and procedures for redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-4 **but** did not address disposal as specified in R7.1.	The Responsible Entity did not establish or implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-4.
R7.1.	LOWER	N/A	N/A	N/A	N/A
R7.2.	LOWER	N/A	N/A	N/A	N/A
R7.3. (Retired)	LOWER	N/A	N/A	N/A	N/A

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R8	LOWER	The Responsible Entity performed at least annually a Vulnerability Assessment that included 95% or more but less than 100% of Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity performed at least annually a Vulnerability Assessment that included 90% or more but less than 95% of Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity performed at least annually a Vulnerability Assessment that included more than 85% but less than 90% of Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity performed at least annually a Vulnerability Assessment for 85% or less of Cyber Assets within the Electronic Security Perimeter. OR The vulnerability assessment did not include one (1) or more of the subrequirements 8.1, 8.2, 8.3, 8.4.
R8.1.	LOWER	N/A	N/A	N/A	N/A
R8.2.	MEDIUM	N/A	N/A	N/A	N/A
R8.3.	MEDIUM	N/A	N/A	N/A	N/A
R8.4.	MEDIUM	N/A	N/A	N/A	N/A
R9	LOWER	N/A	N/A	The Responsible Entity did not review and update the documentation specified in Standard CIP-007-4 at least annually. OR The Responsible Entity did not document changes resulting from modifications to the systems or controls within thirty calendar days of the change being completed.	The Responsible Entity did not review and update the documentation specified in Standard CIP-007-4 at least annually **nor** were changes resulting from modifications to the systems or controls documented within thirty calendar days of the change being completed.

E. **Regional Variances**

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment and acceptance of risk. Revised the Purpose of this standard to clarify that Standard CIP-007-2 requires Responsible Entities to define methods, processes, and procedures for securing Cyber Assets and other (non-Critical) Assets within an Electronic Security Perimeter. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. R9 changed ninety (90) days to thirty (30) days Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version numbers from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	
4	Board approved 01/24/2011	Update version number from “3” to “4”	Update to conform to changes to CIP-002-4 (Project 2008-06)
4	4/19/12	FERC Order issued approving CIP-007-4 (approval becomes effective June 25, 2012) Added approved VRF/VSL table to section D.2.	
3, 4	TBD	R7.3 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

A. Introduction

1. Title: **Disturbance Reporting**

2. Number: EOP-004-1

3. Purpose: Disturbances or unusual occurrences that jeopardize the operation of the Bulk Electric System, or result in system equipment damage or customer interruptions, need to be studied and understood to minimize the likelihood of similar events in the future.

4. Applicability

4.1. Reliability Coordinators.

4.2. Balancing Authorities.

4.3. Transmission Operators.

4.4. Generator Operators.

4.5. Load Serving Entities.

4.6. Regional Reliability Organizations.

5. Effective Date: January 1, 2007

B. Requirements

R1. Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports. (Retired)

R2. A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities.

R3. A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.

R3.1. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized.

R3.2. Applicable reporting forms are provided in Attachments 1-EOP-004 and 2-EOP-004.

R3.3. Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall promptly notify its Regional Reliability Organization(s) and NERC, and verbally provide as much information as is available at that

time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.

R3.4. If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.

R4. When a Bulk Electric System disturbance occurs, the Regional Reliability Organization shall make its representatives on the NERC Operating Committee and Disturbance Analysis Working Group available to the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity immediately affected by the disturbance for the purpose of providing any needed assistance in the investigation and to assist in the preparation of a final report.

R5. The Regional Reliability Organization shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if Regional Reliability Organization tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Reliability Organization shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Reliability Organization has taken to accelerate implementation.

C. Measures

M1. The Regional Reliability Organization shall have and provide upon request as evidence, its current regional reporting procedure that is used to facilitate preparation of preliminary and final disturbance reports. (Requirement 1) (Retired)

M2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity that has a reportable incident shall have and provide upon request evidence that could include, but is not limited to, the preliminary report, computer printouts, operator logs, or other equivalent evidence that will be used to confirm that it prepared and delivered the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports to NERC within 24 hours of its recognition as specified in Requirement 3.1.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and/or Load Serving Entity that has a reportable incident shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it provided information verbally as time permitted, when system conditions precluded the preparation of a report in 24 hours. (Requirement 3.3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC shall be responsible for compliance monitoring of the Regional Reliability Organizations.

Regional Reliability Organizations shall be responsible for compliance monitoring of Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Load-serving Entities.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Regional Reliability Organization shall have its current, in-force, regional reporting procedure as evidence of compliance. (Measure 1) (Retired)

Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and/or Load Serving Entity that is either involved in a Bulk Electric System disturbance or has a reportable incident shall keep data related to the incident for a year from the event or for the duration of any regional investigation, whichever is longer. (Measures 2 through 4)

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

See Attachments:

- EOP-004 Disturbance Reporting Form
- Table 1 EOP-004

2. Levels of Non-Compliance for a Regional Reliability Organization

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: No current procedure to facilitate preparation of preliminary and final disturbance reports as specified in R1. (Retired)

3. Levels of Non-Compliance for a Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load- Serving Entity:

3.1. Level 1: There shall be a level one non-compliance if any of the following conditions exist:

3.1.1 Failed to prepare and deliver the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports to NERC within 24 hours of its recognition as specified in Requirement 3.1

3.1.2 Failed to provide disturbance information verbally as time permitted, when system conditions precluded the preparation of a report in 24 hours as specified in R3.3

3.1.3 Failed to prepare a final report within 60 days as specified in R3.4

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable

3.4. Level 4: Not applicable.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	May 23, 2005	Fixed reference to attachments 1-EOP-004-0 and 2-EOP-004-0, Changed chart title 1-FAC-004-0 to 1-EOP-004-0, Fixed title of Table 1 to read 1-EOP-004-0, and fixed font.	Errata
0	July 6, 2005	Fixed email in Attachment 1-EOP-004-0 from info@nerc.com to esisac@nerc.com.	Errata

0	July 26, 2005	Fixed Header on page 8 to read EOP-004-0	Errata
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	TBD	R1 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

Attachment 1-EOP-004
NERC Disturbance Report Form

Introduction

These disturbance reporting requirements apply to all Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Load Serving Entities, and provide a common basis for all NERC disturbance reporting. The entity on whose system a reportable disturbance occurs shall notify NERC and its Regional Reliability Organization of the disturbance using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. Reports can be sent to NERC via email (esisac@nerc.com) by facsimile (609-452-9550) using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. If a disturbance is to be reported to the U.S. Department of Energy also, the responding entity may use the DOE reporting form when reporting to NERC. Note: All Emergency Incident and Disturbance Reports (Schedules 1 and 2) sent to DOE shall be simultaneously sent to NERC, preferably electronically at esisac@nerc.com.

The NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports are to be made for any of the following events:

1. The loss of a bulk power transmission component that significantly affects the integrity of interconnected system operations. Generally, a disturbance report will be required if the event results in actions such as:
   a. Modification of operating procedures.
   b. Modification of equipment (e.g. control systems or special protection systems) to prevent reoccurrence of the event.
   c. Identification of valuable lessons learned.
   d. Identification of non-compliance with NERC standards or policies.
   e. Identification of a disturbance that is beyond recognized criteria, i.e. three-phase fault with breaker failure, etc.
   f. Frequency or voltage going below the under-frequency or under-voltage load shed points.
2. The occurrence of an interconnected system separation or system islanding or both.
3. Loss of generation by a Generator Operator, Balancing Authority, or Load-Serving Entity — 2,000 MW or more in the Eastern Interconnection or Western Interconnection and 1,000 MW or more in the ERCOT Interconnection.
4. Equipment failures/system operational actions which result in the loss of firm system demands for more than 15 minutes, as described below:
   a. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
   b. All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50% of the total customers being supplied immediately prior to the incident, whichever is less.
5. Firm load shedding of 100 MW or more to maintain the continuity of the bulk electric system.

6. Any action taken by a Generator Operator, Transmission Operator, Balancing Authority, or Load-Serving Entity that results in:
   a. Sustained voltage excursions equal to or greater than ±10%, or
   b. Major damage to power system components, or
   c. Failure, degradation, or misoperation of system protection, special protection schemes, remedial action schemes, or other operating systems that do not require operator intervention, which did result in, or could have resulted in, a system disturbance as defined by steps 1 through 5 above.
7. An Interconnection Reliability Operating Limit (IROL) violation as required in reliability standard TOP-007.
8. Any event that the Operating Committee requests to be submitted to Disturbance Analysis Working Group (DAWG) for review because of the nature of the disturbance and the insight and lessons the electricity supply and delivery industry could learn.

NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report

☐ Check here if this is an Interconnection Reliability Operating Limit (IROL) violation report.

1.	Organization filing report.		
2.	Name of person filing report.		
3.	Telephone number.		
4.	Date and time of disturbance. Date:(mm/dd/yy) Time/Zone:		
5.	Did the disturbance originate in your system?	Yes ☐ No ☐	
6.	Describe disturbance including: cause, equipment damage, critical services interrupted, system separation, key scheduled and actual flows prior to disturbance and in the case of a disturbance involving a special protection or remedial action scheme, what action is being taken to prevent recurrence.		
7.	Generation tripped. MW Total List generation tripped		
8.	Frequency. Just prior to disturbance (Hz): Immediately after disturbance (Hz max.): Immediately after disturbance (Hz min.):		
9.	List transmission lines tripped (specify voltage level of each line).		
10.		FIRM	INTERRUPTIBLE
	Demand tripped (MW):		
	Number of affected Customers:		

	Demand lost (MW-Minutes):		
11.	Restoration time.	INITIAL	FINAL
	Transmission:		
	Generation:		
	Demand:		

Attachment 2-EOP-004
U.S. Department of Energy Disturbance Reporting Requirements

Introduction

The U.S. Department of Energy (DOE), under its relevant authorities, has established mandatory reporting requirements for electric emergency incidents and disturbances in the United States. DOE collects this information from the electric power industry on Form EIA-417 to meet its overall national security and Federal Energy Management Agency's Federal Response Plan (FRP) responsibilities. DOE will use the data from this form to obtain current information regarding emergency situations on U.S. electric energy supply systems. DOE's Energy Information Administration (EIA) will use the data for reporting on electric power emergency incidents and disturbances in monthly EIA reports. In addition, the data may be used to develop legislative recommendations, reports to the Congress and as a basis for DOE investigations following severe, prolonged, or repeated electric power reliability problems.

Every Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity must use this form to submit mandatory reports of electric power system incidents or disturbances to the DOE Operations Center, which operates on a 24-hour basis, seven days a week. All other entities operating electric systems have filing responsibilities to provide information to the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity when necessary for their reporting obligations and to file form EIA-417 in cases where these entities will not be involved. EIA requests that it be notified of those that plan to file jointly and of those electric entities that want to file separately.

Special reporting provisions exist for those electric utilities located within the United States, but for whom Reliability Coordinator oversight responsibilities are handled by electrical systems located across an international border. A foreign utility handling U.S. Balancing Authority responsibilities, may wish to file this information voluntarily to the DOE. Any U.S.-based utility in this international situation needs to inform DOE that these filings will come from a foreign-based electric system or file the required reports themselves.

Form EIA-417 must be submitted to the DOE Operations Center if any one of the following applies (see Table 1-EOP-004-0 — Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies):

1. Uncontrolled loss of 300 MW or more of firm system load for more than 15 minutes from a single incident.
2. Load shedding of 100 MW or more implemented under emergency operational policy.
3. System-wide voltage reductions of 3 percent or more.
4. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system.
5. Actual or suspected physical attacks that could impact electric power system adequacy or reliability; or vandalism, which target components of any security system. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.

6. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.
7. Fuel supply emergencies that could impact electric power system adequacy or reliability.
8. Loss of electric service to more than 50,000 customers for one hour or more.
9. Complete operational failure or shut-down of the transmission and/or distribution electrical system.

The initial DOE Emergency Incident and Disturbance Report (form EIA-417 – Schedule 1) shall be submitted to the DOE Operations Center within 60 minutes of the time of the system disruption. Complete information may not be available at the time of the disruption. However, provide as much information as is known or suspected at the time of the initial filing. If the incident is having a critical impact on operations, a telephone notification to the DOE Operations Center (202-586-8100) is acceptable, pending submission of the completed form EIA-417. Electronic submission via an on-line web-based form is the preferred method of notification. However, electronic submission by facsimile or email is acceptable.

An updated form EIA-417 (Schedule 1 and 2) is due within 48 hours of the event to provide complete disruption information. Electronic submission via facsimile or email is the preferred method of notification. Detailed DOE Incident and Disturbance reporting requirements can be found at: ftp://ftp.eia.doe.gov/pub/electricity/eiafor417.doc.

Table 1-EOP-004-0 Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies				
Incident No.	**Incident**	**Threshold**	**Report Required**	**Time**
1	Uncontrolled loss of Firm System Load	≥ 300 MW – 15 minutes or more	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
2	Load Shedding	≥ 100 MW under emergency operational policy	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
3	Voltage Reductions	3% or more – applied system-wide	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
4	Public Appeals	Emergency conditions to reduce demand	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
5	Physical sabotage, terrorism or vandalism	On physical security systems – suspected or real	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
6	Cyber sabotage, terrorism or vandalism	If the attempt is believed to have or did happen	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
7	Fuel supply emergencies	Fuel inventory or hydro storage levels ≤ 50% of normal	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
8	Loss of electric service	≥ 50,000 for 1 hour or more	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
9	Complete operation failure of electrical system	If isolated or interconnected electrical systems suffer total electrical system collapse	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
All DOE EIA-417 Schedule 1 reports are to be filed within 60-minutes after the start of an incident or disturbance All DOE EIA-417 Schedule 2 reports are to be filed within 48-hours after the start of an incident or disturbance				

All entities required to file a DOE EIA-417 report (Schedule 1 & 2) shall send a copy of these reports to NERC simultaneously, but no later than 24 hours after the start of the incident or disturbance.				
Incident No.	**Incident**	**Threshold**	**Report Required**	**Time**
1	Loss of major system component	Significantly affects integrity of interconnected system operations	NERC Prelim Final report	24 hour 60 day
2	Interconnected system separation or system islanding	Total system shutdown Partial shutdown, separation, or islanding	NERC Prelim Final report	24 hour 60 day
3	Loss of generation	≥ 2,000 – Eastern Interconnection ≥ 2,000 – Western Interconnection ≥ 1,000 – ERCOT Interconnection	NERC Prelim Final report	24 hour 60 day
4	Loss of firm load ≥15-minutes	Entities with peak demand ≥3,000: loss ≥300 MW All others ≥200MW or 50% of total demand	NERC Prelim Final report	24 hour 60 day
5	Firm load shedding	≥100 MW to maintain continuity of bulk system	NERC Prelim Final report	24 hour 60 day
6	System operation or operation actions resulting in:	• Voltage excursions ≥10% • Major damage to system components • Failure, degradation, or misoperation of SPS	NERC Prelim Final report	24 hour 60 day
7	IROL violation	Reliability standard TOP-007.	NERC Prelim Final report	72 hour 60 day
8	As requested by ORS Chairman	Due to nature of disturbance & usefulness to industry (lessons learned)	NERC Prelim Final report	24 hour 60 day
All NERC Operating Security Limit and Preliminary Disturbance reports will be filed within 24 hours after the start of the incident. If an entity must file a DOE EIA-417 report on an incident, which requires a NERC Preliminary report, the Entity may use the DOE EIA-417 form for both DOE and NERC reports.				
Any entity reporting a DOE or NERC incident or disturbance has the responsibility to also notify its Regional Reliability Organization.				

A. Introduction

1. Title: **System Restoration from Blackstart Resources**

2. Number: EOP-005-2

3. Purpose: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to assure reliability is maintained during restoration and priority is placed on restoring the Interconnection.

4. Applicability:

4.1. Transmission Operators.

4.2. Generator Operators.

4.3. Transmission Owners identified in the Transmission Operators restoration plan.

4.4. Distribution Providers identified in the Transmission Operators restoration plan.

5. Proposed Effective Date: Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Time Horizon = Operations Planning]*

R1.1. Strategies for system restoration that are coordinated with the Reliability Coordinator's high level strategy for restoring the Interconnection.

R1.2. A description of how all Agreements or mutually agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.

R1.3. Procedures for restoring interconnections with other Transmission Operators under the direction of the Reliability Coordinator.

R1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

R1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.

R1.6. Identification of acceptable operating voltage and frequency limits during restoration.

R1.7. Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection.

R1.8. Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.

R1.9. Operating Processes for transferring authority back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.

R2. Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. *[Time Horizon = Operations Planning]*

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually agreed predetermined schedule. *[Time Horizon = Operations Planning]*

R3.1. If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary. (Retired)

R4. Each Transmission Operator shall update its restoration plan within 90 calendar days after identifying any unplanned permanent System modifications, or prior to implementing a planned BES modification, that would change the implementation of its restoration plan. *[Time Horizon = Operations Planning]*

R4.1. Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval within the same 90 calendar day period.

R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its implementation date. *[Time Horizon = Operations Planning]*

R6. Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify: *[Time Horizon = Long-term Planning]*

R6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

R6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.

R6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

R7. Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each

affected Transmission Operator shall implement its restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. *[Time Horizon = Real-time Operations]*

R8. Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator. *[Time Horizon = Real-time Operations]*

R9. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include: *[Time Horizon = Operations Planning]*

R9.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.

R9.2. A list of required tests including:

R9.2.1. The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.

R9.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.

R9.3. The minimum duration of each of the required tests.

R10. Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program shall include training on the following: *[Time Horizon = Operations Planning]*

R10.1. System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan.

R10.2. Restoration priorities.

R10.3. Building of cranking paths.

R10.4. Synchronizing (re-energized sections of the System).

R11. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Time Horizon = Operations Planning]*

R12. Each Transmission Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Time Horizon = Operations Planning]*

R13. Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements. *[Time Horizon = Operations Planning]*

R14. Each Generator Operator with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus. *[Time Horizon = Operations Planning]*

R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. *[Time Horizon = Operations Planning]*

R16. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Time Horizon = Operations Planning]*

R16.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R9.

R16.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

R17. Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following: *[Time Horizon = Operations Planning]*

R17.1. System restoration plan including coordination with the Transmission Operator.

R17.2. The procedures documented in Requirement R14.

R18. Each Generator Operator shall participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. *[Time Horizon = Operations Planning]*

C. Measures

M1. Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator.

M2. Each Transmission Operator shall have evidence such as e-mails with receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan in accordance with Requirement R2.

M3. Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, e-mails with receipts, or registered mail receipts, that it has annually reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.

M4. Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, e-mails with receipts, or registered mail receipts, that it has updated its restoration plan and submitted it to its Reliability Coordinator in accordance with Requirement R4.

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan available in its primary and backup control rooms and its System Operators prior to its implementation date in accordance with Requirement R5.

M6. Each Transmission Operator shall have documentation such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with Requirement R6.

M7. If there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service, each Transmission Operator involved shall have evidence such as voice recordings, e-mail, dated computer printouts, or operator logs, that it implemented its restoration plan or restoration plan strategies in accordance with Requirement R7.

M8. If there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service, each Transmission Operator involved in such an event shall have evidence, such as voice recordings, e-mail, dated computer printouts, or operator logs, that it resynchronized shut down areas in accordance with Requirement R8.

M9. Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement R9.

M10. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R10.

M11. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R11.

M12. Each Transmission Operator shall have evidence, such as training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R12.

M13. Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R13.

M14. Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R14.

M15. Each Generator Operator with a Blackstart Resource shall provide evidence, such as e-mails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within twenty-four hours of such changes in accordance with Requirement R15.

M16. Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R16.

M17. Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R17.

M18. Each Generator Operator shall have evidence, such as dated training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R18.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Approved restoration plan and any restoration plans in force since the last compliance audit for Requirement R1, Measure M1.
- Provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- Submission of the Transmission Operator's annually reviewed restoration plan to its Reliability Coordinator for the current calendar year and three prior calendar years for Requirement R3, Measure M3.
- Submission of an updated restoration plan to its Reliability Coordinator for all versions for the current calendar year and the prior three years for Requirement R4, Measure M4.
- The current, restoration plan approved by the Reliability Coordinator and any restoration plans for the last three calendar years that was made available in its control rooms for Requirement R5, Measure M5.
- The verification results for the current, approved restoration plan and the previous approved restoration plan for Requirement R6, Measure M6.
- Implementation of its restoration plan or restoration plan strategies on any occasion for three calendar years if there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service for Requirement R7, Measure M7.
- Resynchronization of shut down areas on any occasion over three calendar years if there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service for Requirement R8, Measure M8.
- The verification process and results for the current Blackstart Resource testing requirements and the last previous Blackstart Resource testing requirements for Requirement R9, Measure M9.
- Actual training program materials or descriptions for three calendar years for Requirement R10, Measure M10.
- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit as well as one previous compliance audit period for Requirement R12, Measure M12.

If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Transmission Operator, applicable Transmission Owner, and applicable Distribution provider shall keep data or evidence to show compliance as identified

below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Actual training program materials or descriptions and actual training records for three calendar years for Requirement R11, Measure M11.

If a Transmission Operator, applicable Transmission owner, or applicable Distribution Provider is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Transmission Operator and Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current Blackstart Resource Agreements and any Blackstart Resource Agreements or mutually agreed upon procedures or protocols in force since its last compliance audit for Requirement R13, Measure M13.

The Generator Operator with a Blackstart Resource shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Current documentation and any documentation in force since its last compliance audit on procedures to start each Blackstart Resources and for energizing a bus for Requirement R14, Measure M14.
- Notification to its Transmission Operator of any known changes to its Blackstart Resource capabilities over the last three calendar years for Requirement R15, Measure M15.
- The verification test results for the current set of requirements and one previous set for its Blackstart Resources for Requirement R16, Measure M16.
- Actual training program materials and actual training records for three calendar years for Requirement R17, Measure M17.

If a Generation Operator with a Blackstart Resource is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Generator Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit for Requirement R18, Measure M18.

If a Generation Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	May 2, 2007	Approved by Board of Trustees	Revised
2	TBD	Revisions pursuant to Project 2006-03	Updated testing requirements Incorporated Attachment 1 into the requirements Updated Measures and Compliance to match new Requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-005-2 (approval effective 5/23/11)	
2	TBD	R3.1 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

A. Introduction

1. Title: Coordination of Plans For New Generation, Transmission, and End-User Facilities

2. Number: FAC-002-1

3. Purpose: To avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements.

4. Applicability:

4.1. Generator Owner

4.2. Transmission Owner

4.3. Distribution Provider

4.4. Load-Serving Entity

4.5. Transmission Planner

4.6. Planning Authority

5. (Proposed) Effective Date: The first day of the first calendar quarter six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.

B. Requirements

R1. The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:

1.1. Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.

1.2. Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.

1.3. Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.

1.4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under both normal and contingency conditions in accordance with Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.

1.5. Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.

R2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected

transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) and NERC on request (within 30 calendar days). (Retired)

C. Measures

M1. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider's documentation of its assessment of the reliability impacts of new facilities shall address all items in Reliability Standard FAC-002-0_R1.

M2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each have evidence of its assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems is retained and provided to other entities in accordance with Reliability Standard FAC-002-0_R2. (Retired)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits
Self-Certifications
Spot Checking
Compliance Violation Investigations
Self-Reporting

Complaints

1.4. Data Retention

Evidence of the assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems: Three years.

1.5. Additional Compliance Information

None

2. Violation Severity Levels (no changes)

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	January 13, 2006	Removed duplication of "Regional Reliability Organizations(s).	Errata
1	TBD	Modified to address Order No. 693 Directives contained in paragraph 693.	Revised.

1	TBD	R2 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

A. Introduction

1. Title: **Facility Ratings Methodology**

2. Number: FAC-008-1

3. Purpose: To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. Applicability

4.1. Transmission Owner

4.2. Generator Owner

5. Effective Date: August 7, 2006

B. Requirements

R1. The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities. The methodology shall include all of the following:

R1.1. A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

R1.2. The method by which the Rating (of major BES equipment that comprises a Facility) is determined.

R1.2.1. The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

R1.2.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

R1.3. Consideration of the following:

R1.3.1. Ratings provided by equipment manufacturers.

R1.3.2. Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).

R1.3.3. Ambient conditions.

R1.3.4. Operating limitations.

R1.3.5. Other assumptions.

R2. The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request. (Retired)

R3. If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the

Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why. (Retired)

C. Measures

M1. The Transmission Owner and Generator Owner shall each have a documented Facility Ratings Methodology that includes all of the items identified in FAC-008 Requirement 1.1 through FAC-008 Requirement 1.3.5.

M2. The Transmission Owner and Generator Owner shall each have evidence it made its Facility Ratings Methodology available for inspection within 15 business days of a request as follows: (Retired)

M2.1 The Reliability Coordinator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Reliability Coordinator Area. (Retired)

M2.2 The Transmission Operator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its portion of the Reliability Coordinator Area. (Retired)

M2.3 The Transmission Planner shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Transmission Planning Area. (Retired)

M2.4 The Planning Authority shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Planning Authority Area. (Retired)

M3. If the Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides documented comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall have evidence that it provided a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why. (Retired)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Transmission Owner and Generator Owner shall self-certify its compliance to the Compliance Monitor at least once every three years. New Transmission Owners and Generator Owners shall each demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each keep all superseded portions of its Facility Ratings Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on the Facility Ratings Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall each make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Facility Ratings Methodology

1.4.2 Superseded portions of its Facility Ratings Methodology that had been replaced, changed or revised within the past 12 months

1.4.3 Documented comments provided by a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Authority on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings methodology, and the associated responses

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if any of the following conditions exists:

2.1.1 The Facility Ratings Methodology does not contain a statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

2.1.2 The Facility Ratings Methodology does not address one of the required equipment types identified in FAC-008 R1.2.1.

2.1.3 No evidence of responses to a Reliability Coordinator's, Transmission Operator, Transmission Planner, or Planning Authority's comments on the Facility Ratings Methodology. (Retired)

2.2. Level 2: The Facility Ratings Methodology is missing the assumptions used to determine Facility Ratings or does not address two of the required equipment types identified in FAC-008 R1.2.1.

2.3. Level 3: The Facility Ratings Methodology does not address three of the required equipment types identified in FAC-008-1 R1.2.1.

2.4. Level 4: The Facility Ratings Methodology does not address both Normal and Emergency Ratings ~~or the Facility Ratings Methodology was not made available for inspection within 15 business days of receipt of a request~~. (Deleted text retired)

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E. **Regional Differences**

None Identified.

Version History

Version	Date	Action	Change Tracking
1	01/01/05	1. Lower cased the word "draft" and "drafting team" where appropriate. 2. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 3. Changed "Timeframe" to "Time	01/20/05

		Frame" and "twelve" to "12" in item D, 1.2.	
1	TBD	R2 and R3 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

A. Introduction

1. **Title:** **Facility Ratings**

2. **Number:** FAC-008-3

3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Generator Owner.

5. **Effective Date:** The first day of the first calendar quarter that is twelve months beyond the date approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the first day of the first calendar quarter twelve months following BOT adoption.

B. Requirements

R1. Each Generator Owner shall have documentation for determining the Facility Ratings of its solely and jointly owned generator Facility(ies) up to the low side terminals of the main step up transformer if the Generator Owner does not own the main step up transformer and the high side terminals of the main step up transformer if the Generator Owner owns the main step up transformer. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The documentation shall contain assumptions used to rate the generator and at least one of the following:

- Design or construction information such as design criteria, ratings provided by equipment manufacturers, equipment drawings and/or specifications, engineering analyses, method(s) consistent with industry standards (e.g. ANSI and IEEE), or an established engineering practice that has been verified by testing or engineering analysis.
- Operational information such as commissioning test results, performance testing or historical performance records, any of which may be supplemented by engineering analyses.

1.2. The documentation shall be consistent with the principle that the Facility Ratings do not exceed the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

R2. Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of interconnection with the Transmission Owner that contains all of the following. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. The methodology used to establish the Ratings of the equipment that comprises the Facility(ies) shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.

- One or more industry standards developed through an open process such as Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.

2.2. The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R2, Part 2.1 including identification of how each of the following were considered:

2.2.1. Equipment Rating standard(s) used in development of this methodology.

2.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

2.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).

2.2.4. Operating limitations.[1]

2.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

2.4. The process by which the Rating of equipment that comprises a Facility is determined.

2.4.1. The scope of equipment addressed shall include, but not be limited to, conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

2.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

R3. Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The methodology used to establish the Ratings of the equipment that comprises the Facility shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronics Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.

3.2. The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R3, Part 3.1 including identification of how each of the following were considered:

3.2.1. Equipment Rating standard(s) used in development of this methodology.

[1] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

3.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

3.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).

3.2.4. Operating limitations.[2]

3.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

3.4. The process by which the Rating of equipment that comprises a Facility is determined.

3.4.1. The scope of equipment addressed shall include, but not be limited to, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

3.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

R4. Each Transmission Owner shall make its Facility Ratings methodology and each Generator Owner shall each make its documentation for determining its Facility Ratings and its Facility Ratings methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners and Planning Coordinators that have responsibility for the area in which the associated Facilities are located, within 21 calendar days of receipt of a request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]* (Retired)

R5. If a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Coordinator provides documented comments on its technical review of a Transmission Owner's Facility Ratings methodology or Generator Owner's documentation for determining its Facility Ratings and its Facility Rating methodology, the Transmission Owner or Generator Owner shall provide a response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings methodology and, if no change will be made to that Facility Ratings methodology, the reason why. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]* (Retired)

R6. Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R7. Each Generator Owner shall provide Facility Ratings (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) as scheduled by such requesting entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R8. Each Transmission Owner (and each Generator Owner subject to Requirement R2) shall provide requested information as specified below (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s): *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

[2] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

8.1. As scheduled by the requesting entities:

8.1.1. Facility Ratings

8.1.2. Identity of the most limiting equipment of the Facilities

8.2. Within 30 calendar days (or a later date if specified by the requester), for any requested Facility with a Thermal Rating that limits the use of Facilities under the requester's authority by causing any of the following: 1) An Interconnection Reliability Operating Limit, 2) A limitation of Total Transfer Capability, 3) An impediment to generator deliverability, or 4) An impediment to service to a major load center:

8.2.1. Identity of the existing next most limiting equipment of the Facility

8.2.2. The Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1.

C. Measures

M1. Each Generator Owner shall have documentation that shows how its Facility Ratings were determined as identified in Requirement 1.

M2. Each Generator Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 2, Parts 2.1 through 2.4.

M3. Each Transmission Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 3, Parts 3.1 through 3.4.

M4. Each Transmission Owner shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it made its Facility Ratings methodology available for inspection within 21 calendar days of a request in accordance with Requirement 4. The Generator Owner shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it made its documentation for determining its Facility Ratings or its Facility Ratings methodology available for inspection within 21 calendar days of a request in accordance with Requirement R4. (Retired)

M5. If the Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Coordinator provides documented comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings methodology or a Generator Owner's documentation for determining its Facility Ratings, the Transmission Owner or Generator Owner shall have evidence, (such as a copy of a dated electronic or hard copy note, or other comparable evidence from the Transmission Owner or Generator Owner addressed to the commenter that includes the response to the comment,) that it provided a response to that commenting entity in accordance with Requirement R5. (Retired)

M6. Each Transmission Owner and Generator Owner shall have evidence to show that its Facility Ratings are consistent with the documentation for determining its Facility Ratings as specified in Requirement R1 or consistent with its Facility Ratings methodology as specified in Requirements R2 and R3 (Requirement R6).

M7. Each Generator Owner shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it provided its Facility Ratings to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) in accordance with Requirement R7.

M8. Each Transmission Owner (and Generator Owner subject to Requirement R2) shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it provided its Facility Ratings and identity of limiting equipment to its associated Reliability

Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. **Compliance Enforcement Authority**

Regional Entity

1.2. **Compliance Monitoring and Enforcement Processes:**

- Self-Certifications
- Spot Checking
- Compliance Audits
- Self-Reporting
- Compliance Violation Investigations
- Complaints

1.3. **Data Retention**

The Generator Owner shall keep its current documentation (for R1) and any modifications to the documentation that were in force since last compliance audit period for Measure M1 and Measure M6.

The Generator Owner shall keep its current, in force Facility Ratings methodology (for R2) and any modifications to the methodology that were in force since last compliance audit period for Measure M2 and Measure M6.

The Transmission Owner shall keep its current, in force Facility Ratings methodology (for R3) and any modifications to the methodology that were in force since the last compliance audit for Measure M3 and Measure M6.

The Transmission Owner and Generator Owner shall keep its current, in force Facility Ratings and any changes to those ratings for three calendar years for Measure M6.

The Generator Owner and Transmission Owner shall each keep evidence for Measure M4, and Measure M5, for three calendar years. (Retired)

The Generator Owner shall keep evidence for Measure M7 for three calendar years.

The Transmission Owner (and Generator Owner that is subject to Requirement R2) shall keep evidence for Measure M8 for three calendar years.

If a Generator Owner or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit and all subsequent compliance records.

1.4. **Additional Compliance Information**

None

Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	• The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.1.	The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.2.	The Generator Owner failed to provide documentation for determining its Facility Ratings.
R2	The Generator Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R2: • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R2: • 2.1 • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner's Facility Rating methodology did not address all the components of Requirement R2, Part 2.4. OR The Generator Owner failed to include in its Facility Rating Methodology, three of the following Parts of Requirement R2: • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner's Facility Rating methodology failed to recognize a facility's rating based on the most limiting component rating as required in Requirement R2, Part 2.3 OR The Generator Owner failed to include in its Facility Rating Methodology four or more of the following Parts of Requirement R2: • 2.1 • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4
R3	The Transmission Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R3: • 3.1 • 3.2.1	The Transmission Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R3: • 3.1 • 3.2.1	The Transmission Owner's Facility Rating methodology did not address either of the following Parts of Requirement R3: • 3.4.1 • 3.4.2	The Transmission Owner's Facility Rating methodology failed to recognize a Facility's rating based on the most limiting component rating as required in Requirement R3, Part 3.3 OR

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	• 3.2.2 • 3.2.3 • 3.2.4	• 3.2.2 • 3.2.3 • 3.2.4	OR The Transmission Owner failed to include in its Facility Rating methodology three of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner failed to include in its Facility Rating methodology four or more of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4
R4 (Retired)	The responsible entity made its Facility Ratings methodology or Facility Ratings documentation available within more than 21 calendar days but less than or equal to 31 calendar days after a request.	The responsible entity made its Facility Ratings methodology or Facility Ratings documentation available within more than 31 calendar days but less than or equal to 41 calendar days after a request.	The responsible entity made its Facility Rating methodology or Facility Ratings documentation available within more than 41 calendar days but less than or equal to 51 calendar days after a request.	The responsible entity failed to make its Facility Ratings methodology or Facility Ratings documentation available in more than 51 calendar days after a request. (R3)
R5 (Retired)	The responsible entity provided a response in more than 45 calendar days but less than or equal to 60 calendar days after a request. (R5)	The responsible entity provided a response in more than 60 calendar days but less than or equal to 70 calendar days after a request. OR The responsible entity provided a response within 45 calendar days, and the response indicated that a change will not be made to the Facility Ratings methodology or Facility Ratings documentation but did not indicate why no change will be made. (R5)	The responsible entity provided a response in more than 70 calendar days but less than or equal to 80 calendar days after a request. OR The responsible entity provided a response within 45 calendar days, but the response did not indicate whether a change will be made to the Facility Ratings methodology or Facility Ratings documentation. (R5)	The responsible entity failed to provide a response as required in more than 80 calendar days after the comments were received. (R5)

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for 5% or less of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 5% or more, but less than up to (and including) 10% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 10% up to (and including) 15% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than15% of its solely owned and jointly owned Facilities. (R6)
R7	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to and including 15 calendar days.	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 15 calendar days but less than or equal to 25 calendar days.	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 25 calendar days but less than or equal to 35 calendar days.	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 35 calendar days. OR The Generator Owner failed to provide its Facility Ratings to the requesting entities.
R8	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to and including 15 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 100%, but not less than or equal to 95% of the required Rating information to all of the requesting entities. (R8, Part 8.1)	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 15 calendar days but less than or equal to 25 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 95%, but not less than or equal to 90% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 25 calendar days but less than or equal to 35 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 90%, but not less than or equal to 85% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 35 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 85% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR The responsible entity provided the required Rating information to the requesting entity, but did so more

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	OR The responsible entity provided the required Rating information to the requesting entity, but the information was provided up to and including 15 calendar days late. (R8, Part 8.2) OR The responsible entity provided less than 100%, but not less than or equal to 95% of the required Rating information to the requesting entity. (R8, Part 8.2)	The responsible entity provided the required Rating information to the requesting entity, but did so more 15 calendar days but less than or equal to 25 calendar days late. (R8, Part 8.2) OR The responsible entity provided less than 95%, but not less than or equal to 90% of the required Rating information to the requesting entity. (R8, Part 8.2)	The responsible entity provided the required Rating information to the requesting entity, but did so more than 25 calendar days but less than or equal to 35 calendar days late. (R8, Part 8.2) OR The responsible entity provided less than 90%, but no less than or equal to 85% of the required Rating information to the requesting entity. (R8, Part 8.2)	than 35 calendar days late. (R8, Part 8.2) OR The responsible entity provided less than 85 % of the required Rating information to the requesting entity. (R8, Part 8.2) OR The responsible entity failed to provide its Rating information to the requesting entity. (R8, Part 8.1)

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E. **Regional Variances**

None.

F. **Associated Documents**

Version History

Version	Date	Action	Change Tracking
1	Feb 7, 2006	Approved by Board of Trustees	New
1	Mar 16, 2007	Approved by FERC	New
2	May 12, 2010	Approved by Board of Trustees	Complete Revision, merging FAC_008-1 and FAC-009-1 under Project 2009-06 and address directives from Order 693
3	May 24, 2011	Addition of Requirement R8	Project 2009-06 Expansion to address third directive from Order 693
3	May 24, 2011	Adopted by NERC Board of Trustees	
3	November 17, 2011	FERC Order issued approving FAC-008-3	
3	May 17, 2012	FERC Order issued directing the VRF for Requirement R2 be changed from “Lower” to “Medium”	
3	TBD	R4 and R5 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

Standard FAC-010-2.1 — System Operating Limits Methodology for the Planning Horizon

A. Introduction

1. Title: **System Operating Limits Methodology for the Planning Horizon**

2. Number: FAC-010-2.1

3. Purpose: To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. Applicability

4.1. Planning Authority

5. Effective Date: April 19, 2010

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retired)

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retired)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years~~. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired)

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The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses. (Retired)

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology. (Retired)

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance following single and multiple contingencies, but does not address the pre-contingency state (R2.1)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following multiple contingencies, but does not meet the performance for response to single contingencies. (R2.2 –R2.4)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state but does not require that SOLs be set to meet the BES performance specified for response to single contingencies (R2.2-R2.4) and does not require that SOLs be set to meet the BES performance specified for response to multiple contingencies. (R2.5-R2.6)
R3	The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes	One of the following: The Planning Authority issued its SOL Methodology and changes	One of the following: The Planning Authority issued its SOL Methodology and changes	One of the following: The Planning Authority failed to issue its SOL Methodology and

Requirement	Lower	Moderate	High	Severe
	to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but

Requirement	Lower	Moderate	High	Severe
				four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5 (Retired)	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Planning Authority received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. **Regional Differences**

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word "each" from the 1st sentence of section D.1.3, Data Retention.	01/11/07
2	June 24, 2008	Adopted by Board of Trustees; FERC Order 705	Revised
2		Changed the effective date to July 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2.1	November 5, 2009	Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.	Errata
2.1	April 19, 2010	FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.	Errata
2.1	TBD	R5 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

A. Introduction

1. Title: **System Operating Limits Methodology for the Operations Horizon**

2. Number: FAC-011-2

3. Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. Applicability

4.1. Reliability Coordinator

5. Effective Date: April 29, 2009

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

[1] The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retired)

C. **Measures**

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5 (Retired)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years~~. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired)

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The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses. (Retired)

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology (Retired)

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of three or more of the following: R3.1 through R3.7.
R4	One or both of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Reliability Coordinator issued its SOL Methodology and

Requirement	Lower	Moderate	High	Severe
	provided up to 30 calendar days after the effectiveness of the change.	calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to

Requirement	Lower	Moderate	High	Severe
				30 calendar days after the effectiveness of the change.
R5 (Retired)	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	TBD	R5 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

A. Introduction

1. Title: Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon

2. Number: FAC-013-2

3. Purpose: To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.

4. Applicability:

4.1. Planning Coordinators

5. Effective Date:

In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

B. Requirements

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. A statement that the assessment shall respect known System Operating Limits (SOLs).

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

R2. Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each functional entity that has a reliability-related need for the Transfer Capability methodology and submits a request for that methodology within 30 calendar days of receiving that written request.

R3. If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why. *[Violation Risk Factor: Lower][Time Horizon: Long-term Planning]* (Retired)

R4. During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

C. Measures

M1. Each Planning Coordinator shall have a Transfer Capability methodology that includes the information specified in Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability methodology in accordance with Requirement R2

M3. Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3. (Retired)

M4. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5.

M6. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available in accordance with Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

The Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall have its current Transfer Capability methodology and any prior versions of the Transfer Capability methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment. (R3 retired)
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate two of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator did not have a Transfer Capability methodology. OR The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate three or more of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.

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R2	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 90 calendar days but not more than 120 calendar days after receipt of a request.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 120 calendar days after receipt of a request.
R3 **(Retired)**	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.	The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability methodology.

R4.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.

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R5	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5,, but not more than 60 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability methodology under the requirements of R5.
R6	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to provide the requested data as required in Requirement R6.

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E. **Regional Variances**

None.

F. **Associated Documents**

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Lower cased the word "draft" and "drafting team" where appropriate. 3. Changed Anticipated Action #5, page 1, from "30-day" to "Thirty-day." 4. Added or removed "periods."	01/20/05
2	01/24/11	Approved by BOT	
2	11/17/11	FERC Order issued approving FAC-013-2	
2	5/17/12	FERC Order issued directing the VRF's for Requirements R1. and R4. be changed from "Lower" to "Medium." FERC Order issued correcting the High and Severe VSL language for R1.	
2	TBD	R3 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

A. Introduction

1. Title: **Interchange Confirmation**

2. Number: **INT-007-1**

3. Purpose: To ensure that each Arranged Interchange is checked for reliability before it is implemented.

4. Applicability

4.1. Interchange Authority.

5. Effective Date: January 1, 2007

B. Requirements

R1. The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following:

R1.1. Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate).

R1.2. All reliability entities involved in the Arranged Interchange are currently in the NERC registry. (Retired)

R1.3. The following are defined:

R1.3.1. Generation source and load sink.

R1.3.2. Megawatt profile.

R1.3.3. Ramp start and stop times.

R1.3.4. Interchange duration.

R1.4. Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall show evidence that it has verified the Arranged Interchange information prior to the dissemination of the Confirmed Interchange.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be twelve months from the last noncompliance to Requirement 1.

1.3. Data Retention

The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. Complaints will be evaluated by the Compliance Monitor.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate an Interchange Authority's verification that all Arranged Interchange was balanced and valid as defined in R1. The Compliance Monitor may request up to a three-month period of historical data ending with the date the request is received by the Interchange Authority.

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate an Interchange Authority's verification that an Arranged Interchange was balanced and valid as defined in R1 for that specific Interchange

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] where Interchange-related data was not verified as defined in R1.

2.2. Level 2: Two occurrences where Interchange-related data was not verified as defined in R1.

2.3. Level 3: Three occurrences where Interchange-related data was not verified as defined in R1.

2.4. Level 4: Four or more occurrences where Interchange-related data was not verified as defined in R1.

E. Regional Differences

None

[1] This does not include instances of not verifying due to extenuating circumstances approved by the Compliance Monitor.

Version History

Version	Date	Action	Change Tracking
1	TBD	R1.2 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

A. Introduction

1. Title: **Coordination of Real-time Activities Between Reliability Coordinators**

2. Number: **IRO-016-1**

3. Purpose: To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

4. Applicability

4.1. Reliability Coordinator

5. Effective Date: November 1, 2006

B. Requirements

R1. The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.

R1.1. If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken.

R1.2. If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.).

R1.2.1. If time permits, this re-evaluation shall be done before taking corrective actions.

R1.2.2. If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved.

R1.3. If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.

R2. The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both. (Retired)

C. Measures

M1. For each event that requires Reliability Coordinator-to-Reliability Coordinator coordination, each involved Reliability Coordinator shall have evidence (operator logs or other data sources) of the actions taken for either the event or for the disagreement on the problem or for both.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The performance reset period shall be one calendar year.

1.3. Data Retention

The Reliability Coordinator shall keep auditable evidence for a rolling 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until it has been found compliant. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance, whichever is longer.

1.4. Additional Compliance Information

The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall use a scheduled on-site review at least once every three years. The Compliance Monitor shall conduct an investigation upon a complaint that is received within 30 days of an alleged infraction's discovery date. The Compliance Monitor shall complete the investigation and report back to all involved Reliability Coordinators (the Reliability Coordinator that complained as well as the Reliability Coordinator that was investigated) within 45 days after the start of the investigation. As part of an audit or investigation, the Compliance Monitor shall interview other Reliability Coordinators within the Interconnection and verify that the Reliability Coordinator being audited or investigated has been coordinating actions to prevent or resolve potential, expected, or actual problems that adversely impact the Interconnection.

The Reliability Coordinator shall have the following available for its Compliance Monitor to inspect during a scheduled, on-site review or within five working days of a request as part of an investigation upon complaint:

1.4.1 Evidence (operator log or other data source) to show coordination with other Reliability Coordinators.

2. Levels of Non-Compliance

2.1. Level 1: For potential, actual or expected events which required Reliability Coordinator-to-Reliability Coordinator coordination, the Reliability Coordinator did coordinate, but did not have evidence that it coordinated with other Reliability Coordinators.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: For potential, actual or expected events which required Reliability Coordinator-to-Reliability Coordinator coordination, the Reliability Coordinator did not coordinate with other Reliability Coordinators.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
Version 1	August 10, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Hyphenated "30-day" and "Reliability Coordinator-to-Reliability Coordinator" when used as adjective.	01/20/06

		3. Changed standard header to be consistent with standard "Title." 4. Added "periods" to items where appropriate. 5. Initial capped heading "Definitions of Terms Used in Standard." 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all words that are not "defined" terms — drafting team, and self-certification. 8. Changed apostrophes to "smart" symbols. 9. Removed comma after word "condition" in item R.1.1. 10. Added comma after word "expected" in item 1.4, last sentence. 11. Removed extra spaces between words where appropriate.	
1	TBD	R2 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

A. Introduction

1. Title: **Nuclear Plant Interface Coordination**

2. Number: NUC-001-2

3. Purpose: This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.

4. Applicability:

4.1. Nuclear Plant Generator Operator.

4.2. Transmission Entities shall mean all entities that are responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs). Such entities may include one or more of the following:

4.2.1 Transmission Operators.

4.2.2 Transmission Owners.

4.2.3 Transmission Planners.

4.2.4 Transmission Service Providers.

4.2.5 Balancing Authorities.

4.2.6 Reliability Coordinators.

4.2.7 Planning Coordinators.

4.2.8 Distribution Providers.

4.2.9 Load-serving Entities.

4.2.10 Generator Owners.

4.2.11 Generator Operators.

5. Effective Date: April 1, 2010

B. Requirements

R1. The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt [*Risk Factor: Lower*]

R2. The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements[1] that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs. [*Risk Factor: Medium*]

R3. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. [*Risk Factor: Medium*]

R4. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall: [*Risk Factor: High*]

1. Agreements may include mutually agreed upon procedures or protocols in effect between entities or between departments of a vertically integrated system.

R4.1. Incorporate the NPIRs into their operating analyses of the electric system.

R4.2. Operate the electric system to meet the NPIRs.

R4.3. Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.

R5. The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard. [*Risk Factor: High*]

R6. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs. [*Risk Factor: Medium*]

R7. Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]

R8. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]

R9. The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2: [*Risk Factor: Medium*]

R9.1. Administrative elements: (Retired)

R9.1.1. Definitions of key terms used in the agreement. (Retired)

R9.1.2. Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs. (Retired)

R9.1.3. A requirement to review the agreement(s) at least every three years. (Retired)

R9.1.4. A dispute resolution mechanism. (Retired)

R9.2. Technical requirements and analysis:

R9.2.1. Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.

R9.2.2. Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.

R9.2.3. Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.

R9.3. Operations and maintenance coordination:

R9.3.1. Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control coordination and maintenance of these facilities.

R9.3.2. Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.

R9.3.3. Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.

R9.3.4. Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.

R9.3.5. Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power. .

R9.3.6. Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity's plan.

R9.3.7. Coordination of the NPIRs with transmission system Special Protection Systems and underfrequency and undervoltage load shedding programs.

R9.4. Communications and training:

R9.4.1. Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time requirements, and definitions of terms.

R9.4.2. Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.

R9.4.3. Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.

R9.4.4. Provisions for supplying information necessary to report to government agencies, as related to NPIRs.

R9.4.5. Provisions for personnel training, as related to NPIRs.

C. Measures

M1. The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide a copy of the transmittal and receipt of transmittal of the proposed NPIRs to the responsible Transmission Entities. (Requirement 1)

M2. The Nuclear Plant Generator Operator and each Transmission Entity shall each have a copy of the Agreement(s) addressing the elements in Requirement 9 available for inspection upon request of the Compliance Enforcement Authority. (Requirement 2 and 9)

M3. Each Transmission Entity responsible for planning analyses in accordance with the Agreement shall, upon request of the Compliance Enforcement Authority, provide a copy of the planning analyses results transmitted to the Nuclear Plant Generator Operator, showing incorporation of the NPIRs. The Compliance Enforcement Authority shall refer to the Agreements developed in accordance with this standard for specific requirements. (Requirement 3)

M4. Each Transmission Entity responsible for operating the electric system in accordance with the Agreement shall demonstrate or provide evidence of the following, upon request of the Compliance Enforcement Authority:

M4.1 The NPIRs have been incorporated into the current operating analysis of the electric system. (Requirement 4.1)

M4.2 The electric system was operated to meet the NPIRs. (Requirement 4.2)

M4.3 The Transmission Entity informed the Nuclear Plant Generator Operator when it became aware it lost the capability to assess the operation of the electric system affecting the NPIRs. (Requirement 4.3)

M5. The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, demonstrate or provide evidence that the Nuclear Power Plant is being operated consistent with the Agreements developed in accordance with this standard. (Requirement 5)

M6. The Transmission Entities and Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide evidence of the coordination between the Transmission Entities and the Nuclear Plant Generator Operator regarding outages and maintenance activities which affect the NPIRs. (Requirement 6)

M7. The Nuclear Plant Generator Operator shall provide evidence that it informed the applicable Transmission Entities of changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that would impact the ability of the Transmission Entities to meet the NPIRs. (Requirement 7)

M8. The Transmission Entities shall each provide evidence that it informed the Nuclear Plant Generator Operator of changes to electric system design, configuration, operations, limits, protection systems, or capabilities that would impact the ability of the Nuclear Plant Generator Operator to meet the NPIRs. (Requirement 8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- For Measure 1, the Nuclear Plant Generator Operator shall keep its latest transmittals and receipts.
- For Measure 2, the Nuclear Plant Generator Operator and each Transmission Entity shall have its current, in-force agreement.
- For Measure 3, the Transmission Entity shall have the latest planning analysis results.
- For Measures 4.3, 6 and 8, the Transmission Entity shall keep evidence for two years plus current.
- For Measures 5, 6 and 7, the Nuclear Plant Generator Operator shall keep evidence for two years plus current.

If a Responsible Entity is found non-compliant it shall keep information related to the noncompliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

2.1. Lower: Agreement(s) exist per this standard and NPIRs were identified and implemented, but documentation described in M1-M8 was not provided.

2.2. Moderate: Agreement(s) exist per R2 and NPIRs were identified and implemented, but one or more elements of the Agreement in R9 were not met.

2.3. High: One or more requirements of R3 through R8 were not met.

2.4. Severe: No proposed NPIRs were submitted per R1, no Agreement exists per this standard, or the Agreements were not implemented.

E. Regional Differences

The design basis for Canadian (CANDU) NPPs does not result in the same licensing requirements as U.S. NPPs. NRC design criteria specifies that in addition to emergency on-site electrical power, electrical power from the electric network also be provided to permit safe shutdown. This requirement is specified in such NRC Regulations as 10 CFR 50 Appendix A — General Design Criterion 17 and 10 CFR 50.63 Loss of all alternating current power. There are no equivalent Canadian Regulatory requirements for Station Blackout (SBO) or coping times as they do not form part of the licensing basis for CANDU NPPs.
Therefore the definition of NPLR for Canadian CANDU units will be as follows:

Nuclear Plant Licensing Requirements (NPLR) are requirements included in the design basis of the nuclear plant and are statutorily mandated for the operation of the plant; when used in this standard, NPLR shall mean nuclear power plant licensing requirements for avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	May 2, 2007	Approved by Board of Trustees	New
2	To be determined	Modifications for Order 716 to Requirement R9.3.5 and footnote 1; modifications to bring compliance elements into conformance with the latest version of the ERO Rules of Procedure.	Revision
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	January 22, 2010	Approved by FERC on January 21, 2010 Added Effective Date	Update
2	TBD	R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

A. Introduction

1. Title: **Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program.**

2. Number: PRC-010-0

3. Purpose: Provide System preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding (UVLS) program.

4. Applicability:

4.1. Load-Serving Entity that operates a UVLS program

4.2. Transmission Owner that owns a UVLS program

4.3. Transmission Operator that operates a UVLS program

4.4. Distribution Provider that owns or operates a UVLS program

5. Effective Date: April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall periodically (at least every five years or as required by changes in system conditions) conduct and document an assessment of the effectiveness of the UVLS program. This assessment shall be conducted with the associated Transmission Planner(s) and Planning Authority(ies).

R1.1. This assessment shall include, but is not limited to:

R1.1.1. Coordination of the UVLS programs with other protection and control systems in the Region and with other Regional Reliability Organizations, as appropriate.

R1.1.2. Simulations that demonstrate that the UVLS programs performance is consistent with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0.

R1.1.3. A review of the voltage set points and timing.

R2. The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days). (Retired)

C. Measures

M1. Each Transmission Owner's and Distribution Provider's UVLS program shall include the elements identified in Reliability Standard PRC-010-0_R1.

M2. Each Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall have evidence it provided documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC as specified in Reliability Standard PRC-010-0_R2. (Retired)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

Assessments every five years or as required by System changes.

Current assessment on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: An assessment of the UVLS program did not address one of the three requirements listed in Reliability Standard PRC-010-0_R1.1 or an assessment of the UVLS program was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	TBD	R2 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

Standard PRC-022-1 — Under-Voltage Load Shedding Program Performance

A. Introduction

1. **Title:** **Under-Voltage Load Shedding Program Performance**

2. **Number:** **PRC-022-1**

3. **Purpose:** Ensure that Under Voltage Load Shedding (UVLS) programs perform as intended to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).

4. **Applicability**

   4.1. Transmission Operator that operates a UVLS program.

   4.2. Distribution Provider that operates a UVLS program.

   4.3. Load-Serving Entity that operates a UVLS program.

5. **Effective Date:** May 1, 2006

B. Requirements

R1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall analyze and document all UVLS operations and Misoperations. The analysis shall include:

R1.1. A description of the event including initiating conditions.

R1.2. A review of the UVLS set points and tripping times.

R1.3. A simulation of the event, if deemed appropriate by the Regional Reliability Organization. For most events, analysis of sequence of events may be sufficient and dynamic simulations may not be needed.

R1.4. A summary of the findings.

R1.5. For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature.

R2. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90 calendar days of a request. (Retired)

C. Measures

M1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall have documentation of its analysis of UVLS operations and Misoperations in accordance with Requirement 1.1 through 1.5.

M2. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall have evidence that it provided documentation of its analysis of UVLS program performance within 90 calendar days of a request by the Regional Reliability Organization. (Retired)

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall retain documentation of its analyses of UVLS operations and Misoperations for two years. The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

Transmission Operator, Load-Serving Entity, and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Documentation of the analysis of UVLS performance was provided but did not include one of the five requirements in R1.

2.3. Level 3: Documentation of the analysis of UVLS performance was provided but did not include two or more of the five requirements in R1.

2.4. Level 4: Documentation of the analysis of UVLS performance was not provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	December 1, 2005	1. Removed comma after 2004 in "Development Steps Completed," #1. 2. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 3. Lower cased the word "region," "board," and "regional" throughout document where appropriate. 4. Added or removed "periods" where appropriate. 5. Changed "Timeframe" to "Time Frame" in item D, 1.2.	January 20, 2006
1	TBD	R2 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

A. Introduction

1. **Title:** **Voltage and Reactive Control**

2. **Number:** VAR-001-2

3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Purchasing-Selling Entities.

   4.3. Load Serving Entities.

5. **(Proposed) Effective Date:** The first day of the first calendar quarter six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.

B. Requirements

R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

R2. Each Transmission Operator shall acquire sufficient reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load – within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R3. The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.

R3.1. Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.

R3.2. For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule [1] at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).

R5. Each Purchasing-Selling Entity and Load Serving Entity shall arrange for (self-provide or purchase) reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load– to satisfy its reactive requirements identified by its Transmission Service Provider. (Retired)

[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

R6. The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.

R6.1. When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.

R7. The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.

R9. Each Transmission Operator shall maintain reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load– to support its voltage under first Contingency conditions.

R9.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R10. Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

R11. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

M1. The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires to follow such a schedule.

M2. The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.

M3. The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.

M4. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with Requirement 11.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Operator shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	TBD	Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised.
2	TBD	R5 and associated elements retired as part of the Paragraph 81 project (Project 2013-02)	

Complete Violation Severity Levels Matrix

Encompassing All Commission-Approved Reliability Standards

September 21, 2012

Change History Table is located at the end of the document

Complete Violation Severity Level Matrix (BAL)
Encompassing All Commission-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
BAL-001-0.1a	R1.	Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee. ***See Standard for Formula.***	The Balancing Authority Area's value of CPS1 is less than 100% but greater than or equal to 95%.	The Balancing Authority Area's value of CPS1 is less than 95% but greater than or equal to 90%.	The Balancing Authority Area's value of CPS1 is less than 90% but greater than or equal to 85%.	The Balancing Authority Area's value of CPS1 is less than 85%.
BAL-001-0.1a	R2.	Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}. ***See Standard for Formula.***	The Balancing Authority Area's value of CPS2 is less than 90% but greater than or equal to 85%.	The Balancing Authority Area's value of CPS2 is less than 85% but greater than or equal to 80%.	The Balancing Authority Area's value of CPS2 is less than 80% but greater than or equal to 75%.	The Balancing Authority Area's value of CPS2 is less than 75%.
BAL-001-0.1a	R3.	Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.	N/A	N/A	N/A	The Balancing Authority providing Overlap Regulation Service failed to use a combined ACE and frequency bias.
BAL-001-0.1a	R4.	Any Balancing Authority receiving Overlap Regulation Service shall not	N/A	N/A	N/A	The Balancing Authority receiving

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		have its control performance evaluated (i.e. from a control performance perspective, the Balancing Authority has shifted all control requirements to the Balancing Authority providing Overlap Regulation Service).				Overlap Regulation Service failed to ensure that control performance was being evaluated in a manner consistent with the calculation methodology as described in BAL-001-01 R3.
BAL-002-1	R1.	Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.	N/A	N/A	N/A	The Balancing Authority does not have access to and/or operate Contingency Reserve to respond to Disturbances.
BAL-002-1	R1.1.	A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.	N/A	N/A	N/A	The Balancing Authority has elected to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group and the Reserve Sharing Group has not provided the same responsibilities and obligations as required of the responsible entity with respect to monitoring and meeting the requirements of Standard BAL-002.
BAL-002-1	R2.	Each Regional Reliability Organization, sub-Regional Reliability	The Regional Reliability	The Regional Reliability	The Regional Reliability	The Regional Reliability

Complete Violation Severity Level Matrix (BAL)
Encompassing All Commission-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:	Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify 1 of the following sub-requirements.	Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify 2 or 3 of the following sub-requirements.	Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify 4 or 5 of the following sub-requirements.	Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify all 6 of the following sub-requirements.
BAL-002-1	R2.1.	The minimum reserve requirement for the group.	N/A	N/A	N/A	The Regional Reliability Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify the minimum reserve requirement for the group.
BAL-002-1	R2.2.	Its allocation among members.	N/A	N/A	N/A	The Regional Reliability Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify the allocation of reserves among members.
BAL-002-1	R2.3.	The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.	N/A	N/A	N/A	The Regional Reliability Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify the permissible mix of Operating Reserve –

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.
BAL-002-1	R2.4.	The procedure for applying Contingency Reserve in practice.	N/A	N/A	N/A	The Regional Reliability Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to provide the procedure for applying Contingency Reserve in practice.
BAL-002-1	R2.5.	The limitations, if any, upon the amount of interruptible load that may be included.	N/A	N/A	N/A	The Regional Reliability Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has failed to specify the limitations, if any, upon the amount of interruptible load that may be included.
BAL-002-1	R2.6.	The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.	N/A	N/A	N/A	The Regional Reliability Organization, sub-Regional Reliability Organization, or Reserve Sharing Group has allowed the same portion of resource capacity (e.g., reserves from jointly owned generation) to be

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						counted more than once as Contingency Reserve by multiple Balancing Authorities.
BAL-002-1	R3.	Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.	The Balancing Authority or Reserve Sharing Group's Average Percent Recovery per the NERC DCS quarterly report was less than 100% but greater than or equal to 95%.	The Balancing Authority or Reserve Sharing Group's Average Percent Recovery per the NERC DCS quarterly report was less than 95% but greater than or equal to 90%.	The Balancing Authority or Reserve Sharing Group's Average Percent Recovery per the NERC DCS quarterly report was less than 90% but greater than or equal to 85%.	The Balancing Authority or Reserve Sharing Group's Average Percent Recovery per the NERC DCS quarterly report was less than 85%.
BAL-002-1	R3.1.	As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.	The Balancing Authority or Reserve Sharing Group failed to review their probable contingencies to determine their prospective most severe single contingencies annually.	N/A	N/A	The Balancing Authority or Reserve Sharing Group failed to carry at least enough Contingency Reserve to cover the most severe single contingency.
BAL-002-1	R4.	A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:	The Balancing Authority or Reserve Sharing Group met the Disturbance Recovery Criterion within the Disturbance Recovery Period for more than 90% and less than 100% of Reportable Disturbances.	The Balancing Authority or Reserve Sharing Group met the Disturbance Recovery Criterion within the Disturbance Recovery Period for more than 80% and less than or equal to 90% of Reportable Disturbances.	The Balancing Authority or Reserve Sharing Group met the Disturbance Recovery Criterion within the Disturbance Recovery Period for more than 70% and less than or equal to 80% of Reportable Disturbances.	The Balancing Authority or Reserve Sharing Group met the Disturbance Recovery Criterion within the Disturbance Recovery Period for more than 0% and less than or equal to 70% of Reportable Disturbances.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
BAL-002-1	R4.1.	A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.	N/A	N/A	N/A	The Balancing Authority failed to return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero or for negative initial ACE values failed to return ACE to its pre-Disturbance value.
BAL-002-1	R4.2.	The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance.	N/A	N/A	N/A	N/A
BAL-002-1	R5.	Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:	The Reserve Sharing Group met the DCS requirement for more than 90% and less than 100% of Reportable Disturbances.	The Reserve Sharing Group met the DCS requirements for more than 80% and less than or equal to 90% of Reportable Disturbances.	The Reserve Sharing Group met the DCS requirements for more than 70% and less than or equal to 80% of Reportable Disturbances.	The Reserve Sharing Group met the DCS requirements for more than 0% and less than or equal to 70% of Reportable Disturbances.
BAL-002-1	R5.1.	The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the	N/A	N/A	N/A	N/A

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.				
BAL-002-1	R5.2.	The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.	N/A	N/A	N/A	N/A
BAL-002-1	R6.	A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.	The Balancing Authority or Reserve Sharing Group restored less than 100% but greater than 90% of its contingency reserves during the Contingency Reserve Restoration Period.	The Balancing Authority or Reserve Sharing Group restored less than or equal to 90% but greater than 80% of its contingency reserves during the Contingency Reserve Restoration Period.	The Balancing Authority or Reserve Sharing Group restored less than or equal to 80% but greater than or equal to 70% of its Contingency Reserve during the Contingency Reserve Restoration Period.	The Balancing Authority or Reserve Sharing Group restored less than 70% of its Contingency Reserves during the Contingency Reserve Restoration Period.
BAL-002-1	R6.1.	The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.	N/A	N/A	N/A	N/A
BAL-002-1	R6.2.	The default Contingency Reserve Restoration Period is 90 minutes.	N/A	N/A	N/A	N/A
BAL-003-0.1b	R1.	Each Balancing Authority shall review its Frequency Bias Settings by January 1 of each year and recalculate its setting to reflect any change in the Frequency Response of the Balancing	The Balancing Authority failed to report the method for determining its Frequency Bias	The Balancing Authority failed to report its Frequency Bias Setting to the NERC Operating	The Balancing Authority failed to report its Frequency Bias Settings and the method for	The Balancing Authority failed to review its Frequency Bias Settings by January 1 of each year

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Authority Area.	Setting to the NERC Operating Committee. (R1.2)	Committee. (R1.2)	determining that Frequency Bias Setting to the NERC Operating Committee. (R1.2)	and recalculate its setting to reflect any change in the Frequency Response of the Balancing Authority Area.
BAL-003-0.1b	R1.1.	The Balancing Authority may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change.	N/A	N/A	N/A	N/A
BAL-003-0.1b	R1.2.	Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the NERC Operating Committee.	N/A	N/A	N/A	N/A
BAL-003-0.1b	R2.	Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be calculated several ways:	N/A	N/A	N/A	The Balancing Authority established and maintained a Frequency Bias Setting that was less than, the Balancing Authority's Frequency Response.
BAL-003-0.1b	R2.1.	The Balancing Authority may use a fixed Frequency Bias value which is based on a fixed, straight-line function of Tie Line deviation versus Frequency Deviation. The Balancing Authority shall determine the fixed value by observing and averaging the Frequency Response for several Disturbances during on-peak hours.	N/A	N/A	N/A	The Balancing Authority determination of the fixed Frequency Bias value was not based on observations and averaging the Frequency Response from Disturbances during on-peak hours.
BAL-003-0.1b	R2.2.	The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable	N/A	N/A	N/A	The Balancing Authorities variable frequency bias

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		function of Tie Line deviation to Frequency Deviation. The Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such as load, generation, governor characteristics, and frequency.				maintained was not based on analyses of Frequency Response as it varied with factors such as load, generation, governor characteristics, and frequency.
BAL-003-0.1b	R3.	Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.	N/A	N/A	N/A	The Balancing Authority did not operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, during periods when such operation would not have been adverse to system or Interconnection reliability.
BAL-003-0.1b	R4.	Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop response in their respective Frequency Bias Setting.	N/A	N/A	N/A	The Balancing Authority that used Dynamic Scheduling or Pseudo-ties for jointly owned units did not reflect its respective share of the unit governor droop response in its respective Frequency Bias Setting.
BAL-003-0.1b	R4.1.	Fixed schedules for Jointly Owned Units mandate that Balancing Authority (A) that contains the Jointly Owned Unit must incorporate the respective share of the unit governor droop response for any Balancing	N/A	N/A	N/A	The Balancing Authority (A) that contained the Jointly Owned Unit with fixed schedules did not incorporate the

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Authorities that have fixed schedules (B and C). See the diagram below.				respective share of the unit governor droop response for any Balancing Authorities that have fixed schedules (B and C).
BAL-003-0.1b	R4.2.	The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop response in their Frequency Bias Setting. ***See Standard for Graphic***	N/A	N/A	N/A	A Balancing Authority that has a fixed schedule (B and C) but does not contain the Jointly Owned Unit included its share of the governor droop response in its Frequency Bias Setting.
BAL-003-0.1b	R5.	Balancing Authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority's estimated yearly peak demand per 0.1 Hz change.	N/A	N/A	N/A	The Balancing Authority that served native load failed to have a monthly average Frequency Bias Setting that was at least 1% of the entities estimated yearly peak demand per 0.1 Hz change.
BAL-003-0.1b	R5.1.	Balancing Authorities that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.	N/A	N/A	N/A	The Balancing Authority that does not serve native load did not have a monthly average Frequency Bias Setting that was at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.

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BAL-003-0.1b	R6.	A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the entire area being controlled. A Balancing Authority shall not change its Frequency Bias Setting when performing Supplemental Regulation Service.	N/A	The Balancing Authority that was performing Overlap Regulation Service changed its Frequency Bias Setting while performing Supplemental Regulation Service.	The Balancing Authority that was performing Overlap Regulation Service failed to increase its Frequency Bias Setting to match the frequency response of the entire area being controlled.	N/A
BAL-004-0	R1.	Only a Reliability Coordinator shall be eligible to act as Interconnection Time Monitor. A single Reliability Coordinator in each Interconnection shall be designated by the NERC Operating Committee to serve as Interconnection Time Monitor.	N/A	N/A	N/A	The responsible entity has designated more than one interconnection time monitor for a single interconnection.
BAL-004-0	R2.	The Interconnection Time Monitor shall monitor Time Error and shall initiate or terminate corrective action orders in accordance with the NAESB Time Error Correction Procedure.	N/A	N/A	N/A	The responsible entity serving as the Interconnection Time Monitor failed to initiate or terminate corrective action orders in accordance with the NAESB Time Error Correction Procedure.
BAL-004-0	R3.	Each Balancing Authority, when requested, shall participate in a Time Error Correction by one of the following methods:	The Balancing Authority participated in more than 75% and less than 100% of requested Time Error Corrections for the calendar year.	The Balancing Authority participated in more than 50% and less than or equal to 75% of requested Time Error Corrections for the calendar year.	The Balancing Authority participated in more than 25% and less than or equal to 50% of requested Time Error Corrections for the calendar year.	The Balancing Authority participated in less than or equal to 25% of requested Time Error Corrections for the calendar year.
BAL-004-0	R3.1.	The Balancing Authority shall offset its frequency schedule by 0.02 Hertz,	The Balancing Authority failed to	The Balancing Authority failed to	The Balancing Authority failed to	The Balancing Authority failed to

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		leaving the Frequency Bias Setting normal; or	offset its frequency schedule by 0.02 Hertz and leave their Frequency Bias Setting normal for 0 to 25% of the time error corrections for the year.	offset its frequency schedule by 0.02 Hertz and leave their Frequency Bias Setting normal for 25 to 50% of the time error corrections for the year.	offset its frequency schedule by 0.02 Hertz and leave their Frequency Bias Setting normal for 50 to 75% of the time error corrections for the year.	offset its frequency schedule by 0.02 Hertz and leave their Frequency Bias Setting normal for 75% or more of the time error corrections for the year.
BAL-004-0	R.3.2.	The Balancing Authority shall offset its Net Interchange Schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz Frequency Deviation (i.e. 20% of the Frequency Bias Setting).	The Balancing Authority failed to offset its net interchange schedule frequency schedule by 20% of their frequency bias for 0 to 25% of the time error corrections.	The Balancing Authority failed to offset its net interchange schedule frequency schedule by 20% of their frequency bias for 25 to 50% of the time error corrections.	The Balancing Authority failed to offset its net interchange schedule frequency schedule by 20% of their frequency bias for 50 to 75% of the time error corrections.	The Balancing Authority failed to offset its net interchange schedule frequency schedule by 20% of their frequency bias for 75% or more of the time error corrections.
BAL-004-0	R4.	Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error Correction in progress, or a scheduled Time Error Correction that has not begun, for reliability considerations.	N/A	N/A	N/A	The RC serving as the Interconnection Time Monitor failed to initiate or terminate corrective action orders in accordance with the NAESB Time Error Correction Procedure.
BAL-004-0	R4.1.	Balancing Authorities that have reliability concerns with the execution of a Time Error Correction shall notify their Reliability Coordinator and request the termination of a Time Error Correction in progress.	N/A	N/A	N/A	The Balancing Authority with reliability concerns failed to notify the Reliability Coordinator and request the termination of a Time Error Correction in progress.
BAL-005-0.2b	R1.	All generation, transmission, and load operating within an Interconnection	N/A	N/A	N/A	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		must be included within the metered boundaries of a Balancing Authority Area.				
BAL-005-0.2b	R1.1.	Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.	N/A	N/A	N/A	The Generator Operator with generation facilities operating in an Interconnection failed to ensure that those generation facilities were included within metered boundaries of a Balancing Authority Area.
BAL-005-0.2b	R1.2.	Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.	N/A	N/A	N/A	The Transmission Operator with transmission facilities operating in an Interconnection failed to ensure that those transmission facilities were included within metered boundaries of a Balancing Authority Area.
BAL-005-0.2b	R1.3.	Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.	N/A	N/A	N/A	The Load-Serving Entity with load operating in an Interconnection failed to ensure that those loads were included within metered boundaries of a Balancing Authority Area.
BAL-005-0.2b	R2.	Each Balancing Authority shall maintain Regulating Reserve that can	N/A	N/A	N/A	The Balancing Authority failed to

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	(Retired)	be controlled by AGC to meet the Control Performance Standard.				maintain Regulating Reserve that can be controlled by AGC to meet Control Performance Standard.
BAL-005-0.2b	R3.	A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.	N/A	N/A	N/A	The Balancing Authority providing Regulation Service failed to ensure adequate metering, communications, and control equipment was provided.
BAL-005-0.2b	R4.	A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.	N/A	N/A	N/A	The Balancing Authority providing Regulation Service failed to notify the Host Balancing Authority for whom it is controlling if it was unable to provide the service, as well as any Intermediate Balancing Authorities.
BAL-005-0.2b	R5.	A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.	N/A	N/A	N/A	The Balancing Authority receiving Regulation Service failed to ensure that back-up plans were in place to provide replacement Regulation Service.
BAL-005-0.2b	R6.	The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's	The Balancing Authority failed to notify the Reliability Coordinator within 30 minutes of its	The Balancing Authority failed to calculate ACE as specified in the	N/A	The Balancing Authority failed to notify the Reliability Coordinator within 30 minutes of its inability

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.	inability to calculate ACE.	requirement.		to calculate ACE and failed to use the ACE calculation specified in the requirement in its attempt to calculate ACE.
BAL-005-0.2b	R7.	The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.	N/A	N/A	N/A	The Balancing Authority failed to operate AGC continuously when there were no adverse impacts. OR If its AGC was inoperative the Balancing Authority failed to use manual control to adjust generation to maintain the Net Scheduled Interchange.
BAL-005-0.2b	R8.	The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.	N/A	N/A	N/A	The Balancing Authority failed to ensure that data acquisition for and calculation of ACE occurred at least every six seconds.
BAL-005-0.2b	R8.1.	Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of	N/A	N/A	N/A	The Balancing Authority failed to provide redundant and independent frequency metering equipment that automatically activated upon

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		99.95%.				detection of failure, such that the minimum availability was less than 99.95%.
BAL-005-0.2b	R9.	The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.	N/A	N/A	N/A	The Balancing Authority failed to include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.
BAL-005-0.2b	R9.1.	Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.	N/A	N/A	N/A	The Balancing Authority with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to its Interconnection chose to omit the Interchange Schedule related to the HVDC link from the ACE equation, but failed to model it as internal generation or load.
BAL-005-0.2b	R10.	The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.	N/A	N/A	N/A	The Balancing Authority failed to include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.
BAL-005-0.2b	R11.	Balancing Authorities shall include the effect of Ramp rates, which shall	N/A	N/A	N/A	The Balancing Authority failed to

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		be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.				include the effect of Ramp rates in the Scheduled Interchange values to calculate ACE.
BAL-005-0.2b	R12.	Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.	N/A	N/A	N/A	The Balancing Authority failed to include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.
BAL-005-0.2b	R12.1.	Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.	The Balancing Authority failed to ensure 5% or less of all its Tie Line MW metering was telemetered to both control centers and emanates from a common, agreed-upon source OR The Balancing Authority failed to ensure that megawatt-hour data was telemetered or reported for 5% or less of the hours.	The Balancing Authority failed to ensure more than 5% up to (and including) 10% of all its Tie Line MW metering was telemetered to both control centers and emanates from a common, agreed-upon source. OR The Balancing Authority failed to ensure that megawatt-hour data was telemetered or reported for more than 5% up to (and including) 10% of the hours.	The Balancing Authority failed to ensure more than 10% up to (and including) 15% of all its Tie Line MW metering was telemetered to both control centers and emanates from a common, agreed-upon source. OR The Balancing Authority failed to ensure that megawatt-hour data was telemetered or reported for more than 10% up to (and including) 15% of the hours.	The Balancing Authority failed to ensure more than 15% of all its Tie Line MW metering was telemetered to both control centers and emanates from a common, agreed-upon source. OR The Balancing Authority failed to ensure that megawatt-hour data was telemetered or reported for more than 15% of the hours.
BAL-005-0.2b	R12.2.	Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are	The responsible entity did not ensure that 5% or less of the power flow and ACE signals are not	The responsible entity did not ensure that more than 5% up to (and including) 10% of the power flow and	The responsible entity did not ensure that more than 10% up to (and including) 15% of the power flow and	The responsible entity did not ensure that more than 15% of the power flow and ACE signals are not filtered

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.	filtered except for Anti-aliasing filtering.	ACE signals are not filtered except for Anti-aliasing filtering.	ACE signals are not filtered except for Anti-aliasing filtering.	except for Anti-aliasing filtering.
BAL-005-0.2b	R12.3.	Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.	N/A	N/A	N/A	The applicable entity did not install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented.
BAL-005-0.2b	R13.	Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (IME) term of the ACE equation to compensate for any equipment error until repairs can be made.	N/A	N/A	N/A	The Balancing Authority failed to perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment OR the Balancing Authority failed to adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (IME) term of the ACE equation to compensate for any equipment error until repairs can be made.
BAL-005-0.2b	R14.	The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation	N/A	N/A	N/A	The Balancing Authority failed to provide its operating personnel with sufficient

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.				instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance.
BAL-005-0.2b	R15.	The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.	N/A	N/A	The Balancing Authority failed to periodically test backup power supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.	The Balancing Authority failed to provide adequate and reliable backup power supplies to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.
BAL-005-0.2b	R16.	The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.	The Balancing Authority failed to collect coincident data to the greatest practical extent.	N/A	The Balancing Authority failed to flag missing or bad data for operator display and archival purposes.	The Balancing Authority failed to sample data at least at the same periodicity with which ACE is calculated.
BAL-005-0.2b	R17.	Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices	N/A	N/A	N/A	The Balancing Authority failed to at least annually check

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		against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below: ***See Standard for Values***				and calibrate its time error and frequency devices against a common reference.
BAL-006-2	R1.	Each Balancing Authority shall calculate and record hourly Inadvertent Interchange.	N/A	N/A	N/A	Each Balancing Authority failed to calculate and record hourly Inadvertent Interchange.
BAL-006-2	R2.	Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators.	N/A	N/A	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. OR Failed to take into account interchange served by jointly owned generators.	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. AND Failed to take into account interchange served by jointly owned generators.
BAL-006-2	R3.	Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.	N/A	N/A	N/A	The Balancing Authority failed to ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Balancing Authorities.
BAL-006-2	R4.	Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following:	The Balancing Authority failed to record Actual Net Interchange values that are equal but opposite in sign to its Adjacent Balancing Authorities.	The Balancing Authority failed to compute Inadvertent Interchange.	The Balancing Authority failed to operate to a common Net Interchange Schedule that is equal but opposite to its Adjacent Balancing Authorities.	N/A
BAL-006-2	R4.1	Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to:	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule. AND The hourly integrated megawatt-hour values of Net Actual Interchange.
BAL-006-2	R4.1.1.	The hourly values of Net Interchange Schedule.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
BAL-006-2	R4.1.2.	The hourly integrated megawatt-hour values of Net Actual Interchange.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly integrated megawatt-hour values of Net Actual Interchange.
BAL-006-2	R4.2.	Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.	N/A	N/A	N/A	The Balancing Authority failed to use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.
BAL-006-2	R4.3.	A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies).	N/A	N/A	N/A	The Balancing Authority failed to make after-the-fact corrections to the agreed-to daily and monthly accounting data to reflect actual operating conditions or changes or corrections based on non-reliability considerations were reflected in the Balancing Authority's Inadvertent Interchange.
BAL-006-2	R5.	Adjacent Balancing Authorities that	Adjacent Balancing	Adjacent Balancing	N/A	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy.	Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities, submitted a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute but failed to provide a process for correcting the discrepancy.	Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month, failed to submit a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute as well as a process for correcting the discrepancy.		
BAL-502-RFC-02	R1.	The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall: *[See standard pdf for sub-requirements]*	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they were not included OR The Planning	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from R1.1 as a percentage of the net Median forecast peak Load per R1.1.2 OR The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per R1.2 OR The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. OR The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per R1.5	subcomponents under R1.3.1 and documentation of its use OR The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under R1.3.2 and documentation of its use Or The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per R1.7	period or both per R1.2.2 OR The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Load forecast Characteristics subcomponents under R1.3.1 and documentation of their use OR The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under R1.3.2 and documentation of their use OR The Planning Coordinator Resource Adequacy analysis failed to include Transmission	peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per R1.1 OR The Planning Coordinator failed to perform an analysis for Year One per R1.2.1

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					limitations and documentation of its use per R1.3.3 OR The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per R1.3.4 OR The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they were not included OR The Planning Coordinator Resource	

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per R1.6	
BAL-502-RFC-02	R2.	The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis. *[See standard pdf for sub-requirements]*	The Planning Coordinator failed to publicly post the documents as specified per requirement R2.1 and R2.2 later than 30 calendar days prior to the beginning of Year One per R2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per R2.1. OR The Planning Coordinator failed to document the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per R2.2.	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per R2.1. OR The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per R2.1.	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per R2.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
CIP-001-2a	R1.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection.	N/A	N/A	The responsible entity has procedures for the recognition of sabotage events on its facilities and multi site sabotage affecting larger portions of the Interconnection but does not have a procedure for making their operating personnel aware of said events.	The responsible entity failed to have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi site sabotage affecting larger portions of the Interconnection.
CIP-001-2a	R2.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.	N/A	N/A	The responsible entity has demonstrated the existence of a procedure to communicate information concerning sabotage events, but not all of the appropriate parties in the interconnection are identified.	The responsible entity failed to have a procedure for communicating information concerning sabotage events.
CIP-001-2a	R3.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to	N/A	The responsible entity provided its operating personnel with a sabotage response guideline, but failed to include the personnel to contact for reporting disturbances due to	N/A	The responsible entity failed to provide its operating personnel with a sabotage response guideline.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		sabotage events.		sabotage events.		
CIP-001-2a	R4. (Retired)	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.	N/A	N/A	The responsible entity has established communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials, but has not developed a reporting procedure.	The responsible entity failed to establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials, and has not developed a reporting procedure.
CIP-002-3	R1.	Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.	N/A	N/A	N/A	The responsible entity has not documented a risk-based assessment methodology to use to identify its Critical Assets as specified in R1.
CIP-002-3	R1.1	The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.	N/A	The Responsible Entity maintained documentation describing its risk-based assessment methodology which includes evaluation criteria, but does not include procedures.	The Responsible Entity maintained documentation describing its risk-based assessment methodology that includes procedures but does not include evaluation criteria.	The Responsible Entity did not maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
CIP-002-3	R1.2	The risk-based assessment shall consider the following assets:	N/A	N/A	N/A	The Responsible Entity did not consider all of the asset types listed in

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						R1.2.1 through R1.2.7 in its risk-based assessment.
CIP-002-3	R1.2.1.	Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.	N/A	N/A	N/A	N/A
CIP-002-3	R1.2.2.	Transmission substations that support the reliable operation of the Bulk Electric System.	N/A	N/A	N/A	N/A
CIP-002-3	R1.2.3.	Generation resources that support the reliable operation of the Bulk Electric System.	N/A	N/A	N/A	N/A
CIP-002-3	R1.2.4.	Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.	N/A	N/A	N/A	N/A
CIP-002-3	R1.2.5.	Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.	N/A	N/A	N/A	N/A
CIP-002-3	R1.2.6.	Special Protection Systems that support the reliable operation of the Bulk Electric System.	N/A	N/A	N/A	N/A
CIP-002-3	R1.2.7.	Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.	N/A	N/A	N/A	N/A
CIP-002-3	R2.	Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-	N/A	N/A	The Responsible Entity has developed a list of Critical Assets but the list has	The Responsible Entity did not develop a list of its identified Critical

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.			not been reviewed and updated annually as required.	Assets even if such list is null.
CIP-002-3	R3.	Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:	N/A	N/A	The Responsible Entity has developed a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 but the list has not been reviewed and updated annually as required.	The Responsible Entity did not develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 even if such list is null.
CIP-002-3	R3.1	The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,	N/A	N/A	N/A	A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.
CIP-002-3	R3.2.	The Cyber Asset uses a routable protocol within a control center; or,	N/A	N/A	N/A	A Cyber Asset essential to the operation of the Critical Asset was

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.
CIP-002-3	R3.3.	The Cyber Asset is dial-up accessible.	N/A	N/A	N/A	A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.
CIP-002-3	R4.	Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)	N/A	The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual approval of the risk-based assessment methodology, the list of Critical Assets or the list of Critical Cyber Assets (even if such lists are null.)	The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual approval of two of the following: the risk-based assessment methodology, the list of Critical Assets or the list of Critical Cyber Assets (even if such lists are null.)	The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s) annual approval of 1) A risk based assessment methodology for identification of Critical Assets, 2) a signed and dated approval of the list of Critical Assets, nor 3) a signed and dated approval of the list of Critical Cyber Assets (even if such lists are null.)
CIP-002-4	R1.		N/A	N/A	The Responsible	The Responsible

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		Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the criteria contained in CIP-002-4 Attachment 1 – Critical Asset Criteria. The Responsible Entity shall update this list as necessary, and review it at least annually.			Entity has developed a list of Critical Assets but the list has not been reviewed and updated annually as required.	Entity did not develop a list of its identified Critical Assets even if such list is null.
CIP-002-4	R2.	Critical Cyber Asset Identification— Using the list of Critical Assets developed pursuant to Requirement R1, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. The Responsible Entity shall update this list as necessary, and review it at least annually. For each group of generating units (including nuclear generation) at a single plant location identified in Attachment 1, criterion 1.1, the only Cyber Assets that must be considered are those shared Cyber Assets that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed Attachment 1, criterion 1.1. For the purpose of Standard CIP-002-4, Critical Cyber Assets are	N/A	N/A	The Responsible Entity has developed a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 but the list has not been reviewed and updated annually as required.	The Responsible Entity did not develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 even if such list is null. OR A Cyber Asset essential to the operation of the Critical Asset was identified that met at least one of the bulleted characteristics in this requirement but was not included in the Critical Cyber

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		further qualified to be those having at least one of the following characteristics: • The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or, • The Cyber Asset uses a routable protocol within a control center; or, • The Cyber Asset is dial-up accessible.				Asset List.
CIP-002-4	R3.	Annual Approval —The senior manager or delegate(s) shall approve annually the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1 and R2 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)	N/A	N/A	The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual approval of the list of Critical Assets. OR The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual approval of the list of Critical Cyber Assets (even if such lists are null.)	The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual approval of both the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)
CIP-003-3	R1.	Cyber Security Policy — The Responsible Entity shall document and	N/A	N/A	N/A	The Responsible Entity has not

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		implement a cyber security policy that represents management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:				documented or implemented a cyber security policy.
CIP-003-3	R1.1.	The cyber security policy addresses the requirements in Standards CIP-002-3 through CIP-009-3, including provision for emergency situations.	N/A	N/A	N/A	The Responsible Entity's cyber security policy does not address all the requirements in Standards CIP-002 through CIP-009, including provision for emergency situations.
CIP-003-3	R1.2. (Retired)	The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.	N/A	N/A	N/A	The Responsible Entity's cyber security policy is not readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.
CIP-003-3	R1.3	Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.	N/A	N/A	N/A	The Responsible Entity's senior manager, assigned pursuant to R2, did not complete the annual review and approval of its cyber security policy.
CIP-003-3	R2.	Leadership — The Responsible Entity shall assign a senior manager with overall responsibility for leading and managing the entity's implementation of, and adherence to, Standards CIP-002-3	N/A	N/A	N/A	The Responsible Entity has not assigned a single senior manager with overall responsibility and authority for

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		through CIP-009-3.				leading and managing the entity's implementation of, and adherence to, Standards CIP-002 through CIP-009.
CIP-003-3	R2.1.	The senior manager shall be identified by name, title, and date of designation.	N/A	N/A	N/A	Identification of the senior manager is missing one of the following: name, title, or date of designation.
CIP-003-3	R2.2.	Changes to the senior manager must be documented within thirty calendar days of the effective date.	N/A	N/A	N/A	Changes to the senior manager were not documented within 30 days of the effective date.
CIP-003-3	R2.3.	Where allowed by Standards CIP-002-3 through CIP-009-3, the senior manager may delegate authority for specific actions to a named delegate or delegates. These delegations shall be documented in the same manner as R2.1 and R2.2, and approved by the senior manager.	N/A	N/A	The identification of a senior manager's delegate does not include at least one of the following; name, title, or date of the designation, OR The document is not approved by the senior manager, OR Changes to the delegated authority	A senior manager's delegate is not identified by name, title, and date of designation; the document delegating the authority does not identify the authority being delegated; the document delegating the authority is not approved by the senior manager; AND changes to the delegated authority are not documented

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					are not documented within thirty calendar days of the effective date.	within thirty calendar days of the effective date.
CIP-003-3	R2.4	The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.	N/A	N/A	N/A	The senior manager or delegate(s) did not authorize and document any exceptions from the requirements of the cyber security policy as required.
CIP-003-3	R3. (Retired)	Exceptions — Instances where the Responsible Entity cannot conform to its ~~cyber security policy must be~~ documented as exceptions and authorized by the senior manager or delegate(s).	N/A	N/A	In Instances where the Responsible Entity cannot conform to its cyber security policy, in R1, exceptions were documented, but were not authorized by the senior manager or delegate(s).	In Instances where the Responsible Entity cannot conform to its cyber security policy, in R1, exceptions were not documented.
CIP-003-3	R3.1. (Retired)	Exceptions to the Responsible Entity's cyber security policy must be ~~documented within thirty days of being~~ approved by the senior manager or delegate(s).	N/A	N/A	N/A	Exceptions to the Responsible Entity's cyber security policy were not documented within 30 days of being approved by the senior manager or delegate(s).
CIP-003-3	R3.2. (Retired)	Documented exceptions to the cyber security policy must include an ~~explanation as to why the exception is~~ necessary and any compensating measures.	N/A	N/A	The Responsible Entity has a documented exception to the cyber security policy in R1 but did not	The Responsible Entity has a documented exception to the cyber security policy in R1 but did not

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					include either: 1) an explanation as to why the exception is necessary, or 2) any compensating measures.	include both: 1) an explanation as to why the exception is necessary, and 2) any compensating measures.
CIP-003-3	R3.3. (Retired)	Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.	N/A	N/A	N/A	Exceptions to the cyber security policy were not reviewed or were not approved on an annual basis by the senior manager or delegate(s) to ensure the exceptions are still required and valid or the review and approval is not documented.
CIP-003-3	R4.	Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.	N/A	N/A	N/A	The Responsible Entity did not implement or did not document a program to identify, classify, and protect information associated with Critical Cyber Assets.
CIP-003-3	R4.1.	The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP- 002-3, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans,	N/A	N/A	The information protection program does not include one of the minimum information types to be protected as detailed in R4.1.	The information protection program does not include two or more of the minimum information types to be protected as detailed in R4.1.

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		incident response plans, and security configuration information.				
CIP-003-3	R4.2. (Retired)	The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.	N/A	N/A	N/A	The Responsible Entity did not classify the information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.
CIP-003-3	R4.3.	The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.	N/A	N/A	N/A	The Responsible Entity did not annually assess adherence to its Critical Cyber Asset information protection program, including documentation of the assessment results, OR The Responsible Entity did not implement an action plan to remediate deficiencies identified during the assessment.
CIP-003-3	R5.	Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.	N/A	N/A	N/A	The Responsible Entity did not implement or did not document a program for managing access to protected Critical Cyber Asset information.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
CIP-003-3	R5.1.	The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.	N/A	N/A	The Responsible Entity maintained a list of designated personnel for authorizing either logical or physical access but not both.	The Responsible Entity did not maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.
CIP-003-3	R5.1.1.	Personnel shall be identified by name, title, and the information for which they are responsible for authorizing access.	N/A	N/A	The Responsible Entity did identify the personnel by name, title, and the information for which they are responsible for authorizing access, but the business phone is missing.	Personnel are not identified by name, title, or the information for which they are responsible for authorizing access.
CIP-003-3	R5.1.2.	The list of personnel responsible for authorizing access to protected information shall be verified at least annually.	N/A	N/A	N/A	The Responsible Entity did not verify at least annually the list of personnel responsible for authorizing access to protected information.
CIP-003-3	R5.2.	The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.	N/A	N/A	N/A	The Responsible Entity did not review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						needs and appropriate personnel roles and responsibilities.
CIP-003-3	R5.3.	The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.	N/A	N/A	N/A	The Responsible Entity did not assess and document at least annually the processes for controlling access privileges to protected information.
CIP-003-3	R6.	Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendor related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.	N/A	N/A	N/A	The Responsible Entity has not established or documented a change control process for the activities required in R6, OR The Responsible Entity has not established or documented a configuration management process for the activities required in R6.
CIP-003-4	R1.	Cyber Security Policy —The Responsible Entity shall document and implement a cyber security policy that represents management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:	N/A	N/A	The Responsible Entity has documented but not implemented a cyber security policy.	The Responsible Entity has not documented nor implemented a cyber security policy.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
CIP-003-4	R1.1.	The cyber security policy addresses the requirements in Standards CIP-002-4 through CIP-009-4, including provision for emergency situations.	N/A	N/A	N/A	The Responsible Entity's cyber security policy does not address all the requirements in Standards CIP-002-4 through CIP-009-4, including provision for emergency situations.
CIP-003-4	R1.2. (Retired)	The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.	N/A	N/A	N/A	The Responsible Entity's cyber security policy is not readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.
CIP-003-4	R1.3.	Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.	N/A	N/A	The Responsible Entity's senior manager, assigned pursuant to R2, annually reviewed but did not annually approve its cyber security policy.	The Responsible Entity's senior manager, assigned pursuant to R2, did not annually review nor approve its cyber security policy.
CIP-003-4	R2.	Leadership —The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity's implementation of, and adherence to, Standards CIP-002-4 through CIP-009-4.	N/A	N/A	N/A	The Responsible Entity has not assigned a single senior manager with overall responsibility and authority for leading and managing the entity's

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Complete Violation Severity Level Matrix (CIP)
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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						implementation of, and adherence to, Standards CIP-002-4 through CIP-009-4.
CIP-003-4	R2.1.	The senior manager shall be identified by name, title, and date of designation.	N/A	N/A	N/A	The senior manager is not identified by name, title, and date of designation.
CIP-003-4	R2.2.	Changes to the senior manager must be documented within thirty calendar days of the effective date.	Changes to the senior manager were documented in greater than 30 but less than 60 days of the effective date.	Changes to the senior manager were documented in 60 or more but less than 90 days of the effective date.	Changes to the senior manager were documented in 90 or more but less than 120 days of the effective date.	Changes to the senior manager were documented in 120 or more days of the effective date.
CIP-003-4	R2.3.	Where allowed by Standards CIP-002-4 through CIP-009-4, the senior manager may delegate authority for specific actions to a named delegate or delegates. These delegations shall be documented in the same manner as R2.1 and R2.2, and approved by the senior manager.	N/A	N/A	The identification of a senior manager's delegate does not include at least one of the following; name, title, or date of the designation, OR The document is not approved by the senior manager, OR Changes to the delegated authority are not documented within thirty calendar days of the effective date.	A senior manager's delegate is not identified by name, title, and date of designation; the document delegating the authority does not identify the authority being delegated; the document delegating the authority is not approved by the senior manager; AND changes to the delegated authority are not documented within thirty calendar days of the effective date.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
CIP-003-4	R2.4.	The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.	N/A	N/A	N/A	The senior manager or delegate(s) did not authorize and document any exceptions from the requirements of the cyber security policy as required.
CIP-003-4	R3. (Retired)	Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).	N/A	N/A	In Instances where the Responsible Entity cannot conform to its cyber security policy (pertaining to CIP 002 through CIP 009), exceptions were documented, but were not authorized by the senior manager or delegate(s).	In Instances where the Responsible Entity cannot conform to its cyber security policy (pertaining to CIP 002 through CIP 009), exceptions were not documented, and were not authorized by the senior manager or delegate(s).
CIP-003-4	R3.1. (Retired)	Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).	Exceptions to the Responsible Entity's cyber security policy were documented in more than 30 but less than 60 days of being approved by the senior manager or delegate(s).	Exceptions to the Responsible Entity's cyber security policy were documented in 60 or more but less than 90 days of being approved by the senior manager or delegate(s).	Exceptions to the Responsible Entity's cyber security policy were documented in 90 or more but less than 120 days of being approved by the senior manager or delegate(s).	Exceptions to the Responsible Entity's cyber security policy were documented in 120 or more days of being approved by the senior manager or delegate(s).
CIP-003-4	R3.2. (Retired)	Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating	N/A	N/A	The Responsible Entity has a documented exception to the	The Responsible Entity has a documented exception to the

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		measures.			cyber security policy (pertaining to CIP 002-4 through CIP 009-4) but did not include either: 1) an explanation as to why the exception is necessary, or 2) any compensating measures.	cyber security policy (pertaining to CIP 002-4 through CIP 009-4) but did not include both: 1) an explanation as to why the exception is necessary, and 2) any compensating measures.
CIP-003-4	R3.3. (Retired)	Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.	N/A	N/A	Exceptions to the cyber security policy (pertaining to CIP 002-4 through CIP 009-4) were reviewed but not approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid.	Exceptions to the cyber security policy (pertaining to CIP 002-4 through CIP 009-4) were not reviewed nor approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid.
CIP-003-4	R4.	Information Protection —The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.	N/A	The Responsible Entity implemented but did not document a program to identify, classify, and protect information associated with Critical Cyber Assets.	The Responsible Entity documented but did not implement a program to identify, classify, and protect information associated with Critical Cyber Assets.	The Responsible Entity did not implement nor document a program to identify, classify, and protect information associated with Critical Cyber Assets.
CIP-003-4	R4.1.	The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002-4, network topology or similar	N/A	N/A	The information protection program does not include one of the minimum information types to	The information protection program does not include two or more of the minimum

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.			be protected as detailed in R4.1.	information types to be protected as detailed in R4.1.
CIP-003-4	R4.2. (Retired)	The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.	N/A	N/A	N/A	The Responsible Entity did not classify the information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.
CIP-003-4	R4.3.	The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.	N/A	The Responsible Entity annually assessed adherence to its Critical Cyber Asset information protection program, documented the assessment results, which included deficiencies identified during the assessment but did not implement a remediation plan.	The Responsible Entity annually assessed adherence to its Critical Cyber Asset information protection program, did not document the assessment results, and did not implement a remediation plan.	The Responsible Entity did not annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, nor implement an action plan to remediate deficiencies identified during the assessment.
CIP-003-4	R5.	Access Control —The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.	N/A	The Responsible Entity implemented but did not document a program for managing access to protected	The Responsible Entity documented but did not implement a program for managing access	The Responsible Entity did not implement nor document a program for managing access

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Critical Cyber Asset information.	to protected Critical Cyber Asset information.	to protected Critical Cyber Asset information.
CIP-003-4	R5.1.	The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.	N/A	N/A	The Responsible Entity maintained a list of designated personnel for authorizing either logical or physical access but not both.	The Responsible Entity did not maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.
CIP-003-4	R5.1.1.	Personnel shall be identified by name, title, and the information for which they are responsible for authorizing access.	N/A	N/A	The Responsible Entity did identify the personnel by name and title but did not identify the information for which they are responsible for authorizing access.	The Responsible Entity did not identify the personnel by name and title nor the information for which they are responsible for authorizing access.
CIP-003-4	R5.1.2.	The list of personnel responsible for authorizing access to protected information shall be verified at least annually.	N/A	N/A	N/A	The Responsible Entity did not verify at least annually the list of personnel responsible for authorizing access to protected information.
CIP-003-4	R5.2.	The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel	N/A	N/A	N/A	The Responsible Entity did not review at least annually the access privileges to protected information to confirm that access

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		roles and responsibilities.				privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.
CIP-003-4	R5.3.	The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.	N/A	N/A	N/A	The Responsible Entity did not assess and document at least annually the processes for controlling access privileges to protected information.
CIP-003-4	R6.	Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendor-related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.	The Responsible Entity has established but not documented a change control process OR The Responsible Entity has established but not documented a configuration management process.	The Responsible Entity has established but not documented both a change control process and configuration management process.	The Responsible Entity has not established and documented a change control process OR The Responsible Entity has not established and documented a configuration management process.	The Responsible Entity has not established and documented a change control process AND The Responsible Entity has not established and documented a configuration management process.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
CIP-004-3	R1.	Awareness — The Responsible Entity shall establish, document, implement, and maintain a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets receive on-going reinforcement in sound security practices. The program shall include security awareness reinforcement on at least a quarterly basis using mechanisms such as: • Direct communications (e.g. emails, memos, computer based training, etc.); • Indirect communications (e.g. posters, intranet, brochures, etc.); • Management support and reinforcement (e.g., presentations, meetings, etc.).	N/A	N/A	The Responsible[1] Entity did not provide security awareness reinforcement on at least a quarterly basis.	The Responsible Entity did not establish, implement, maintain, or document a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets receive on-going reinforcement in sound security practices.
CIP-004-3	R2.	Training — The Responsible Entity shall establish, document, implement, and maintain an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. The cyber security training program shall be reviewed annually, at a minimum, and shall be	N/A	N/A	The Responsible[2] Entity did not review the training program on an annual basis.	The Responsible Entity did not establish, implement, maintain, or document an annual cyber security training program for personnel having authorized cyber or authorized unescorted

[1] Please note that FERC's January 20, 2011 Order on Version 2 And Version 3 Violation Risk Factors And Violation Severity Levels For Critical Infrastructure Protection Reliability Standards dictated "Responsible Entity" to be changed to "Responsibility Entity." NERC assumes FERC intended the VSL to read "Responsible Entity" and therefore is not making this change. NERC proposes to remove this footnote from the final approved list of VSLs.

[2] Please see previous footnote. NERC proposes to remove this footnote from the final approved list of VSLs.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		updated whenever necessary.				physical access to Critical Cyber Assets.
CIP-004-3	R2.1.	This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained prior to their being granted such access except in specified circumstances such as an emergency.	N/A	N/A	N/A	Not all personnel having authorized cyber or unescorted physical access to Critical Cyber Assets, including contractors and service vendors, were trained prior to their being granted such access except in specified circumstances such as an emergency.
CIP-004-3	R2.2.	Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004-3, and include, at a minimum, the following required items appropriate to personnel roles and responsibilities:	N/A	N/A	N/A	The training does not include one or more of the minimum topics as detailed in R2.2.1, R2.2.2, R2.2.3, R2.2.4.
CIP-004-3	R2.2.1.	The proper use of Critical Cyber Assets;	N/A	N/A	N/A	N/A
CIP-004-3	R2.2.2.	Physical and electronic access controls to Critical Cyber Assets;	N/A	N/A	N/A	N/A
CIP-004-3	R2.2.3.	The proper handling of Critical Cyber Asset information; and,	N/A	N/A	N/A	N/A
CIP-004-3	R2.2.4.	Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.	N/A	N/A	N/A	N/A
CIP-004-3	R2.3.	The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and attendance records.	N/A	N/A	The Responsible Entity did maintain documentation that training is conducted at least annually, but	The Responsible Entity did not maintain documentation that training is conducted

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					did not include attendance records.	at least annually, including the date the training was completed and attendance records.
CIP-004-3	R3.	Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. A personnel risk assessment shall be conducted pursuant to that program prior to such personnel being granted such access except in specified circumstances such as an emergency. The personnel risk assessment program shall at a minimum include:	N/A	The Responsible Entity has a personnel risk assessment program, as stated in R3, for personnel having authorized cyber or authorized unescorted physical access, but the program is not documented.	The Responsible Entity has a personnel risk assessment program as stated in R3, but conducted the personnel risk assessment pursuant to that program after such personnel were granted such access except in specified circumstances such as an emergency.	The Responsible Entity does not have a documented personnel risk assessment program, as stated in R3, for personnel having authorized cyber or authorized unescorted physical access. OR The Responsible Entity did not conduct the personnel risk assessment pursuant to that program for personnel granted such access except in specified circumstances such as an emergency.
CIP-004-3	R3.1.	The Responsible Entity shall ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and seven year criminal check. The Responsible Entity may conduct more detailed reviews, as permitted by law and subject to existing collective bargaining unit agreements, depending upon the	N/A	N/A	The Responsible Entity did not ensure that an assessment conducted included an identity verification (e.g., Social Security Number verification	The Responsible Entity did not ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		criticality of the position.			in the U.S.) or a seven-year criminal check.	in the U.S.) and seven-year criminal check.
CIP-004-3	R3.2.	The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.	N/A	The Responsible Entity did not update each personnel risk assessment at least every seven years after the initial personnel risk assessment but did update it for cause when applicable.	The Responsible Entity did not update each personnel risk assessment for cause (when applicable) but did at least updated it every seven years after the initial personnel risk assessment.	The Responsible Entity did not update each personnel risk assessment at least every seven years after the initial personnel risk assessment nor was it updated for cause when applicable.
CIP-004-3	R3.3.	The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and that personnel risk assessments of contractor and service vendor personnel with such access are conducted pursuant to Standard CIP-004-3.	The Responsible Entity did not document the results of personnel risk assessments for at least one individual but less than 5% of all personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, pursuant to Standard CIP-004.	The Responsible Entity did not document the results of personnel risk assessments for 5% or more but less than 10% of all personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, pursuant to Standard CIP-004.	The Responsible Entity did not document the results of personnel risk assessments for 10% or more but less than 15% of all personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, pursuant to Standard CIP-004.	The Responsible Entity did not document the results of personnel risk assessments for 15% or more of all personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, pursuant to Standard CIP-004.
CIP-004-3	R4.	Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets.	The Responsible Entity did not maintain complete list(s) of personnel with authorized cyber or authorized unescorted	The Responsible Entity did not maintain complete list(s) of personnel with authorized cyber or authorized unescorted physical access to	The Responsible Entity did not maintain complete list(s) of personnel with authorized cyber or authorized unescorted physical	The Responsible Entity did not maintain complete list(s) of personnel with authorized cyber or authorized unescorted physical

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets, missing at least one individual but less than 5% of the authorized personnel.	Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets, missing 5% or more but less than 10% of the authorized personnel.	access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets, missing 10% or more but less than 15%of the authorized personnel.	access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets, missing 15% or more of the authorized personnel.
CIP-004-3	R4.1.	The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, or any change in the access rights of such personnel. The Responsible Entity shall ensure access list(s) for contractors and service vendors are properly maintained.	N/A	The Responsible Entity did not review the list(s) of its personnel who have access to Critical Cyber Assets quarterly.	The Responsible Entity did not update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, nor any change in the access rights of such personnel.	The Responsible Entity did not review the list(s) of all personnel who have access to Critical Cyber Assets quarterly, nor update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, nor any change in the access rights of such personnel.
CIP-004-3	R4.2.	The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.	N/A	The Responsible Entity did not revoke access within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.	The Responsible Entity did not revoke access to Critical Cyber Assets within 24 hours for personnel terminated for cause.	The Responsible Entity did not revoke access to Critical Cyber Assets within 24 hours for personnel terminated for cause nor within seven calendar days for personnel who no

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						longer require such access to Critical Cyber Assets.
CIP-004-4	R1.	Awareness —The Responsible Entity shall establish, document, implement, and maintain a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets receive on-going reinforcement in sound security practices. The program shall include security awareness reinforcement on at least a quarterly basis using mechanisms such as: • Direct communications (e.g., emails, memos, computer based training, etc.); • Indirect communications (e.g., posters, intranet, brochures, etc.); • Management support and reinforcement (e.g., presentations, meetings, etc.).	The Responsible Entity established, implemented, and maintained but did not document a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets receive ongoing reinforcement in sound security practices.	The Responsibility Entity did not provide security awareness reinforcement on at least a quarterly basis.	The Responsible Entity did document but did not establish, implement, nor maintain a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets receive on-going reinforcement in sound security practices.	The Responsible Entity did not establish, implement, maintain, nor document a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets receive on-going reinforcement in sound security practices.
CIP-004-4	R2.	Training —The Responsible Entity shall establish, document, implement, and maintain an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. The cyber security training program shall be reviewed annually, at a minimum, and shall be updated whenever necessary.	The Responsible Entity established, implemented, and maintained but did not document an annual cyber security training program for personnel having authorized cyber or authorized	The Responsibility Entity did not review the training program on an annual basis.	The Responsible Entity did document but did not establish, implement, nor maintain an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to	The Responsible Entity did not establish, document, implement, nor maintain an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			unescorted physical access to Critical Cyber Assets.		Critical Cyber Assets.	Critical Cyber Assets.
CIP-004-4	R2.1.	This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained prior to their being granted such access except in specified circumstances such as an emergency.	At least one individual but less than 5% of personnel having authorized cyber or unescorted physical access to Critical Cyber Assets, including contractors and service vendors, were not trained prior to their being granted such access except in specified circumstances such as an emergency.	At least 5% but less than 10% of all personnel having authorized cyber or unescorted physical access to Critical Cyber Assets, including contractors and service vendors, were not trained prior to their being granted such access except in specified circumstances such as an emergency.	At least 10% but less than 15% of all personnel having authorized cyber or unescorted physical access to Critical Cyber Assets, including contractors and service vendors, were not trained prior to their being granted such access except in specified circumstances such as an emergency.	15% or more of all personnel having authorized cyber or unescorted physical access to Critical Cyber Assets, including contractors and service vendors, were not trained prior to their being granted such access except in specified circumstances such as an emergency.
CIP-004-4	R2.2.	Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004-4, and include, at a minimum, the following required items appropriate to personnel roles and responsibilities:	N/A	The training does not include one of the minimum topics as detailed in R2.2.1, R2.2.2, R2.2.3, R2.2.4.	The training does not include two of the minimum topics as detailed in R2.2.1, R2.2.2, R2.2.3, R2.2.4.	The training does not include three or more of the minimum topics as detailed in R2.2.1, R2.2.2, R2.2.3, R2.2.4.
CIP-004-4	R2.2.1.	The proper use of Critical Cyber Assets;	N/A	N/A	N/A	N/A

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
CIP-004-4	R2.2.2.	Physical and electronic access controls to Critical Cyber Assets;	N/A	N/A	N/A	N/A
CIP-004-4	R2.2.3.	The proper handling of Critical Cyber Asset information; and,	N/A	N/A	N/A	N/A
CIP-004-4	R2.2.4.	Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.	N/A	N/A	N/A	N/A
CIP-004-4	R2.3.	The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and attendance records.	N/A	N/A	The Responsible Entity did maintain documentation that training is conducted at least annually, but did not include either the date the training was completed or attendance records.	The Responsible Entity did not maintain documentation that training is conducted at least annually, including the date the training was completed or attendance records.
CIP-004-4	R3.	Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access to Critical	N/A	The Responsible Entity has a personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective	The Responsible Entity has a personnel risk assessment program as stated in R3, but conducted the personnel risk assessment pursuant to that program after	The Responsible Entity does not have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Cyber Assets. A personnel risk assessment shall be conducted pursuant to that program prior to such personnel being granted such access except in specified circumstances such as an emergency. The personnel risk assessment program shall at a minimum include:		bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access, but the program is not documented.	such personnel were granted such access except in specified circumstances such as an emergency.	existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access. OR The Responsible Entity did not conduct the personnel risk assessment pursuant to that program for personnel granted such access except in specified circumstances such as an emergency.
CIP-004-4	R3.1.	The Responsible Entity shall ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and seven-year criminal check. The Responsible Entity may conduct more detailed reviews, as permitted by law and subject to existing collective bargaining unit agreements, depending upon the criticality of the position.	N/A	N/A	The Responsible Entity did not ensure that an assessment conducted included an identity verification (e.g., Social Security Number verification in the U.S.) or a seven-year criminal check.	The Responsible Entity did not ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and seven-year criminal check.
CIP-004-4	R3.2.	The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.	N/A	The Responsible Entity did not update each personnel risk assessment at least every seven years after the initial personnel risk assessment but did	The Responsible Entity did not update each personnel risk assessment for cause (when applicable) but did at least updated it every seven years	The Responsible Entity did not update each personnel risk assessment at least every seven years after the initial personnel risk

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				update it for cause when applicable.	after the initial personnel risk assessment.	assessment nor was it updated for cause when applicable.
CIP-004-4	R3.3.	The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and that personnel risk assessments of contractor and service vendor personnel with such access are conducted pursuant to Standard CIP-004-4.	The Responsible Entity did not document the results of personnel risk assessments for at least one individual but less than 5% of all personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, pursuant to Standard CIP-004-4.	The Responsible Entity did not document the results of personnel risk assessments for 5% or more but less than 10% of all personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, pursuant to Standard CIP-004-4.	The Responsible Entity did not document the results of personnel risk assessments for 10% or more but less than 15% of all personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, pursuant to Standard CIP-004-4.	The Responsible Entity did not document the results of personnel risk assessments for 15% or more of all personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, pursuant to Standard CIP-004-4.
CIP-004-4	R4.	Access —The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets.	The Responsible Entity did not maintain complete list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets,	The Responsible Entity did not maintain complete list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets, missing 5% or more but less than 10% of the authorized personnel.	The Responsible Entity did not maintain complete list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets, missing 10% or more	The Responsible Entity did not maintain complete list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets, missing 15% or more

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			missing at least one individual but less than 5% of the authorized personnel.		but less than 15% of the authorized personnel.	of the authorized personnel.
CIP-004-4	R4.1.	The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, or any change in the access rights of such personnel. The Responsible Entity shall ensure access list(s) for contractors and service vendors are properly maintained.	N/A	The Responsible Entity did not review the list(s) of its personnel who have access to Critical Cyber Assets quarterly.	The Responsible Entity did not update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, nor any change in the access rights of such personnel.	The Responsible Entity did not review the list(s) of all personnel who have access to Critical Cyber Assets quarterly, nor update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, nor any change in the access rights of such personnel.
CIP-004-4	R4.2.	The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.	N/A	The Responsible Entity did not revoke access within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.	The Responsible Entity did not revoke access to Critical Cyber Assets within 24 hours for personnel terminated for cause.	The Responsible Entity did not revoke access to Critical Cyber Assets within 24 hours for personnel terminated for cause nor within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.

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CIP-005-3a	R1.	Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s).	N/A	N/A	N/A	The Responsible Entity did not ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. OR The Responsible Entity did not identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s).
CIP-005-3a	R1.1.	Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).	N/A	N/A	N/A	Access points to the Electronic Security Perimeter(s) do not include all externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).
CIP-005-3a	R1.2.	For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.	N/A	N/A	N/A	For one or more dial-up accessible Critical Cyber Assets that use a non-routable protocol, the Responsible Entity did not define an Electronic Security Perimeter for that single access point at

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						the dial-up device.
CIP-005-3a	R1.3.	Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).	N/A	N/A	N/A	At least one end point of a communication link within the Electronic Security Perimeter(s) connecting discrete Electronic Security Perimeters was not considered an access point to the Electronic Security Perimeter.
CIP-005-3a	R1.4.	Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005-3.	N/A	N/A	N/A	One or more noncritical Cyber Asset within a defined Electronic Security Perimeter is not identified. OR Is not protected pursuant to the requirements of Standard CIP-005.
CIP-005-3a	R1.5.	Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP- 003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3 Requirement R3; Standard CIP-007-3 Requirements R1 and R3 through R9; Standard CIP-008-3; and Standard CIP-	N/A	N/A	N/A	A Cyber Asset used in the access control and/or monitoring of the Electronic Security Perimeter(s) was not afforded one (1) or more of the protective measures as specified in Standard CIP-003-3; Standard CIP-004-3

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		009-3.				Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3c Requirements R3; Standard CIP-007-3 Requirements R1 and R3 through R9; Standard CIP-008-3; and Standard CIP-009-3.
CIP-005-3a	R1.6.	The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), all electronic access points to the Electronic Security Perimeter(s) and the Cyber Assets deployed for the access control and monitoring of these access points.	N/A	N/A	N/A	The Responsible Entity did not maintain documentation of one or more of the following: Electronic Security Perimeter(s), interconnected Critical and noncritical Cyber Assets within the Electronic Security Perimeter(s), electronic access points to the Electronic Security Perimeter(s) and Cyber Assets deployed for the access control and monitoring of these access points.
CIP-005-3a	R2.	Electronic Access Controls — The Responsible Entity shall implement and	N/A	N/A	N/A	The Responsible Entity did not

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		document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).				implement or did not document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).
CIP-005-3a	R2.1.	These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.	N/A	N/A	N/A	The processes and mechanisms did not use an access control model that denies access by default, such that explicit access permissions must be specified.
CIP-005-3a	R2.2.	At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and shall document, individually or by specified grouping, the configuration of those ports and services.	N/A	N/A	N/A	At one or more access points to the Electronic Security Perimeter(s), the Responsible Entity enabled ports and services not required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, or did not document, individually or by specified grouping, the configuration of those ports and

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						services.
CIP-005-3a	R2.3.	The Responsible Entity shall implement and maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).	N/A	N/A	N/A	The Responsible Entity did not implement or maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s) where applicable.
CIP-005-3a	R2.4.	Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.	N/A	N/A	N/A	Where external interactive access into the Electronic Security Perimeter has been enabled the Responsible Entity did not implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.
CIP-005-3a	R2.5.	The required documentation shall, at least, identify and describe:	N/A	N/A	N/A	The required documentation for R2 did not include one or more of the elements described in R2.5.1 through R2.5.4.
CIP-005-3a	R2.5.1.	The processes for access request and authorization.	N/A	N/A	N/A	N/A
CIP-005-3a	R2.5.2.	The authentication methods.	N/A	N/A	N/A	N/A
CIP-005-3a	R2.5.3.	The review process for authorization rights, in accordance with Standard CIP-	N/A	N/A	N/A	N/A

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		004-3 Requirement R4.				
CIP-005-3a	R2.5.4.	The controls used to secure dial-up accessible connections.	N/A	N/A	N/A	N/A
CIP-005-3a	R2.6. ~~(Retired)~~	Appropriate Use Banner — Where technically feasible, electronic access ~~control devices shall display an~~ appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.	The Responsible Entity did not maintain a document identifying the content of the banner. OR Where technically feasible less than 5% electronic access control devices did not display an appropriate use banner on the user screen upon all interactive access attempts.	Where technically feasible 5% but less than 10% of electronic access control devices did not display an appropriate use banner on the user screen upon all interactive access attempts.	Where technically feasible 10% but less than 15% of electronic access control devices did not display an appropriate use banner on the user screen upon all interactive access attempts.	Where technically feasible, 15% or more electronic access control devices did not display an appropriate use banner on the user screen upon all interactive access attempts.
CIP-005-3a	R3.	Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.	N/A	N/A	N/A	The Responsible Entity did not implement or did not document electronic or manual processes monitoring and logging access points.
CIP-005-3a	R3.1.	For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.	N/A	N/A	N/A	Where technically feasible, the Responsible Entity did not implement or did not document electronic or manual processes for

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						monitoring at one or more access points to dial-up devices.
CIP-005-3a	R3.2.	Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.	N/A	N/A	N/A	Where technically feasible, the Responsible Entity did not implement security monitoring process(es) to detect and alert for attempts at or actual unauthorized accesses. OR The above alerts do not provide for appropriate notification to designated response personnel. OR Where alerting is not technically feasible, the Responsible Entity did not review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.
CIP-005-3a	R4.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The	N/A	N/A	N/A	The Responsible Entity did not perform a Vulnerability Assessment at least

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		vulnerability assessment shall include, at a minimum, the following:				annually for one or more of the access points to the Electronic Security Perimeter(s). OR The vulnerability assessment did not include one (1) or more of the subrequirements R4.1, R4.2, R4.3, R4.4, R4.5.
CIP-005-3a	R4.1.	A document identifying the vulnerability assessment process;	N/A	N/A	N/A	N/A
CIP-005-3a	R4.2.	A review to verify that only ports and services required for operations at these access points are enabled;	N/A	N/A	N/A	N/A
CIP-005-3a	R4.3.	The discovery of all access points to the Electronic Security Perimeter;	N/A	N/A	N/A	N/A
CIP-005-3a	R4.4.	A review of controls for default accounts, passwords, and network management community strings;	N/A	N/A	N/A	N/A
CIP-005-3a	R4.5.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	N/A	N/A	N/A	N/A
CIP-005-3a	R5.	Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005-3.	The Responsible Entity did not review, update, and maintain at least one but less than or equal to	The Responsible Entity did not review, update, and maintain greater than 5% but less than or equal to 10% of the	The Responsible Entity did not review, update, and maintain greater than 10% but less than or equal to 15% of the	The Responsible Entity did not review, update, and maintain greater than 15% of the documentation to support compliance

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			5% of the documentation to support compliance with the requirements of Standard CIP-005.	documentation to support compliance with the requirements of Standard CIP-005.	documentation to support compliance with the requirements of Standard CIP-005.	with the requirements of Standard CIP-005.
CIP-005-3a	R5.1.	The Responsible Entity shall ensure that all documentation required by Standard CIP-005-2 reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005-3 at least annually.	N/A	The Responsible Entity did not provide evidence of an annual review of the documents and procedures referenced in Standard CIP-005.	The Responsible Entity did not document current configurations and processes referenced in Standard CIP-005.	The Responsible Entity did not document current configurations and processes and did not review the documents and procedures referenced in Standard CIP-005 at least annually.
CIP-005-3a	R5.2.	The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	N/A	N/A	N/A	The Responsible Entity did not update documentation to reflect a modification of the network or controls within ninety calendar days of the change.
CIP-005-3a	R5.3.	The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-3.	The Responsible Entity retained electronic access logs for 75 or more calendar days, but for less than 90 calendar days.	The Responsible Entity retained electronic access logs for 60 or more calendar days, but for less than 75 calendar days.	The Responsible Entity retained electronic access logs for 45 or more calendar days , but for less than 60 calendar days.	The Responsible Entity retained electronic access logs for less than 45 calendar days.
CIP-005-4a	R1.	Electronic Security Perimeter —The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and	The Responsible Entity did not document one or more access points to the Electronic	The Responsible Entity identified but did not document one or more Electronic Security Perimeter(s).	The Responsible Entity did not ensure that one or more of the Critical Cyber Assets resides within	The Responsible Entity did not ensure that one or more Critical Cyber Assets resides within an

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		document the Electronic Security Perimeter(s) and all access points to the perimeter(s).	Security Perimeter(s).		an Electronic Security Perimeter. OR The Responsible Entity did not identify nor document one or more Electronic Security Perimeter(s).	Electronic Security Perimeter, and the Responsible Entity did not identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s) for all Critical Cyber Assets.
CIP-005-4a	R1.1.	Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).	N/A	N/A	N/A	Access points to the Electronic Security Perimeter(s) do not include all externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).
CIP-005-4a	R1.2.	For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.	N/A	N/A	N/A	For one or more dial-up accessible Critical Cyber Assets that use a non-routable protocol, the Responsible Entity did not define an Electronic Security Perimeter for that single access point at the dial-up device.
CIP-005-4a	R1.3.	Communication links connecting	N/A	N/A	N/A	At least one end point

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		discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).				of a communication link within the Electronic Security Perimeter(s) connecting discrete Electronic Security Perimeters was not considered an access point to the Electronic Security Perimeter.
CIP-005-4a	R1.4.	Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005-4a.	N/A	One or more non-critical Cyber Asset within a defined Electronic Security Perimeter is not identified but is protected pursuant to the requirements of Standard CIP-005.	One or more non-critical Cyber Asset within a defined Electronic Security Perimeter is identified but not protected pursuant to the requirements of Standard CIP-005.	One or more non-critical Cyber Asset within a defined Electronic Security Perimeter is not identified and is not protected pursuant to the requirements of Standard CIP-005.
CIP-005-4a	R1.5.	Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP-003-4; Standard CIP-004-4 Requirement R3; Standard CIP-005-4a Requirements R2 and R3; Standard CIP-006-4c Requirement R3; Standard CIP-007-4 Requirements R1 and R3 through R9; Standard CIP-008-4; and Standard CIP-009-4.	A Cyber Asset used in the access control and/or monitoring of the Electronic Security Perimeter(s) is provided with all but one (1) of the protective measures as specified in Standard CIP-003-4; Standard CIP-004-4 Requirement	A Cyber Asset used in the access control and/or monitoring of the Electronic Security Perimeter(s) is provided with all but two (2) of the protective measures as specified in Standard CIP-003-4; Standard CIP-004-4 Requirement R3; Standard CIP-005-4	A Cyber Asset used in the access control and/or monitoring of the Electronic Security Perimeter(s) is provided with all but three (3) of the protective measures as specified in Standard CIP-003-4; Standard CIP-004-4 Requirement R3; Standard CIP-005-4	A Cyber Asset used in the access control and/or monitoring of the Electronic Security Perimeter(s) is provided without four (4) or more of the protective measures as specified in Standard CIP-003-4; Standard CIP-004-4 Requirement R3; Standard CIP-

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			R3; Standard CIP-005-4 Requirements R2 and R3; Standard CIP-006-4 Requirement R3; Standard CIP-007-4 Requirements R1 and R3 through R9; Standard CIP-008-4; and Standard CIP-009-4.	Requirements R2 and R3; Standard CIP-006-4 Requirement R3; Standard CIP-007-4 Requirements R1 and R3 through R9; Standard CIP-008-4; and Standard CIP-009-4.	Requirements R2 and R3; Standard CIP-006-4 Requirement R3; Standard CIP-007-4 Requirements R1 and R3 through R9; Standard CIP-008-4; and Standard CIP-009-4.	005-4 Requirements R2 and R3; Standard CIP-006-4 Requirement R3; Standard CIP-007-4 Requirements R1 and R3 through R9; Standard CIP-008-4; and Standard CIP-009-4.
CIP-005-4a	R1.6.	The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), all electronic access points to the Electronic Security Perimeter(s) and the Cyber Assets deployed for the access control and monitoring of these access points.	N/A	N/A	The Responsible Entity did not maintain documentation of one of the following: Electronic Security Perimeter(s), interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), electronic access point to the Electronic Security Perimeter(s) or Cyber Asset deployed for the access control and monitoring of these access points.	The Responsible Entity did not maintain documentation of two or more of the following: Electronic Security Perimeter(s), interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), electronic access points to the Electronic Security Perimeter(s) and Cyber Assets deployed for the access control and monitoring of these access points.

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CIP-005-4a	R2.	Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).	N/A	The Responsible Entity implemented but did not document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).	The Responsible Entity documented but did not implement the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).	The Responsible Entity did not implement nor document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).
CIP-005-4a	R2.1.	These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.	N/A	N/A	N/A	The processes and mechanisms did not use an access control model that denies access by default, such that explicit access permissions must be specified.
CIP-005-4a	R2.2.	At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and shall document, individually or by specified grouping, the configuration of those ports and services.	N/A	At one or more access points to the Electronic Security Perimeter(s), the Responsible Entity did not document, individually or by specified grouping, the configuration of those ports and services required for operation and for monitoring Cyber Assets within the Electronic Security	At one or more access points to the Electronic Security Perimeter(s), the Responsible Entity enabled ports and services not required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter but did document,	At one or more access points to the Electronic Security Perimeter(s), the Responsible Entity enabled ports and services not required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and did not document,

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				Perimeter.	individually or by specified grouping, the configuration of those ports and services.	individually or by specified grouping, the configuration of those ports and services.
CIP-005-4a	R2.3.	The Responsible Entity shall implement and maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).	N/A	N/A	The Responsible Entity did implement but did not maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s) where applicable.	The Responsible Entity did not implement nor maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s) where applicable.
CIP-005-4a	R2.4.	Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.	N/A	N/A	N/A	Where external interactive access into the Electronic Security Perimeter has been enabled the Responsible Entity did not implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.
CIP-005-4a	R2.5.	The required documentation shall, at least, identify and describe:	The required documentation for R2 did not include one of the elements described in R2.5.1 through	The required documentation for R2 did not include two of the elements described in R2.5.1 through R2.5.4	The required documentation for R2 did not include three of the elements described in R2.5.1 through R2.5.4	The required documentation for R2 did not include any of the elements described in R2.5.1 through R2.5.4

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			R2.5.4			
CIP-005-4a	R2.5.1.	The processes for access request and authorization.	N/A	N/A	N/A	N/A
CIP-005-4a	R2.5.2.	The authentication methods.	N/A	N/A	N/A	N/A
CIP-005-4a	R2.5.3.	The review process for authorization rights, in accordance with Standard CIP-004-4 Requirement R4.	N/A	N/A	N/A	N/A
CIP-005-4a	R2.5.4.	The controls used to secure dial-up accessible connections.	N/A	N/A	N/A	N/A
CIP-005-4a	R2.6. (Retired)	Appropriate Use Banner —Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.	The Responsible Entity did not maintain a document identifying the content of the banner. OR Where technically feasible less than 5% electronic access control devices did not display an	Where technically feasible 5% but less than 10% of electronic access control devices did not display an appropriate use banner on the user screen upon all interactive access attempts.	Where technically feasible 10% but less than 15% of electronic access control devices did not display an appropriate use banner on the user screen upon all interactive access attempts.	Where technically feasible, 15% or more electronic access control devices did not display an appropriate use banner on the user screen upon all interactive access attempts.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			appropriate use banner on the user screen upon all interactive access attempts.			
CIP-005-4a	R3.	Monitoring Electronic Access —The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.	The Responsible Entity did not document the electronic or manual processes for monitoring and logging access to access points. OR The Responsible Entity did not implement electronic or manual processes monitoring and logging at less than 5% of the access points.	The Responsible Entity did not implement electronic or manual processes monitoring and logging at 5% or more but less than 10% of the access points.	The Responsible Entity did not implement electronic or manual processes monitoring and logging at 10% or more but less than 15 % of the access points.	The Responsible Entity did not implement electronic or manual processes monitoring and logging at 15% or more of the access points.
CIP-005-4a	R3.1.	For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.	The Responsible Entity did not document the electronic or manual processes for monitoring access points to dial-up devices. OR Where technically feasible, the Responsible Entity did not implement electronic or	Where technically feasible, the Responsible Entity did not implement electronic or manual processes for monitoring at 5% or more but less than 10% of the access points to dial-up devices.	Where technically feasible, the Responsible Entity did not implement electronic or manual processes for monitoring at 10% or more but less than 15% of the access points to dial-up devices.	Where technically feasible, the Responsible Entity did not implement electronic or manual processes for monitoring at 15% or more of the access points to dial-up devices.

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			manual processes for monitoring at less than 5% of the access points to dial-up devices.			
CIP-005-4a	R3.2.	Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.	N/A	N/A	Where technically feasible, the Responsible Entity implemented security monitoring process(es) to detect and alert for attempts at or actual unauthorized accesses, however the alerts do not provide for appropriate notification to designated response personnel.	Where technically feasible, the Responsible Entity did not implement security monitoring process(es) to detect and alert for attempts at or actual unauthorized accesses. OR Where alerting is not technically feasible, the Responsible Entity did not review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days
CIP-005-4a	R4.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following:	The Responsible Entity did not perform a Vulnerability Assessment at least annually for less than 5% of access points to the Electronic Security Perimeter(s).	The Responsible Entity did not perform a Vulnerability Assessment at least annually for 5% or more but less than 10% of access points to the Electronic Security Perimeter(s).	The Responsible Entity did not perform a Vulnerability Assessment at least annually for 10% or more but less than 15% of access points to the Electronic Security Perimeter(s).	The Responsible Entity did not perform a Vulnerability Assessment at least annually for 15% or more of access points to the Electronic Security Perimeter(s). OR

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						The vulnerability assessment did not include one (1) or more of the subrequirements R 4.1, R4.2, R4.3, R4.4, R4.5.
CIP-005-4a	R4.1.	A document identifying the vulnerability assessment process;	N/A	N/A	N/A	N/A
CIP-005-4a	R4.2.	A review to verify that only ports and services required for operations at these access points are enabled;	N/A	N/A	N/A	N/A
CIP-005-4a	R4.3.	The discovery of all access points to the Electronic Security Perimeter;	N/A	N/A	N/A	N/A
CIP-005-4a	R4.4.	A review of controls for default accounts, passwords, and network management community strings;	N/A	N/A	N/A	N/A
CIP-005-4a	R4.5.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	N/A	N/A	N/A	N/A
CIP-005-4a	R5.	Documentation Review and Maintenance —The Responsible Entity shall review, update, and maintain all documentation to support compliance with the	The Responsible Entity did not review, update, and maintain at	The Responsible Entity did not review, update, and maintain greater than 5% but	The Responsible Entity did not review, update, and maintain greater than 10% but	The Responsible Entity did not review, update, and maintain greater than 15% of

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		requirements of Standard CIP-005-4a.	least one but less than or equal to 5% of the documentation to support compliance with the requirements of Standard CIP-005-4.	less than or equal to 10% of the documentation to support compliance with the requirements of Standard CIP-005-4.	less than or equal to 15% of the documentation to support compliance with the requirements of Standard CIP-005-4.	the documentation to support compliance with the requirements of Standard CIP-005-4.
CIP-005-4a	R5.1.	The Responsible Entity shall ensure that all documentation required by Standard CIP-005-4a reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005-4a at least annually.	N/A	The Responsible Entity did not provide evidence of an annual review of the documents and procedures referenced in Standard CIP-005-4.	The Responsible Entity did not document current configurations and processes referenced in Standard CIP-005-4.	The Responsible Entity did not document current configurations and processes and did not review the documents and procedures referenced in Standard CIP-005-4 at least annually.
CIP-005-4a	R5.2.	The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	For less than 5% of the applicable changes, the Responsible Entity did not update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	For 5% or more but less than 10% of the applicable changes, the Responsible Entity did not update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	For 10% or more but less than 15% of the applicable changes, the Responsible Entity did not update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	For 15% or more of the applicable changes, the Responsible Entity did not update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.
CIP-005-4a	R5.3.	The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable	The Responsible Entity retained electronic access	The Responsible Entity retained electronic access logs	The Responsible Entity retained electronic access logs	The Responsible Entity retained electronic access logs

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		incidents shall be kept in accordance with the requirements of Standard CIP-008-4.	logs for 75 or more calendar days, but for less than 90 calendar days.	for 60 or more calendar days, but for less than 75 calendar days.	for 45 or more calendar days , but for less than 60 calendar days.	for less than 45 calendar days.
CIP-006-3c	R1.	Physical Security Plan — The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior manager or delegate(s) that shall address, at a minimum, the following:	N/A	N/A	The Responsible Entity created a physical security plan but did not gain approval by a senior manager or delegate(s). OR The Responsible Entity created and implemented but did not maintain a physical security plan.	The Responsible Entity did not document, implement, and maintain a physical security plan.
CIP-006-3c	R1.1.	All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.	N/A	N/A	N/A	The Responsible Entity's physical security plan does not include processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. OR Where a completely enclosed ("six-wall")

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						border cannot be established, the Responsible Entity has not deployed or documented alternative measures to control physical access to such Cyber Assets within the Electronic Security Perimeter.
CIP-006-3c	R1.2.	Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.	N/A	N/A	N/A	The Responsible Entity's physical security plan does not identify all access points through each Physical Security Perimeter or does not identify measures to control entry at those access points.
CIP-006-3c	R1.3	Processes, tools, and procedures to monitor physical access to the perimeter(s).	N/A	N/A	N/A	The Responsible Entity's physical security plan does not include processes, tools, and procedures to monitor physical access to the perimeter(s).
CIP-006-3c	R1.4	Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.	N/A	N/A	N/A	The Responsible Entity's physical security plan does not address the appropriate use of physical access controls as described in Requirement R4.

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CIP-006-3c	R1.5	Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-3 Requirement R4.	N/A	N/A	N/A	The Responsible Entity's physical security plan does not address the review of access authorization requests or the revocation of access authorization, in accordance with CIP-004-3 Requirement R4.
CIP-006-3c	R1.6	A visitor control program for visitors (personnel without authorized unescorted access to a Physical Security Perimeter), containing at a minimum the following:	N/A	N/A	N/A	The Responsible Entity did not include or implement a visitor control program in its physical security plan or it does not meet the requirements of continuous escort.
CIP-006-3c	R1.6.1	Logs (manual or automated) to document the entry and exit of visitors, including the date and time, to and from Physical Security Perimeters.	N/A	N/A	N/A	N/A
CIP-006-3c	R1.6.2	Continuous escorted access of visitors within the Physical Security Perimeter	N/A	N/A	N/A	N/A
CIP-006-3c	R1.7	Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the Physical Security Perimeter, physical	N/A	N/A	N/A	The Responsible Entity's physical security plan does not address r updating the physical security plan within thirty calendar days of the

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		access controls, monitoring controls, or logging controls.				completion of a physical security system redesign or within thirty calendar days of the completion of a reconfiguration. OR The plan was not updated within thirty calendar days of the completion of a physical security system redesign or reconfiguration
CIP-006-3c	R1.8	Annual review of the physical security plan.	N/A	N/A	N/A	The Responsible Entity's physical security plan does not address a process for ensuring that the physical security plan is reviewed at least annually.
CIP-006-3c	R2	Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers, shall:	N/A	N/A	N/A	A Cyber Asset that authorizes and/or logs access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						point such as electronic lock control mechanisms and badge readers, was not protected from unauthorized physical access. OR A Cyber Asset that authorizes and/or logs access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers was not afforded the protective measures specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3a

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Requirements R4 and R5; Standard CIP-007-3; Standard CIP-008-3; and Standard CIP-009-3.
CIP-006-3c	R2.1.	Be protected from unauthorized physical access.	N/A	N/A	N/A	N/A
CIP-006-3c	R2.2.	Be afforded the protective measures specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3a Requirements R4 and R5; Standard CIP-007-3; Standard CIP-008-3; and Standard CIP-009-3.	N/A	N/A	N/A	N/A
CIP-006-3c	R3	Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall reside within an identified Physical Security Perimeter.	N/A	N/A	N/A	A Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) does not reside within an identified Physical Security Perimeter.
CIP-006-3c	R4	Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods: • Card Key: A means of electronic access where the	N/A	N/A	N/A	The Responsible Entity has not documented or has not implemented the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week using one or

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another. • Special Locks: These include, but are not limited to, locks with "restricted key" systems, magnetic locks that can be operated remotely, and "man-trap" systems. • Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station. • Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets				more of the following physical access methods: • Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another. • Special Locks: These include, but are not limited to, locks with "restricted key" systems, magnetic locks that can be operated remotely, and "man-trap" systems. • Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station. • Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.
CIP-006-3c	R5	Monitoring Physical Access — The Responsible Entity shall document and	N/A	N/A.	N/A	The Responsible

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		implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008-3. One or more of the following monitoring methods shall be used: • Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response. • Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4.				Entity has not documented or has not implemented the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week using one or more of the following monitoring methods: • Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response. • Human Observation of Access Points: Monitoring of physical access

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						points by authorized personnel as specified in Requirement R4. OR An unauthorized access attempt was not reviewed immediately and handled in accordance with CIP-008-3.
CIP-006-3c	R6	Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent: • Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method. • Video Recording: Electronic capture of video images of		N/A	N/A	The Responsible Entity has not implemented or has not documented the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent: • Computerized Logging: Electronic logs produced by the Responsible Entity's selected access

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		sufficient quality to determine identity. • Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4				control and monitoring method, • Video Recording: Electronic capture of video images of sufficient quality to determine identity, or • Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4. OR The Responsible Entity has not recorded sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week.
CIP-006-3c	R7	Access Log Retention — The responsible entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-3.	N/A	N/A	N/A	The responsible entity did not retain physical access logs for at least ninety calendar days.

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CIP-006-3c	R8	Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly. The program must include, at a minimum, the following:	N/A	N/A	N/A	The Responsible Entity has not implemented a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly. OR The implemented program does not include one or more of the requirements; R8.1, R8.2, and R8.3.
CIP-006-3c	R8.1	Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.	N/A	N/A	N/A	N/A
CIP-006-3c	R8.2	Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.	N/A	N/A	N/A	N/A
CIP-006-3c	R8.3	Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.	N/A	N/A	N/A	N/A
CIP-006-4c	R1.	Physical Security Plan —The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior manager or delegate(s) that shall address, at a minimum, the following:	N/A	N/A	The Responsible Entity created a physical security plan but did not gain approval by a senior manager or delegate(s). OR	The Responsible Entity did not document, implement, and maintain a physical security plan.

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					The Responsible Entity created and implemented but did not maintain a physical security plan.	
CIP-006-4c	R1.1.	All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.	N/A	Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity has deployed but not documented alternative measures to control physical access to such Cyber Assets within the Electronic Security Perimeter.	Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity has not deployed alternative measures to control physical access to such Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity's physical security plan does not include processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. OR Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity has not deployed and documented alternative measures to control physical to such Cyber Assets within the Electronic Security Perimeter.
CIP-006-4c	R1.2.	Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.	N/A	The Responsible Entity's physical security plan includes measures to control entry at access points but does not identify all access points through each Physical	The Responsible Entity's physical security identifies all access points through each Physical Security Perimeter but does not identify measures to control	The Responsible Entity's physical security plan does not identify all access points through each Physical Security Perimeter nor measures to control

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				Security Perimeter.	entry at those access points.	entry at those access points.
CIP-006-4c	R1.3.	Processes, tools, and procedures to monitor physical access to the perimeter(s).	N/A	N/A	N/A	The Responsible Entity's physical security plan does not include processes, tools, and procedures to monitor physical access to the perimeter(s).
CIP-006-4c	R1.4.	Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.	N/A	N/A	N/A	The Responsible Entity's physical security plan does not address the appropriate use of physical access controls as described in Requirement R4.
CIP-006-4c	R1.5.	Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-4 Requirement R4.	N/A	N/A	The Responsible Entity's physical security plan does not address either the process for reviewing access authorization requests or the process for revocation of access authorization, in accordance with CIP-004-4 Requirement R4.	The Responsible Entity's physical security plan does not address the process for reviewing access authorization requests and the process for revocation of access authorization, in accordance with CIP-004-4 Requirement R4.
CIP-006-4c	R1.6.	A visitor control program for visitors (personnel without authorized unescorted	The responsible Entity included a	The responsible Entity included a visitor	The responsible Entity included a	The Responsible Entity did not include

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		access to a Physical Security Perimeter), containing at a minimum the following:	visitor control program in its physical security plan, but either did not log the visitor entrance or did not log the visitor exit from the Physical Security Perimeter.	control program in its physical security plan, but either did not log the visitor or did not log the escort.	visitor control program in its physical security plan, but it does not meet the requirements of continuous escort.	or implement a visitor control program in its physical security plan.
CIP-006-4c	R1.6.1.	Logs (manual or automated) to document the entry and exit of visitors, including the date and time, to and from Physical Security Perimeters.	N/A	N/A	N/A	N/A
CIP-006-4c	R1.6.2.	Continuous escorted access of visitors within the Physical Security Perimeter.	N/A	N/A	N/A	N/A
CIP-006-4c	R1.7.	Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the Physical Security Perimeter, physical access controls, monitoring controls, or logging controls.	N/A	N/A	The Responsible Entity's physical security plan addresses a process for updating the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration but the plan was not updated within thirty calendar days of the completion of a physical security system redesign or	The Responsible Entity's physical security plan does not address a process for updating the physical security plan within thirty calendar days of the completion of a physical security system redesign or reconfiguration.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					reconfiguration.	
CIP-006-4c	R1.8.	Annual review of the physical security plan.	N/A	N/A	N/A	The Responsible Entity's physical Security plan does not address a process for ensuring that the physical security plan is reviewed at least annually.
CIP-006-4c	R2.	Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers, shall:	A Cyber Asset that authorizes and/or logs access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers was provided with all but one (1) of the protective measures specified in Standard CIP-003-4; Standard CIP-004-4 Requirement R3; Standard CIP-005-4 Requirements R2 and R3; Standard CIP-006-4	A Cyber Asset that authorizes and/or logs access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers was provided with all but two (2) of the protective measures specified in Standard CIP-003-4; Standard CIP-004-4 Requirement R3; Standard CIP-005-4 Requirements R2 and R3; Standard CIP-006-4 Requirements R4 and R5; Standard CIP-007-4; Standard CIP-008-4; and Standard CIP-009-4.	A Cyber Asset that authorizes and/or logs access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers was provided with all but three (3) of the protective measures specified in Standard CIP-003-4; Standard CIP-004-4 Requirement R3; Standard CIP-005-4 Requirements R2 and R3; Standard CIP-006-4 Requirements R4 and R5; Standard CIP-007-4; Standard CIP-008-4; and	A Cyber Asset that authorizes and/or logs access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access point such as electronic lock control mechanisms and badge readers, was not protected from unauthorized physical access. OR A Cyber Asset that authorizes and/or logs access to the Physical Security Perimeter(s), exclusive of hardware at the Physical Security Perimeter access

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			Requirements R4 and R5; Standard CIP-007-4; Standard CIP-008-4; and Standard CIP- 009-4.		Standard CIP-009-4.	point such as electronic lock control mechanisms and badge readers was provided without four (4) or more of the protective measures specified in Standard CIP-003-4; Standard CIP-004-4 Requirement R3; Standard CIP-005-4 Requirements R2 and R3; Standard CIP-006-4 Requirements R4 and R5; Standard CIP-007-4; Standard CIP-008-4; and Standard CIP-009-4.
CIP-006-4c	R2.1.	Be protected from unauthorized physical access.	N/A	N/A	N/A	N/A
CIP-006-4c	R2.2.	Be afforded the protective measures specified in Standard CIP-003-4; Standard CIP-004-4 Requirement R3; Standard CIP-005-4a Requirements R2 and R3; Standard CIP-006-4c Requirements R4 and R5; Standard CIP-007-4; Standard CIP-008-4; and Standard CIP-009-4.	N/A	N/A	N/A	N/A
CIP-006-4c	R3.	Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall reside within an identified Physical Security Perimeter.	N/A	N/A	N/A	A Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) did not reside within

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						an identified Physical Security Perimeter.
CIP-006-4c	R4.	Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods: • Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another • Special Locks: These include, but are not limited to, locks with "restricted key" systems, magnetic locks that can be operated remotely, and "man-trap" systems. • Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station. • Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.	N/A	The Responsible Entity has implemented but not documented the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week using one or more of the following physical access methods: • Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another. • Special Locks: These include, but are not limited to, locks with "restricted key" systems, magnetic locks that can be operated remotely, and "man-trap" systems. Security Personnel: Personnel responsible for controlling	The Responsible Entity has documented but not implemented the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week using one or more of the following physical access methods: • Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another. • Special Locks: These include, but are not limited to, locks with "restricted key" systems, magnetic locks that can be operated remotely, and "man-trap" systems. • Security Personnel:	The Responsible Entity has not documented nor implemented the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week using one or more of the following physical access methods: • Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another. • Special Locks: These include, but are not limited to, locks with "restricted key" systems, magnetic locks that can be operated remotely, and "man-trap" systems. • Security Personnel:

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				physical access who may reside on-site or at a monitoring station. • Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.	Personnel responsible for controlling physical access who may reside on-site or at a monitoring station. • Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.	Personnel responsible for controlling physical access who may reside on-site or at a monitoring station. • Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets..
CIP-006-4c	R5.	Monitoring Physical Access —The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008-4. One or more of the following monitoring methods shall be used: • Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response. • Human Observation of Access Points: Monitoring of physical	N/A	The Responsible Entity has implemented but not documented the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week using one or more of the following monitoring methods: • Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to	The Responsible Entity has documented but not implemented the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week using one or more of the following monitoring methods: • Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate	The Responsible Entity has not documented nor implemented the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week using one or more of the following monitoring methods: • Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		access points by authorized personnel as specified in Requirement R4.		personnel responsible for response. • Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4.	notification to personnel responsible for response. • Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4.	notification to personnel responsible for response. • Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R4. OR An unauthorized access attempt was not reviewed immediately and handled in accordance with CIP-008-4.
CIP-006-4c	R6.	Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent: • Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method. • Video Recording: Electronic capture of video images of	The Responsible Entity has implemented but not documented the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent: • Computerized Logging: Electronic logs	The Responsible Entity has implemented the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent: • Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control	The Responsible Entity has documented but not implemented the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent: • Computerized Logging: Electronic logs produced by the Responsible Entity's selected access	The Responsible Entity has not implemented nor documented the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent: • Computerized Logging: Electronic logs produced by the Responsible Entity's selected access

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		sufficient quality to determine identity. • Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4.	produced by the Responsible Entity's selected access control and monitoring method, • Video Recording: Electronic capture of video images of sufficient quality to determine identity, or • Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4, and has provided logging that records sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week.	and monitoring method, • Video Recording: Electronic capture of video images of sufficient quality to determine identity, or • Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4, but has not provided logging that records sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week..	control and monitoring method, • Video Recording: Electronic capture of video images of sufficient quality to determine identity, or • Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4.	control and monitoring method, • Video Recording: Electronic capture of video images of sufficient quality to determine identity, or • Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4.
CIP-006-4c	R7.	Access Log Retention —The Responsible Entity shall retain physical access logs for at least ninety calendar	The Responsible Entity retained physical access	The Responsible Entity retained physical access logs	The Responsible Entity retained physical access logs	The Responsible Entity retained physical access logs

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		days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-4.	logs for 75 or more calendar days, but for less than 90 calendar days.	for 60 or more calendar days, but for less than 75 calendar days.	for 45 or more calendar days, but for less than 60 calendar days.	for less than 45 calendar days.
CIP-006-4c	R8.	Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly. The program must include, at a minimum, the following:	The Responsible Entity has implemented a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly but the program does not include one of the Requirements R8.1, R8.2, and R8.3.	The Responsible Entity has implemented a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly but the program does not include two of the Requirements R8.1, R8.2, and R8.3.	The Responsible Entity has implemented a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly but the program does not include any of the Requirements R8.1, R8.2, and R8.3.	The Responsible Entity has not implemented a maintenance and testing program to ensure that all physical security systems under Requirements R4, R5, and R6 function properly.
CIP-006-4c	R8.1.	Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.	N/A	N/A	N/A	N/A
CIP-006-4c	R8.2.	Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.	N/A	N/A	N/A	N/A
CIP-006-4c	R8.3.	Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.	N/A	N/A	N/A	N/A

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CIP-007-3	R1.	Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007-3, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.	N/A	N/A	N/A	The Responsible Entity did not ensure the prevention of adverse affects described in R1, by not including the required minimum significant changes. OR The Responsible Entity did not address one or more of the following: R1.1, R1.2, R1.3.
CIP-007-3	R1.1.	The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.	N/A	N/A	N/A	N/A
CIP-007-3	R1.2.	The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.	N/A	N/A	N/A	N/A
CIP-007-3	R1.3.	The Responsible Entity shall document test results.	N/A	N/A	N/A	N/A
CIP-007-3	R2.	Ports and Services — The Responsible Entity shall establish, document and implement a process to ensure that only those ports and services required for normal and emergency operations are enabled.	N/A	N/A	N/A	The Responsible Entity did not establish (implement) or did not document a process to ensure that only those ports and services required for normal and emergency operations are enabled.

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CIP-007-3	R2.1.	The Responsible Entity shall enable only those ports and services required for normal and emergency operations.	N/A	N/A	N/A	The Responsible Entity enabled one or more ports or services not required for normal and emergency operations on Cyber Assets inside the Electronic Security Perimeter(s).
CIP-007-3	R2.2.	The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).	N/A	N/A	N/A	The Responsible Entity did not disable one or more other ports or services, including those used for testing purposes, prior to production use for Cyber Assets inside the Electronic Security Perimeter(s).
CIP-007-3	R2.3.	In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.	N/A	N/A	N/A	For cases where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity did not document compensating measure(s) applied to mitigate risk.
CIP-007-3	R3.	Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003-3 Requirement R6, shall establish, document and implement a security patch management program	N/A	N/A	N/A	The Responsible Entity did not establish (implement) or did not document, either separately or as a component of the

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		for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).				documented configuration management process specified in CIP-003-3 Requirement R6, a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).
CIP-007-3	R3.1.	The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the patches or upgrades.	N/A	N/A	N/A	The Responsible Entity did not document the assessment of security patches and security upgrades for applicability as required in Requirement R3 within 30 calendar days after the availability of the patches and upgrades.
CIP-007-3	R3.2.	The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.	N/A	N/A	N/A	The Responsible Entity did not document the implementation of applicable security patches as required in R3.

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						OR Where an applicable patch was not installed, the Responsible Entity did not document the compensating measure(s) applied to mitigate risk.
CIP-007-3	R4.	Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software ("malware") prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic Security Perimeter(s).	N/A	N/A	N/A	The Responsible Entity, where technically feasible, did not use anti-virus software or other malicious software ("malware") prevention tools, on one or more Cyber Assets within the Electronic Security Perimeter(s).
CIP-007-3	R4.1.	The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.	N/A	N/A	N/A	The Responsible Entity did not document the implementation of antivirus and malware prevention tools for cyber assets within the electronic security perimeter. OR The Responsible Entity did not document the implementation of

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						compensating measure(s) applied to mitigate risk exposure where antivirus and malware prevention tools are not installed.
CIP-007-3	R4.2.	The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention "signatures." The process must address testing and installing the signatures.	N/A	N/A	N/A	The Responsible Entity did not document or did not implement a process including addressing testing and installing the signatures for the update of anti-virus and malware prevention "signatures."
CIP-007-3	R5.	Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.	N/A	N/A	N/A	The Responsible Entity did not document or did not implement technical and procedural controls that enforce access authentication of, and accountability for, all user activity.
CIP-007-3	R5.1.	The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to know" with respect to work functions performed.	N/A	N/A	N/A	The Responsible Entity did not ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to

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						know" with respect to work functions performed.
CIP-007-3	R5.1.1.	The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-3 Requirement R5.	N/A	N/A	N/A	One or more user accounts implemented by the Responsible Entity were not implemented as approved by designated personnel.
CIP-007-3	R5.1.2.	The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.	N/A	The Responsible Entity generated logs with sufficient detail to create historical audit trails of individual user account access activity, however the logs do not contain activity for a minimum of 90 days.	The Responsible Entity generated logs with insufficient detail to create historical audit trails of individual user account access activity.	The Responsible Entity did not generate logs of individual user account access activity.
CIP-007-3	R5.1.3.	The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-3 Requirement R5 and Standard CIP-004-3 Requirement R4.	N/A	N/A	N/A	The Responsible Entity did not review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-3 Requirement R5 and Standard CIP-004-3 Requirement R4.
CIP-007-3	R5.2.	The Responsible Entity shall implement a policy to minimize and manage the	N/A	N/A	N/A	The Responsible Entity did not

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.				implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.
CIP-007-3	R5.2.1.	The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.	N/A	N/A	The Responsible Entity's policy did not include the removal, disabling, or renaming of such accounts where possible, however for accounts that must remain enabled, passwords were changed prior to putting any system into service.	For accounts that must remain enabled, the Responsible Entity did not change passwords prior to putting any system into service.
CIP-007-3	R5.2.2.	The Responsible Entity shall identify those individuals with access to shared accounts.	N/A	N/A	N/A	The Responsible Entity did not identify all individuals with access to shared accounts.
CIP-007-3	R5.2.3.	Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).	N/A	N/A	N/A	Where such accounts must be shared, the Responsible Entity has not implemented (one or more components of) a policy for managing the use of such accounts that limits

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						access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).
CIP-007-3	R5.3.	At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:	N/A	N/A	N/A	The Responsible Entity does not require passwords subject to R5.3.1, R5.3.2, R5.3.3. OR Does not use passwords subject to R5.3.1, R5.3.2, R5.3.3.
CIP-007-3	R5.3.1.	Each password shall be a minimum of six characters.	N/A	N/A	N/A	N/A
CIP-007-3	R5.3.2.	Each password shall consist of a combination of alpha, numeric, and “special” characters.	N/A	N/A	N/A	N/A
CIP-007-3	R5.3.3.	Each password shall be changed at least annually, or more frequently based on risk.	N/A	N/A	N/A	N/A
CIP-007-3	R6.	Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible, implement automated tools or organizational process controls to	N/A	N/A	N/A	The Responsible Entity as technically feasible, did not implement automated tools or organizational

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		monitor system events that are related to cyber security.				process controls, to monitor system events that are related to cyber security on one or more of Cyber Assets inside the Electronic Security Perimeter(s).
CIP-007-3	R6.1.	The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.	N/A	N/A	N/A	The Responsible Entity did not implement or did not document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.
CIP-007-3	R6.2.	The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.	N/A	N/A	N/A	The Responsible entity's security monitoring controls do not issue automated or manual alerts for detected Cyber Security Incidents.
CIP-007-3	R6.3.	The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008-3.	N/A	N/A	N/A	The Responsible Entity did not maintain logs of system events related to cyber security, where technically feasible, to support

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						incident response as required in Standard CIP-008.
CIP-007-3	R6.4.	The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.	N/A	N/A	N/A	The Responsible Entity did not retain one or more of the logs specified in Requirement R6 for at least 90 calendar days.
CIP-007-3	R6.5.	The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.	N/A	N/A	N/A	The Responsible Entity did not review logs of system events related to cyber security nor maintain records documenting review of logs.
CIP-007-3	R7.	Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-3.	N/A	N/A	The Responsible Entity established and implemented formal methods, processes, and procedures for redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005- 3 but did not address redeployment as specified in R7.2.	The Responsible Entity did not establish or implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-3. OR

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						The Responsible Entity established formal methods, processes, and procedures for redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-2 but did not address disposal as specified in R7.1. ~~OR~~ ~~The Responsible Entity did not maintain records pertaining to disposal or[3] redeployment as specified in R7.3.~~

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[3] Please note that FERC's January 20, 2011 Order on Version 2 And Version 3 Violation Risk Factors And Violation Severity Levels For Critical Infrastructure Protection Reliability Standards dictated that this should read "…records pertaining to disposal **of** redeployment as specified in R7.3." (Emphasis added) It has come to NERC's attention that it should read "…records pertaining to disposal **or** redeployment as specified in R7.3." (emphasis added) and NERC has made this change accordingly. NERC proposes to remove this footnote from the final approved list of VSLs.

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						(Deleted text retired)
CIP-007-3	R7.1.	Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	N/A	N/A	N/A	N/A
CIP-007-3	R7.2.	Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	N/A	N/A	N/A	N/A
CIP-007-3	R7.3. (Retired)	The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.	N/A	N/A	N/A	N/A
CIP-007-3	R8	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:	N/A	N/A	N/A	The Responsible Entity did not perform a Vulnerability Assessment on one or more Cyber Assets within the Electronic Security Perimeter at least annually. OR The vulnerability assessment did not include one (1) or more of the subrequirements 8.1, 8.2, 8.3, 8.4.
CIP-007-3	R8.1.	A document identifying the vulnerability assessment process;	N/A	N/A	N/A	N/A
CIP-007-3	R8.2.	A review to verify that only ports and services required for operation of the	N/A	N/A	N/A	N/A

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		Cyber Assets within the Electronic Security Perimeter are enabled;				
CIP-007-3	R8.3.	A review of controls for default accounts; and,	N/A	N/A	N/A	N/A
CIP-007-3	R8.4.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	N/A	N/A	N/A	N/A
CIP-007-3	R9	Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007-3 at least annually. Changes resulting from modifications to the systems or controls shall be documented within thirty calendar days of the change being completed.	N/A	N/A	The Responsible Entity did not review and update the documentation specified in Standard CIP-007-3 at least annually. OR The Responsible Entity did not document changes resulting from modifications to the systems or controls within thirty calendar days of the change being completed.	The Responsible Entity did not review and update the documentation specified in Standard CIP-007-3 at least annually and changes resulting from modifications to the systems or controls were not documented within thirty calendar days of the change being completed.
CIP-007-4	R1.	Test Procedures —The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not	N/A	The Responsible Entity did create, implement and maintain the test procedures as required	The Responsible Entity did not create, implement and maintain the test procedures as	The Responsible Entity did not create, implement and maintain the test procedures as

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		adversely affect existing cyber security controls. For purposes of Standard CIP-007-4, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.		in R1.1, but did not document that testing is performed as required in R1.2. OR The Responsible Entity did not document the test results as required in R1.3.	required in R1.1.	required in R1.1, AND The Responsible Entity did not document that testing was performed as required in R1.2 AND The Responsible Entity did not document the test results as required in R1.3.
CIP-007-4	R1.1.	The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.	N/A	N/A	N/A	N/A
CIP-007-4	R1.2.	The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.	N/A	N/A	N/A	N/A
CIP-007-4	R1.3.	The Responsible Entity shall document test results.	N/A	N/A	N/A	N/A
CIP-007-4	R2.	Ports and Services —The Responsible Entity shall establish, document and implement a process to ensure that only those ports and services required for normal and emergency operations are enabled.	N/A	The Responsible Entity established (implemented) but did not document a process to ensure that only those ports and services required for normal and emergency operations are enabled.	The Responsible Entity documented but did not establish (implement) a process to ensure that only those ports and services required for normal and emergency operations are enabled.	The Responsible Entity did not establish (implement) nor document a process to ensure that only those ports and services required for normal and emergency operations are enabled.

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CIP-007-4	R2.1.	The Responsible Entity shall enable only those ports and services required for normal and emergency operations.	The Responsible Entity enabled ports and services not required for normal and emergency operations on at least one but less than 5% of the Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity enabled ports and services not required for normal and emergency operations on 5% or more but less than 10% of the Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity enabled ports and services not required for normal and emergency operations on 10% or more but less than 15% of the Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity enabled ports and services not required for normal and emergency operations on 15% or more of the Cyber Assets inside the Electronic Security Perimeter(s).
CIP-007-4	R2.2.	The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity did not disable other ports and services, including those used for testing purposes, prior to production use for at least one but less than 5% of the Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity did not disable other ports and services, including those used for testing purposes, prior to production use for 5% or more but less than 10% of the Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity did not disable other ports and services, including those used for testing purposes, prior to production use for 10% or more but less than 15% of the Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity did not disable other ports and services, including those used for testing purposes, prior to production use for 15% or more of the Cyber Assets inside the Electronic Security Perimeter(s).
CIP-007-4	R2.3.	In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.	N/A	N/A	N/A	For cases where unused ports and services cannot be disabled due to technical limitations, the Responsible

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Entity did not document compensating measure(s) applied to mitigate risk exposure.
CIP-007-4	R3.	Security Patch Management —The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003-4 Requirement R6, shall establish, document and implement a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	The Responsible Entity established (implemented) and documented, either separately or as a component of the documented configuration management process specified in CIP-003-4 Requirement R6, a security patch management program but did not include one or more of the following: tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	The Responsible Entity established (implemented) but did not document, either separately or as a component of the documented configuration management process specified in CIP-003-4 Requirement R6, a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	The Responsible Entity documented but did not establish (implement), either separately or as a component of the documented configuration management process specified in CIP-003-4 Requirement R6, a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	The Responsible Entity did not establish (implement) nor document, either separately or as a component of the documented configuration management process specified in CIP-003-4 Requirement R6, a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).
CIP-007-4	R3.1.	The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within	The Responsible Entity documented the assessment of	The Responsible Entity documented the assessment of security	The Responsible Entity documented the assessment of	The Responsible Entity documented the assessment of

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		thirty calendar days of availability of the patches or upgrades.	security patches and security upgrades for applicability as required in Requirement R3 in more than 30 but less than 60 calendar days after the availability of the patches and upgrades.	patches and security upgrades for applicability as required in Requirement R3 in 60 or more but less than 90 calendar days after the availability of the patches and upgrades.	security patches and security upgrades for applicability as required in Requirement R3 in 90 or more but less than 120 calendar days after the availability of the patches and upgrades.	security patches and security upgrades for applicability as required in Requirement R3 in 120 calendar days or more after the availability of the patches and upgrades.
CIP-007-4	R3.2.	The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.	N/A	N/A	N/A	The Responsible Entity did not document the implementation of applicable security patches as required in R3. OR Where an applicable patch was not installed, the Responsible Entity did not document the compensating measure(s) applied to mitigate risk exposure.
CIP-007-4	R4.	Malicious Software Prevention —The Responsible Entity shall use anti-virus software and other malicious software ("malware") prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic	The Responsible Entity, as technically feasible, did not use anti-virus software and other malicious software ("malware")	The Responsible Entity, as technically feasible, did not use anti-virus software and other malicious software ("malware") prevention tools, nor implemented	The Responsible Entity, as technically feasible, did not use anti-virus software and other malicious software ("malware") prevention tools, nor implemented	The Responsible Entity, as technically feasible, did not use anti-virus software and other malicious software ("malware") prevention tools, nor implemented

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Security Perimeter(s).	prevention tools, nor implemented compensating measures, on at least one but less than 5% of Cyber Assets within the Electronic Security Perimeter(s).	compensating measures, on at least 5% but less than 10% of Cyber Assets within the Electronic Security Perimeter(s).	compensating measures, on at least 10% but less than 15% of Cyber Assets within the Electronic Security Perimeter(s).	compensating measures, on 15% or more Cyber Assets within the Electronic Security Perimeter(s).
CIP-007-4	R4.1.	The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.	N/A	N/A	N/A	The Responsible Entity did not document the implementation of antivirus and malware prevention tools for cyber assets within the electronic security perimeter. OR The Responsible Entity did not document the implementation of compensating measure(s) applied to mitigate risk exposure where antivirus and malware prevention tools are not installed.
CIP-007-4	R4.2.	The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention "signatures." The process must address testing and installing the signatures.	The Responsible Entity, as technically feasible, documented and implemented a	The Responsible Entity, as technically feasible, did not document but implemented a process, including	The Responsible Entity, as technically feasible, documented but did not implement a process, including addressing	The Responsible Entity, as technically feasible, did not document nor implement a process including addressing

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			process for the update of anti-virus and malware prevention "signatures.", but the process did not address testing and installation of the signatures.	addressing testing and installing the signatures, for the update of anti-virus and malware prevention "signatures."	testing and installing the signatures, for the update of anti-virus and malware prevention "signatures."	testing and installing the signatures for the update of anti-virus and malware prevention "signatures."
CIP-007-4	R5.	Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.	N/A	The Responsible Entity implemented but did not document technical and procedural controls that enforce access authentication of, and accountability for, all user activity.	The Responsible Entity documented but did not implement technical and procedural controls that enforce access authentication of, and accountability for, all user activity.	The Responsible Entity did not document nor implement technical and procedural controls that enforce access authentication of, and accountability for, all user activity.
CIP-007-4	R5.1.	The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to know" with respect to work functions performed.	N/A	N/A	N/A	The Responsible Entity did not ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to know" with respect to work functions performed.
CIP-007-4	R5.1.1.	The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-4 Requirement R5.	At least one user account but less than 1% of user accounts	One (1) % or more of user accounts but less than 3% of user accounts implemented	Three (3) % or more of user accounts but less than 5% of user accounts	Five (5) % or more of user accounts implemented by the Responsible Entity

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			implemented by the Responsible Entity, were not approved by designated personnel.	by the Responsible Entity were not approved by designated personnel.	implemented by the Responsible Entity were not approved by designated personnel.	were not approved by designated personnel.
CIP-007-4	R5.1.2.	The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.	N/A	The Responsible Entity generated logs with sufficient detail to create historical audit trails of individual user account access activity, however the logs do not contain activity for a minimum of 90 days.	The Responsible Entity generated logs with insufficient detail to create historical audit trails of individual user account access activity.	The Responsible Entity did not generate logs of individual user account access activity.
CIP-007-4	R5.1.3.	The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-4 Requirement R5 and Standard CIP-004-4 Requirement R4.	N/A	N/A	N/A	The Responsible Entity did not review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-4 Requirement R5 and Standard CIP-004-4 Requirement R4.
CIP-007-4	R5.2.	The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.	N/A	N/A	N/A	The Responsible Entity did not implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						account privileges including factory default accounts.
CIP-007-4	R5.2.1.	The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.	N/A	N/A	The Responsible Entity's policy did not include the removal, disabling, or renaming of such accounts where possible, however for accounts that must remain enabled, passwords were changed prior to putting any system into service.	For accounts that must remain enabled, the Responsible Entity did not change passwords prior to putting any system into service.
CIP-007-4	R5.2.2.	The Responsible Entity shall identify those individuals with access to shared accounts.	N/A	N/A	N/A	The Responsible Entity did not identify all individuals with access to shared accounts.
CIP-007-4	R5.2.3.	Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).	N/A	Where such accounts must be shared, the Responsible Entity has a policy for managing the use of such accounts, but is missing 1 of the following 3 items: a) limits access to only those with authorization,	Where such accounts must be shared, the Responsible Entity has a policy for managing the use of such accounts, but is missing 2 of the following 3 items: a) limits access to only those with authorization,	Where such accounts must be shared, the Responsible Entity does not have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				b) has an audit trail of the account use (automated or manual), c) has specified steps for securing the account in the event of personnel changes (for example, change in assignment or termination).	b) has an audit trail of the account use (automated or manual), c) has specified steps for securing the account in the event of personnel changes (for example, change in assignment or termination).	manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).
CIP-007-4	R5.3.	At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:	The Responsible Entity requires and uses passwords as technically feasible, but only addresses 2 of the requirements in R5.3.1, R5.3.2., R5.3.3.	The Responsible Entity requires and uses passwords as technically feasible but only addresses 1 of the requirements in R5.3.1, R5.3.2., R5.3.3.	The Responsible Entity requires but does not use passwords as required in R5.3.1, R5.3.2., R5.3.3 and did not demonstrate why it is not technically feasible.	The Responsible Entity does not require nor use passwords as required in R5.3.1, R5.3.2., R5.3.3 and did not demonstrate why it is not technically feasible.
CIP-007-4	R5.3.1.	Each password shall be a minimum of six characters.	N/A	N/A	N/A	N/A
CIP-007-4	R5.3.2.	Each password shall consist of a combination of alpha, numeric, and “special” characters.	N/A	N/A	N/A	N/A
CIP-007-4	R5.3.3.	Each password shall be changed at least annually, or more frequently based on	N/A	N/A	N/A	N/A

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		risk.				
CIP-007-4	R6.	Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible, implement automated tools or organizational process controls to monitor system events that are related to cyber security.	The Responsible Entity, as technically feasible, did not implement automated tools or organizational process controls to monitor system events that are related to cyber security for at least one but less than 5% of Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity, as technically feasible, did not implement automated tools or organizational process controls to monitor system events that are related to cyber security for 5% or more but less than 10% of Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity did not implement automated tools or organizational process controls, as technically feasible, to monitor system events that are related to cyber security for 10% or more but less than 15% of Cyber Assets inside the Electronic Security Perimeter(s).	The Responsible Entity did not implement automated tools or organizational process controls, as technically feasible, to monitor system events that are related to cyber security for 15% or more of Cyber Assets inside the Electronic Security Perimeter(s).
CIP-007-4	R6.1.	The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.	N/A	The Responsible Entity implemented but did not document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity documented but did not implement the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity did not implement nor document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.

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CIP-007-4	R6.2.	The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.	N/A	N/A	N/A	The Responsible entity's security monitoring controls do not issue automated or manual alerts for detected Cyber Security Incidents.
CIP-007-4	R6.3.	The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008-4.	N/A	N/A	N/A	The Responsible Entity did not maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008-4.
CIP-007-4	R6.4.	The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.	The Responsible Entity retained the logs specified in Requirement R6, for at least 60 days, but less than 90 days.	The Responsible Entity retained the logs specified in Requirement R6, for at least 30 days, but less than 60 days.	The Responsible Entity retained the logs specified in Requirement R6, for at least one day, but less than 30 days.	The Responsible Entity did not retain any logs specified in Requirement R6.
CIP-007-4	R6.5.	The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.	N/A	N/A	N/A	The Responsible Entity did not review logs of system events related to cyber security nor maintain records documenting review of logs.

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CIP-007-4	R7.	Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-4.	The Responsible Entity established and implemented formal methods, processes, and procedures for disposal and redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP- 005-4 but did not maintain records as specified in R7.3. (Retired)	The Responsible Entity established and implemented formal methods, processes, and procedures for disposal of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-4 but did not address redeployment as specified in R7.2.	The Responsible Entity established and implemented formal methods, processes, and procedures for redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-4 but did not address disposal as specified in R7.1.	The Responsible Entity did not establish or implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-4.
CIP-007-4	R7.1.	Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	N/A	N/A	N/A	N/A
CIP-007-4	R7.2.	Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	N/A	N/A	N/A	N/A

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CIP-007-4	R7.3. (Retired)	The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.	N/A	N/A	N/A	N/A
CIP-007-4	R8.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:	The Responsible Entity performed at least annually a Vulnerability Assessment that included 95% or more but less than 100% of Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity performed at least annually a Vulnerability Assessment that included 90% or more but less than 95% of Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity performed at least annually a Vulnerability Assessment that included more than 85% but less than 90% of Cyber Assets within the Electronic Security Perimeter.	The Responsible Entity performed at least annually a Vulnerability Assessment for 85% or less of Cyber Assets within the Electronic Security Perimeter. OR The vulnerability assessment did not include one (1) or more of the subrequirements 8.1, 8.2, 8.3, 8.4.
CIP-007-4	R8.1.	A document identifying the vulnerability assessment process;	N/A	N/A	N/A	N/A
CIP-007-4	R8.2.	A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;	N/A	N/A	N/A	N/A
CIP-007-4	R8.3.	A review of controls for default accounts; and,	N/A	N/A	N/A	N/A

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CIP-007-4	R8.4.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	N/A	N/A	N/A	N/A
CIP-007-4	R9.	Documentation Review and Maintenance —The Responsible Entity shall review and update the documentation specified in Standard CIP-007-4 at least annually. Changes resulting from modifications to the systems or controls shall be documented within thirty calendar days of the change being completed.	N/A	N/A	The Responsible Entity did not review and update the documentation specified in Standard CIP-007-4 at least annually. OR The Responsible Entity did not document changes resulting from modifications to the systems or controls within thirty calendar days of the change being completed.	The Responsible Entity did not review and update the documentation specified in Standard CIP-007-4 at least annually nor were changes resulting from modifications to the systems or controls documented within thirty calendar days of the change being completed.
CIP-008-3	R1.	Cyber Security Incident Response Plan — The Responsible Entity shall develop and maintain a Cyber Security Incident response plan and implement the plan in response to Cyber Security Incidents. The Cyber Security Incident response plan shall address, at a minimum, the following:	N/A	N/A	The Responsible Entity has developed a Cyber Security Incident response plan that addresses all of the components required by R1.1 through R1.6 but has not maintained the plan in accordance with those	The Responsible Entity has not developed a Cyber Security Incident response plan that addresses all of the components required by R1.1 through R1.6, or has not implemented the plan in response to a

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					components.	Cyber Security Incident.
CIP-008-3	R1.1.	Procedures to characterize and classify events as reportable Cyber Security Incidents.	N/A	N/A	N/A	N/A
CIP-008-3	R1.2.	Response actions, including roles and responsibilities of Cyber Security Incident response teams, Cyber Security Incident handling procedures, and communication plans.	N/A	N/A	N/A	N/A
CIP-008-3	R1.3.	Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). The Responsible Entity must ensure that all reportable Cyber Security Incidents are reported to the ES-ISAC either directly or through an intermediary.	N/A	N/A	N/A	N/A
CIP-008-3	R1.4.	Process for updating the Cyber Security Incident response plan within thirty calendar days of any changes.	N/A	N/A	N/A	N/A
CIP-008-3	R1.5.	Process for ensuring that the Cyber Security Incident response plan is reviewed at least annually.	N/A	N/A	N/A	N/A
CIP-008-3	R1.6.	Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the Cyber Security Incident response plan can range from a paper drill, to a full operational exercise, to the response to an actual incident.	N/A	N/A	N/A	N/A
CIP-008-3	R2	Cyber Security Incident Documentation — The Responsible Entity shall keep relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for three calendar	N/A	N/A	N/A	The Responsible Entity has not kept relevant documentation related to Cyber

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		years.				Security Incidents reportable per Requirement R1.1 for at least three calendar years.
CIP-008-4	R1.	Cyber Security Incident Response Plan —The Responsible Entity shall develop and maintain a Cyber Security Incident response plan and implement the plan in response to Cyber Security Incidents. The Cyber Security Incident response plan shall address, at a minimum, the following:	N/A	The Responsible Entity has developed but not maintained a Cyber Security Incident response plan.	The Responsible Entity has developed a Cyber Security Incident response plan but the plan does not address one or more of the subrequirements R1.1 through R1.6.	The Responsible Entity has not developed a Cyber Security Incident response plan or has not implemented the plan in response to a Cyber Security Incident.
CIP-008-4	R1.1.	Procedures to characterize and classify events as reportable Cyber Security Incidents.	N/A	N/A	N/A	N/A
CIP-008-4	R1.2.	Response actions, including roles and responsibilities of Cyber Security Incident response teams, Cyber Security Incident handling procedures, and communication plans.	N/A	N/A	N/A	N/A
CIP-008-4	R1.3.	Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). The Responsible Entity must ensure that all reportable Cyber Security Incidents are reported to the ES-ISAC either directly or through an intermediary.	N/A	N/A	N/A	N/A
CIP-008-4	R1.4.	Process for updating the Cyber Security Incident response plan within thirty	N/A	N/A	N/A	N/A

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		calendar days of any changes.				
CIP-008-4	R1.5.	Process for ensuring that the Cyber Security Incident response plan is reviewed at least annually.	N/A	N/A	N/A	N/A
CIP-008-4	R1.6.	Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the Cyber Security Incident response plan can range from a paper drill, to a full operational exercise, to the response to an actual incident.	N/A	N/A	N/A	N/A
CIP-008-4	R2.	Cyber Security Incident Documentation —The Responsible Entity shall keep relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for three calendar years.	The Responsible Entity has kept relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for two but less than three calendar years.	The Responsible Entity has kept relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for less than two calendar years.	The Responsible Entity has kept relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for less than one calendar year.	The Responsible Entity has not kept relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1.
CIP-009-3	R1	Recovery Plans — The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall address at a minimum the following:	N/A	N/A	N/A	The Responsible Entity has not created or has not annually reviewed their recovery plan(s) for Critical Cyber Assets OR has created a plan but did not address one or more of the requirements CIP-

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						009-1 R1.1 and R1.2.
CIP-009-3	R1.1.	Specify the required actions in response to events or conditions of varying duration and severity that would activate the recovery plan(s).	N/A	N/A	N/A	N/A
CIP-009-3	R1.2.	Define the roles and responsibilities of responders.	N/A	N/A	N/A	N/A
CIP-009-3	R2	Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full operational exercise, to recovery from an actual incident.	N/A	N/A	N/A	The Responsible Entity's recovery plan(s) have not been exercised at least annually.
CIP-009-3	R3	Change Control — Recovery plan(s) shall be updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident. Updates shall be communicated to personnel responsible for the activation and implementation of the recovery plan(s) within thirty calendar days of the change being completed.	N/A	N/A	N/A	The Responsible Entity's recovery plan(s) have not been updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident. OR The Responsible Entity's recovery plan(s) have been updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident but the updates were not communicated to

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						personnel responsible for the activation and implementation of the recovery plan(s) within thirty calendar days of the change.
CIP-009-3	R4	Backup and Restore — The recovery plan(s) shall include processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets. For example, backups may include spare electronic components or equipment, written documentation of configuration settings, tape backup, etc.	N/A	N/A	N/A	The Responsible Entity's recovery plan(s) do not include processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets.
CIP-009-3	R5	Testing Backup Media — Information essential to recovery that is stored on backup media shall be tested at least annually to ensure that the information is available. Testing can be completed off site.	N/A	N/A	N/A	The Responsible Entity's information essential to recovery that is stored on backup media has not been tested at least annually to ensure that the information is available.
CIP-009-4	R1.	Recovery Plans —The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall address at a minimum the following:	N/A	The Responsible Entity has not annually reviewed recovery plan(s) for Critical Cyber Assets.	The Responsible Entity has created recovery plan(s) for Critical Cyber Assets but did not address one of the requirements CIP-009-4 R1.1 or R1.2.	The Responsible Entity has not created recovery plan(s) for Critical Cyber Assets that address at a minimum both requirements CIP-009-4 R1.1 and R1.2.
CIP-009-4	R1.1.	Specify the required actions in response to events or conditions of varying duration and severity that would activate	N/A	N/A	N/A	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the recovery plan(s).				
CIP-009-4	R1.2.	Define the roles and responsibilities of responders.	N/A	N/A	N/A	N/A
CIP-009-4	R2.	Exercises —The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full operational exercise, to recovery from an actual incident.	N/A	N/A	N/A	The Responsible Entity's recovery plan(s) have not been exercised at least annually.
CIP-009-4	R3.	Change Control — Recovery plan(s) shall be updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident. Updates shall be communicated to personnel responsible for the activation and implementation of the recovery plan(s) within thirty calendar days of the change being completed.	The Responsible Entity's recovery plan(s) have been updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident but the updates were communicated to personnel responsible for the activation and implementation of the recovery plan(s) in more than 30 but less than or equal to 120 calendar days of the change.	The Responsible Entity's recovery plan(s) have been updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident but the updates were communicated to personnel responsible for the activation and implementation of the recovery plan(s) in more than 120 but less than or equal to 150 calendar days of the change.	The Responsible Entity's recovery plan(s) have been updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident but the updates were communicated to personnel responsible for the activation and implementation of the recovery plan(s) in more than 150 but less than or equal to 180 calendar days of the change.	The Responsible Entity's recovery plan(s) have not been updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident. OR The Responsible Entity's recovery plan(s) have been updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident but the updates were communicated to personnel responsible for the activation and

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						implementation of the recovery plan(s) in more than 180 calendar days of the change.
CIP-009-4	R4.	Backup and Restore —The recovery plan(s) shall include processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets. For example, backups may include spare electronic components or equipment, written documentation of configuration settings, tape backup, etc.	N/A	N/A	N/A	The Responsible Entity's recovery plan(s) do not include processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets.
CIP-009-4	R5.	Testing Backup Media — Information essential to recovery that is stored on backup media shall be tested at least annually to ensure that the information is available. Testing can be completed off site.	N/A	N/A	N/A	The Responsible Entity's information essential to recovery that is stored on backup media has not been tested at least annually to ensure that the information is available.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
COM-001-1.1	R1.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information:	N/A	The responsible entity failed to provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information to one of the groups specified in R1.1, or R1.2, or R1.3	The responsible entity failed to provide adequate and reliable telecommunications facilities for the exchange of Interconnection or operating information to two of the groups specified in R1.1, or R1.2, or R1.3.	The responsible entity failed to provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information to all 3 of the groups specified in R1.1, or R1.2, or R1.3. OR The responsible entity's telecommunications is not redundant or diversely routed as applicable as specified in R1.4
COM-001-1.1	R1.1.	Internally.	N/A	N/A	N/A	N/A
COM-001-1.1	R1.2.	Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.	N/A	N/A	N/A	N/A
COM-001-1.1	R1.3.	With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.	N/A	N/A	N/A	N/A
COM-001-1.1	R1.4.	Where applicable, these facilities shall be redundant and diversely routed.	N/A	N/A	N/A	N/A

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
COM-001-1.1	R2.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.	N/A	The responsible entity failed to give special attention to emergency telecommunications facilities and equipment not used for routine communications.	N/A	The responsible entity failed to manage, alarm, test and/or actively monitor its vital telecommunications facilities.
COM-001-1.1	R3.	Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas.	N/A	N/A	The responsible entity failed to assist in the investigation and recommending of solutions to telecommunications problems within the area and with other areas.	The responsible entity failed to provide a means to coordinate telecommunications among their respective areas including assisting in the investigation and recommending of solutions to telecommunications problems within the area and with other areas.
COM-001-1.1	R4.	Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations.	N/A	N/A	N/A	The responsible entity used a language other than English and failed to have an agreement to do so.
COM-001-	R5.	Each Reliability Coordinator, Transmission Operator, and Balancing	N/A	N/A	N/A	The responsible entity did not have

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
1.1		Authority shall have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.				written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.
COM-001-1.1	R6.	Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001-0, “NERCNet Security Policy.”	The NERCNet User Organization failed to adhere to 5% or less of the requirements listed in Attachment 1-COM-001, , "NERCNet Security Policy".	The NERCNet User Organization failed to adhere to more than 5% up to (and including) 10% of the requirements listed in Attachment 1 - COM-001, "NERCNet Security Policy".	The NERCNet User Organization failed to adhere to more than 10% up to (and including) 15% of the requirements listed in Attachment 1-COM-001 "NERCNet Security Policy".	The NERCNet User Organization failed to more than 15% of the requirements listed in Attachment 1-COM-001, "NERCNet Security Policy".
COM-002-2	R1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition.	N/A	The responsible entity did not have data links with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. OR The responsible entity did not have voice links with appropriate Reliability Coordinators, Balancing Authorities, and	N/A	The responsible entity failed to have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. OR The responsible entity's communications were not staffed and available for addressing real time emergency

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Transmission Operators.		conditions.
COM-002-2	R1.1.	Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated.	N/A	N/A	The responsible entity failed to notify all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding was anticipated.	The responsible entity failed to notify its Reliability Coordinator through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding was anticipated.
COM-002-2	R2.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.	N/A	The responsible entity provided a clear directive in a clear, concise and definitive manner and required the recipient to repeat the directive, but did not acknowledge the recipient was correct in the repeated directive.	The responsible entity provided a clear directive in a clear, concise and definitive manner, but did not require the recipient to repeat the directive.	The responsible entity failed to provide a clear directive in a clear, concise and definitive manner when required.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
EOP-001-0.1b	R1.	Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.	N/A	The Balancing Authority demonstrated the existence of an operating agreement with at least one adjacent Balancing Authority for emergency assistance, but the agreement did not include provision for obtaining emergency assistance from any remote Balancing Authority.	N/A	The Balancing Authority did not demonstrate the existence of any operating agreements with adjacent Balancing Authorities that include provision for emergency assistance with adjacent Balancing Authorities.
EOP-001-0.1b	R2.	The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.	N/A	N/A	The Transmission Operator demonstrated the existence of an emergency load reduction plan for each identified IROL but at least one of the plans will take longer than 30 minutes to implement.	The Transmission Operator failed to demonstrate the existence of an emergency load reduction plan for all identified IROLs.
EOP-001-0.1b	R3.	Each Transmission Operator and Balancing Authority shall:	N/A	N/A	N/A	N/A
EOP-001-0.1b	R3.1.	Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.	N/A	The Transmission Operator or Balancing Authority demonstrated the existence of a set of plans to mitigate operating	The Transmission Operator or Balancing Authority demonstrated the existence of a set of plans to mitigate operating emergencies for insufficient	The Transmission Operator or Balancing Authority failed to demonstrate the existence of a set of plans to mitigate operating emergencies

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				emergencies for insufficient generating capacity and the plans are implemented but the plans are not maintained.	generating capacity but the plans are neither maintained nor implemented.	for insufficient generating capacity.
EOP-001-0.1b	R3.2.	Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.	N/A	The Transmission Operator or Balancing Authority demonstrated the existence of a set of plans to mitigate operating emergencies on the transmission system and the plans are implemented but the plans are not maintained.	The Transmission Operator or Balancing Authority demonstrated the existence of a set of plans to mitigate operating emergencies on the transmission system but the plans are neither maintained nor implemented.	The Transmission Operator or Balancing Authority failed to demonstrate the existence of a set of plans to mitigate operating emergencies on the transmission system.
EOP-001-0.1b	R3.3.	Develop, maintain, and implement a set of plans for load shedding.	N/A	The Transmission Operator or Balancing Authority demonstrated the existence of a set of plans for load shedding and the plans are implemented but the plans are not maintained.	The Transmission Operator or Balancing Authority demonstrated the existence of a set of plans for load shedding but the plans are neither maintained nor implemented.	The Transmission Operator or Balancing Authority failed to demonstrate the existence of a set of plans for load shedding.
EOP-001-0.1b	R3.4.	Develop, maintain, and implement a set of plans for system restoration.	N/A	The Transmission Operator or Balancing Authority demonstrated the existence of a set of plans for system restoration and the	The Transmission Operator or Balancing Authority demonstrated the existence of a set of plans for system restoration but the plans are neither maintained	The Transmission Operator or Balancing Authority failed to demonstrate the existence of a set of plans for system restoration.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				plans are implemented but the plans are not maintained.	nor implemented.	
EOP-001-0.1b	R4.	Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:	The Transmission Operator or Balancing Authority demonstrated the existence of emergency plans that will enable it to mitigate operating emergencies but the plans do not include sub-requirement R4.4.	The Transmission Operator or Balancing Authority demonstrated the existence of emergency plans that will enable it to mitigate operating emergencies but the plans do not include sub-requirement R4.3.	The Transmission Operator or Balancing Authority demonstrated the existence of emergency plans that will enable it to mitigate operating emergencies but the plans do not include either sub-requirement R4.1 or R4.2.	The Transmission Operator or Balancing Authority demonstrated the existence of emergency plans that will enable it to mitigate operating emergencies but the plans are missing two (2) or more of the sub-requirements identified for R4.
EOP-001-0.1b	R4.1.	Communications protocols to be used during emergencies.	N/A	N/A	N/A	N/A
EOP-001-0.1b	R4.2.	A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.	N/A	N/A	N/A	N/A
EOP-001-0.1b	R4.3.	The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.	N/A	N/A	N/A	N/A
EOP-001-0.1b	R4.4.	Staffing levels for the emergency.	N/A	N/A	N/A	N/A
EOP-001-0.1b	R5.	Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan.	The Transmission Operator and Balancing Authority emergency plan has complied with 90% or more of the number of sub-components.	The Transmission Operator and Balancing Authority emergency plan has complied with 70% to 90% of the number of sub-	The Transmission Operator and Balancing Authority emergency plan has complied with between 50% to 70% of the number of sub-components.	The Transmission Operator and Balancing Authority emergency plan has complied with 50% or less of the number of sub-components

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				components.		
EOP-001-0.1b	R6.	The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to provide evidence that it completed an annual review, and updated each of its emergency plans appropriately. OR The Transmission Operator or Balancing Authority failed to provide a copy of one of its updated emergency plans to its Reliability Coordinator, all its neighboring Transmission Operators, and all its neighboring Balancing Authorities.
EOP-001-0.1b	R7.	The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:	The Transmission Operator or Balancing Authority demonstrated that it coordinated its emergency plans with other Transmission Operators and Balancing Authorities as appropriate but the coordination specified in R7.4 was applicable and was not included.	The Transmission Operator or Balancing Authority demonstrated that it coordinated its emergency plans with other Transmission Operators and Balancing Authorities as appropriate but the coordination specified in R7.3 was applicable and	The Transmission Operator or Balancing Authority demonstrated that it coordinated its emergency plans with other Transmission Operators and Balancing Authorities as appropriate but the coordination specified in either R7.1 or R7.2 was applicable and was not included. .	The Transmission Operator or Balancing Authority demonstrated that it coordinated its emergency plans with other Transmission Operators and Balancing Authorities as appropriate but the coordination specified in two (2) or more of the sub-requirements was applicable and was not included.

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				was not included.		
EOP-001-0.1b	R7.1.	The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.	N/A	N/A	N/A	N/A
EOP-001-0.1b	R7.2.	The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.	N/A	N/A	N/A	N/A
EOP-001-0.1b	R7.3.	The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)	N/A	N/A	N/A	N/A
EOP-001-0.1b	R7.4.	The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.	N/A	N/A	N/A	N/A
EOP-002-3.1	R1.	Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.	N/A	N/A	N/A	The Balancing Authority or Reliability Coordinator does not have responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area OR The Balancing Authority or Reliability Coordinator did not exercise its authority

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						to alleviate capacity and energy emergencies.
EOP-002-3.1	R2.	Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan, to reduce risks to the interconnected system.	N/A	N/A	N/A	The Balancing Authority did not implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.
EOP-002-3.1	R3.	A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.	N/A	N/A	The Balancing Authority communicated its current and future system conditions to its Reliability Coordinator but did not communicate to one or more of its neighboring Balancing Authorities.	The Balancing Authority has failed to communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.
EOP-002-3.1	R4.	A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.	N/A	N/A	N/A	The Balancing Authority has failed to perform the necessary actions as required and stated in the requirement.
EOP-002-3.1	R5.	A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to	N/A	N/A	The Balancing Authority used the assistance provided by the Interconnection's frequency bias for more time than needed to implement corrective	The Balancing Authority used the assistance provided by the Interconnection's frequency bias for more time than needed to implement

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.			actions.	corrective actions and unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes.
EOP-002-3.1	R6.	If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:	The Balancing Authority failed to comply with one of the sub-components.	The Balancing Authority failed to comply with 2 of the sub-components.	The Balancing Authority failed to comply with 3 of the sub-components.	The Balancing Authority failed to comply with more than 3 of the sub-components.
EOP-002-3.1	R6.1.	Loading all available generating capacity.	N/A	N/A	N/A	The Balancing Authority did not use all available generating capacity.
EOP-002-3.1	R6.2.	Deploying all available operating reserve	N/A	N/A	N/A	The Balancing Authority did not deploy all of its available operating reserve.
EOP-002-3.1	R6.3.	Interrupting interruptible load and exports.	N/A	N/A	N/A	The Balancing Authority did not interrupt interruptible load and exports.
EOP-002-3.1	R6.4.	Requesting emergency assistance from other Balancing Authorities.	N/A	N/A	N/A	The Balancing Authority did not request emergency assistance from other Balancing Authorities.
EOP-002-3.1	R6.5.	Declaring an Energy Emergency through its	N/A	N/A	N/A	The Balancing

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		Reliability Coordinator; and				Authority did not declare an Energy Emergency through its Reliability Coordinator.
EOP-002-3.1	R6.6.	Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.	N/A	N/A	N/A	The Balancing Authority did not implement one or more of the procedures stated in the requirement.
EOP-002-3.1	R7.	Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:	N/A	N/A	The Balancing Authority has met only one of the two requirements	The Balancing Authority has not met either of the two requirements
EOP-002-3.1	R7.1.	Manually shed firm load without delay to return its ACE to zero; and	N/A	N/A	N/A	The Balancing Authority did not manually shed firm load without delay to return it's ACE to zero.
EOP-002-3.1	R7.2.	Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."	The Balancing Authority's implementation of an Energy Emergency Alert has missed minor program/procedural elements in Attachment 1-EOP-002-0.	N/A	N/A	The Balancing Authority has failed to meet one or more of the requirements of Attachment 1-EOP-002-0.
EOP-002-3.1	R8.	A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in	The Reliability Coordinator's implementation of an Energy Emergency Alert has missed	N/A	N/A	The Reliability Coordinator has failed to meet one or more of the requirements of Attachment 1-EOP-

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.	minor program/procedural elements in Attachment 1-EOP-002-0.			002-0.
EOP-002-3.1	R9.	When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff:	The Reliability Coordinator failed to comply with one (1) of the sub-components.	The Reliability Coordinator failed to comply with two (2) of the sub-components.	The Reliability Coordinator has failed to comply with three (3) of the sub-components.	The Reliability Coordinator has failed to comply with all four (4) of the sub-components.
EOP-002-3.1	R9.1.	The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."	N/A	N/A	N/A	The Load-Serving Entity failed to request its Reliability Coordinator to initiate an Energy Emergency Alert.
EOP-002-3.1	R9.2.	The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.	N/A	N/A	N/A	The Reliability Coordinator has failed to report to NERC as directed in the requirement.
EOP-002-3.1	R9.3.	The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.	N/A	N/A	N/A	The Reliability Coordinator failed to use EEA 1 to forecast the change of the priority of transmission service as directed in the requirement.
EOP-002-3.1	R9.4.	The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to	N/A	N/A	N/A	The Reliability Coordinator failed to use EEA 2 to announce the change

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Priority 7.				of the priority of transmission service as directed in the requirement.
EOP-003-1	R1.	After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed customer load.
EOP-003-1	R2.	Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.	N/A	N/A	N/A	The responsible entity did not establish plans for automatic load shedding as directed by the requirement.
EOP-003-1	R3.	Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.
EOP-003-1	R4.	A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.	N/A	N/A	N/A	The applicable entity did not consider one of the five required elements, as directed by the requirement.
EOP-003-1	R5.	A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to implement load shedding in steps

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.
EOP-003-1	R6.	After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.
EOP-003-1	R7.	The Transmission Operator and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.	The applicable entity did not coordinate automatic load shedding, as directed by the requirement, affecting 5% or less of its automatic actions.	The applicable entity did not coordinate automatic load shedding, as directed by the requirement, affecting between 5 - 10% of its automatic actions.	The applicable entity did not coordinate automatic load shedding, as directed by the requirement, affecting 10-15%, inclusive, of its automatic actions.	The applicable entity did not coordinate automatic load shedding, as directed by the requirement, affecting greater than 15% of its automatic actions.
EOP-003-1	R8.	Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.	N/A	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.	The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load shedding, as directed by the requirement.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
EOP-003-2	R1.	After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed customer load.
EOP-003-2	R2.	Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.	N/A	N/A	N/A	The Transmission Operator did not establish plans for automatic load shedding for undervoltage conditions as directed by the requirement.
EOP-003-2	R3.	Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.
EOP-003-2	R4.	A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels.	N/A	N/A	N/A	The Transmission Operator failed to consider at least one of the three elements voltage level, rate of voltage decay, or power flow levels) listed in the requirement.
EOP-003-2	R5.	A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.				implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.
EOP-003-2	R6.	After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.
EOP-003-2	R7.	The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions.	The Transmission Operator did not coordinate automatic undervoltage load shedding with 5% or less of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 15% of the types of automatic actions described in the Requirement.
EOP-003-2	R8.	Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be	N/A	The responsible entity did not have plans for operator controlled manual load shedding, as	The responsible entity has plans for manual load shedding but did not have the capability to implement the load	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the

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		capable of implementing the load shedding in a timeframe adequate for responding to the emergency.		directed by the requirement.	shedding, as directed by the requirement.	requirement nor had the capability to implement the load shedding, as directed by the requirement.
EOP-004-1	R1. (Retired)	Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.	The Regional Reliability Organization has demonstrated the existence of a regional reporting procedure, but the procedure is missing minor details or minor program/procedural elements.	The Regional Reliability Organization Regional reporting procedure have been is missing one element that would make the procedure meet the requirement.	The Regional Reliability Organization Regional has a regional reporting procedure but the procedure is not current.	The Regional Reliability Organization does not have a regional reporting procedure.
EOP-004-1	R2.	A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities.	The responsible entity failed to promptly analyze 5% or less of its disturbances on the BES.	The responsible entity failed to promptly analyze more than 5% up to (and including) 10% of its disturbances on the BES.	The responsible entity failed to promptly analyze more than 10% up to (and including) 15% of its disturbances on the BES.	The responsible entity failed to promptly analyze more than 15% of its disturbances on the BES.
EOP-004-1	R3.	A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.	N/A	N/A	N/A	The responsible entities failed to provide a preliminary written report as directed by the requirement.
EOP-004-1	R3.1.	The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a	The responsible entity submitted the report as required in R3.1 more than 24 but less than or equal to 36 hours after the disturbance or unusual occurrence,	The responsible entity submitted the report as required in R3.1 more than 36 hours but less than or equal to 48 hours after the disturbance	The responsible entities submitted the report as required in R3.1 more than 48 hours but less than or equal to 72 hours after the disturbance or unusual	The responsible entities submitted the report as required in R3.1 more than 72-hours after the disturbance or unusual occurrence or

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized.	or discovery of the disturbance or unusual occurrence.	or unusual occurrence, or discovery of the disturbance or unusual occurrence.	occurrence, or discovery of the disturbance or unusual occurrence.	discovery of the disturbance or unusual occurrence.
EOP-004-1	R3.2.	Applicable reporting forms are provided in Attachments 022-1 and 022-2.	N/A	N/A	N/A	N/A
EOP-004-1	R3.3.	Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity shall promptly notify its Regional Reliability Organization(s) and NERC, and verbally provide as much information as is available at that time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.	N/A	N/A	N/A	The responsible entity did not provide its Regional Reliability Organization(s) and NERC with verbal notification or updates about a disturbance as specified in R3.3.
EOP-004-1	R3.4.	If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity shall prepare this	The responsible entity submitted the final report no more than 30 days past the 60 day due date; or the final report was missing one of the three elements specified in R3.4.	The responsible entity submitted the final report between 31 days and 60 days inclusive past the 60 day due date. OR The final report was missing two of the	The responsible entity submitted the final report between 61 days and 90 days inclusive past the 60 day due date	The responsible entity failed to submit the final report. OR The responsible entity submitted the final report 91 days or more past the 60 day due date

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.		three elements specified in R3.4.		OR The responsible entity submitted a final report that was missing all three of the elements specified in R3.4.
EOP-004-1	R4.	When a Bulk Electric System disturbance occurs, the Regional Reliability Organization shall make its representatives on the NERC Operating Committee and Disturbance Analysis Working Group available to the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity immediately affected by the disturbance for the purpose of providing any needed assistance in the investigation and to assist in the preparation of a final report.	N/A	N/A	N/A	The RRO did not make its representatives on the NERC Operating Committee and Disturbance Analysis Working Group available for the purpose of providing any needed assistance in the investigation and to assist in the preparation of a final report.
EOP-004-1	R5.	The Regional Reliability Organization shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if Regional Reliability Organization tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Reliability Organization shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Reliability Organization has taken to accelerate implementation.	The Regional Reliability Organization reviewed all final report recommendations less than twice a year.	The Regional Reliability Organization reviewed 75% or more final report recommendations twice a year.	The Regional Reliability Organization has not reported on any recommendation has not been acted on within two years to the NERC Planning and Operating Committees.	The Regional Reliability Organization has not reviewed the final report recommendations or did not notify the NERC Planning and Operating Committees.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
EOP-005-1	R1.	Each Transmission Operator shall have a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. Each Transmission Operator shall include the applicable elements listed in Attachment 1-EOP-005 in developing a restoration plan.	The responsible entity has a restoration plan that includes 75 % or more but less than 100% of the applicable elements listed in Attachment 1.	The responsible entity has a restoration plan that includes 50% to 75% of the applicable elements listed in Attachment 1.	The responsible entity has a restoration plan that includes 25% - 50% of the applicable elements listed in Attachment 1.	The responsible entity has a restoration plan that includes less than 25% of the applicable elements listed in Attachment 1 OR the responsible entity has no restoration plan.
EOP-005-1	R2.	Each Transmission Operator shall review and update its restoration plan at least annually and whenever it makes changes in the power system network, and shall correct deficiencies found during the simulated restoration exercises.	The Transmission Operator failed to review or update its restoration plan when it made changes in the power system network.	The Transmission Operator failed to review and update its restoration plan at least annually.	The Transmission Operator failed to review and update its restoration plan at least annually or whenever it made changes in the power system network, and failed to correct deficiencies found during the simulated restoration exercises.	The Transmission Operator failed to review and update its restoration plan at least annually and whenever it made changes in the power system network, and failed to correct deficiencies found during the simulated restoration exercises.
EOP-005-1	R3.	Each Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection.	N/A	N/A	N/A	The Transmission Operator's restoration plans failed to make restoration of the integrity of the Interconnection a priority.
EOP-005-1	R4.	Each Transmission Operator shall coordinate its restoration plans with the Generator Owners and Balancing Authorities within its area, its Reliability Coordinator, and neighboring Transmission Operators and Balancing Authorities.	The Transmission Operator failed to coordinate its restoration plans with 5% or less of the entities identified in the requirement.	The Transmission Operator failed to coordinate its restoration plans with more than 5% up to (and including) 10% of the entities identified in the	The Transmission Operator failed to coordinate its restoration plans with more than 10% up to (and including) 15% of the entities identified in	The Transmission Operator failed to coordinate its restoration plans with more than 15% of the entities identified in the requirement.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				requirement.	the requirement.	
EOP-005-1	R5.	Each Transmission Operator and Balancing Authority shall periodically test its telecommunication facilities needed to implement the restoration plan.	N/A	N/A	N/A	The responsible entity failed to periodically test its telecommunication facilities needed to implement the restoration plan.
EOP-005-1	R6.	Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.	The Transmission Operator or Balancing Authority failed to train 5% or less of its operating personnel in the implementation of the restoration plan.	The Transmission Operator or Balancing Authority failed to train more than 5% up to (and including) 10 % of its operating personnel in the implementation of the restoration plan.	The Transmission Operator or Balancing Authority failed to train more than 10 % up to (and including) 15% of its operating personnel in the implementation of the restoration plan.	The Transmission Operator or Balancing Authority failed to train more than 15% of its operating personnel in the implementation of the restoration plan.
EOP-005-1	R7.	Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority did not verify the restoration procedure by actual testing or by simulation.
EOP-005-1	R8.	Each Transmission Operator shall verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan requirements for the Transmission Operator's area.	N/A	N/A	N/A	The Transmission Operator failed to verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						requirements for the Transmission Operator's area.
EOP-005-1	R9.	The Transmission Operator shall document the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started and shall provide this documentation for review by the Regional Reliability Organization upon request. Such documentation may include Cranking Path diagrams.	N/A	N/A	The Transmission Operator documented the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started, but did not provide the documentation as requested by the Regional Reliability Organization.	The Transmission Operator failed to document the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started.
EOP-005-1	R10.	The Transmission Operator shall demonstrate, through simulation or testing, that the blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.	For less than 25% of the blackstart generating units in its restoration plan, the Transmission Operator failed to demonstrate, through simulation or testing, that these blackstart generating units can perform their intended functions as required in the regional restoration plan.	For 25% or more, but less than 50% of the blackstart generating units in its restoration plan, the Transmission Operator failed to demonstrate, through simulation or testing, that these blackstart generating units can perform their intended functions as required in the regional restoration plan.	For 50% or more, but less than 75% of the blackstart generating units in its restoration plan, the Transmission Operator failed to demonstrate, through simulation or testing, that these blackstart generating units can perform their intended functions as required in the regional restoration plan.	For 75% or more of the blackstart generating units in its restoration plan, the Transmission Operator failed to demonstrate, through simulation or testing, that these blackstart generating units can perform their intended functions as required in the regional restoration plan.
EOP-005-1	R10.1.	The Transmission Operator shall perform this simulation or testing at least once every five years.	N/A	N/A	N/A	The Transmission Operator failed to perform the required simulation or testing at least once every five years.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
EOP-005-1	R11.	Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the Bulk Electric System to normal.	The responsible entity failed to comply with less than 25% of the number of sub-components.	The responsible entity failed to comply with 25% or more and less than 50% of the number of sub-components.	The responsible entity failed to comply with 50% or more and less than 75% of the number of sub-components.	The responsible entity failed to comply with more than 75% of the number of sub-components.
EOP-005-1	R11.1.	The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent and condition of the isolated area(s).	N/A	N/A	N/A	The responsible entity failed to work in conjunction with their Reliability Coordinator to determine the extent and condition of the isolated area(s)
EOP-005-1	R11.2.	The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including adjusting generation, placing additional generators on line, or load shedding.	N/A	N/A	N/A	The affected Transmission Operators and Balancing Authorities failed to take the necessary actions to restore Bulk Electric System frequency to normal.
EOP-005-1	R11.3.	The affected Balancing Authorities, working with their Reliability Coordinator(s), shall immediately review the Interchange Schedules between those Balancing Authority Areas or fragments of those Balancing Authority Areas within the separated area and make adjustments as needed to facilitate the restoration. The affected Balancing Authorities shall make all attempts to maintain the adjusted Interchange Schedules, whether generation control is manual or automatic.	N/A	N/A	The responsible entity failed to make all attempts to maintain adjusted Interchange Schedules as required in R11.3	The responsible entity failed to immediately review the Interchange Schedules between those Balancing Authority Areas or fragments of those Balancing Authority Areas within the separated area and make adjustments to facilitate the restoration as required

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						in R11.3.
EOP-005-1	R11.4.	The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.	N/A	N/A	N/A	The affected Transmission Operators failed to give high priority to restoration of off-site power to nuclear stations.
EOP-005-1	R11.5.	The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:	N/A	N/A	N/A	The Transmission Operator attempted to resynchronize an isolated area(s) with a surrounding area(s) when one (1) or more of the sub-requirements of R11.5 were not met.
EOP-005-1	R11.5.1.	Voltage, frequency, and phase angle permit.	N/A	N/A	N/A	N/A
EOP-005-1	R11.5.2.	The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across the system are considered.	N/A	N/A	N/A	N/A
EOP-005-1	R11.5.3.	Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.	N/A	N/A	N/A	N/A
EOP-005-1	R11.5.4.	Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.	N/A	N/A	N/A	N/A
EOP-006-1	R1.	Each Reliability Coordinator shall be aware of the restoration plan of each Transmission Operator in its Reliability Coordinator Area in accordance with NERC and regional requirements.	The Reliability Coordinator is not aware of 5% or less of its Transmission Operators' restoration plans.	The Reliability Coordinator is not aware of more than 5% up to (and including) 10% of its Transmission Operators'	The Reliability Coordinator is not aware of more than 10% up to (and including) 15% of its Transmission Operators' restoration	The Reliability Coordinator is not aware of more than 15% of its Transmission Operators' restoration

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				restoration plans.	plans.	plans.
EOP-006-1	R2.	The Reliability Coordinator shall monitor restoration progress and coordinate any needed assistance.	N/A	N/A	The Reliability Coordinator failed to monitor restoration progress or failed to coordinate assistance.	The Reliability Coordinator failed to monitor restoration progress and failed to coordinate assistance.
EOP-006-1	R3.	The Reliability Coordinator shall have a Reliability Coordinator Area restoration plan that provides coordination between individual Transmission Operator restoration plans and that ensures reliability is maintained during system restoration events.	N/A	The Reliability Coordinator's Reliability Coordinator Area restoration plan did not provide coordination between less than 10% of its individual Transmission Operator restoration plans.	The Reliability Coordinator's Reliability Coordinator Area restoration plan did not provide coordination between 10% or more of the Transmission Operator restoration plans.	The Reliability Coordinator does not have a Reliability Coordinator Area restoration plan. OR The Reliability Coordinator's Reliability Coordinator Area restoration plan does not ensure reliability is maintained during system restoration events.
EOP-006-1	R4.	The Reliability Coordinator shall serve as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators and Transmission Operators or Balancing Authorities not immediately involved in restoration.	N/A	N/A	N/A	The Reliability Coordinator failed to serve as primary contact for disseminating information regarding restoration in accordance with Requirement R4.
EOP-006-1	R5.	Reliability Coordinators shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points so as not to cause a Burden on adjacent Transmission Operator, Balancing Authority, or Reliability	N/A	N/A	N/A	The Reliability Coordinator failed to approve, communicate, and coordinate the re-synchronizing of

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		Coordinator Areas.				major system islands or synchronizing points as stated in Requirement R5.
EOP-006-1	R6.	The Reliability Coordinator shall take actions to restore normal operations once an operating emergency has been mitigated in accordance with its restoration plan.	N/A	N/A	N/A	The Reliability Coordinator failed to take actions to restore normal operations once an operating emergency was mitigated in accordance with its restoration plan.
EOP-008-0	R1.	Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:	The Reliability Coordinator, Transmission Operator and Balancing Authority failed to comply with one of the sub-requirements.	The Reliability Coordinator, Transmission Operator and Balancing Authority failed to comply with two of the sub-requirements.	The Reliability Coordinator, Transmission Operator and Balancing Authority failed to comply with three or four of the sub-requirements.	The Reliability Coordinator, Transmission Operator and Balancing Authority failed to comply with more than four of the sub-requirements.
EOP-008-0	R1.1.	The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.	The responsible entity's contingency plan relies on data or voice communication from the primary control facility for up to 25% of the functions identified in R1.2 and R1.3.	The responsible entity's contingency plan relies on data or voice communication from the primary control facility for 25% to 50% of the functions identified in R1.2 and R1.3.	The responsible entity's contingency plan relies on data or voice communication from the primary control facility for 50% to 75% of the functions identified in R1.2 and R1.3.	The responsible entity's contingency plan relies on data and voice communication from the primary control facility for more than 75% of the functions identified in R1.2 and R1.3.
EOP-008-0	R1.2.	The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.	N/A	N/A	N/A	The responsible entity's plan failed to include procedures and responsibilities for providing basic tie line control and

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.
EOP-008-0	R1.3.	The contingency plan must address monitoring and control of critical transmission facilities, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. The plan shall list the critical facilities.	The responsible entity's contingency plan failed to address one of the elements listed in the requirement.	The responsible entity's contingency plan failed to address two of the elements listed in the requirement.	The responsible entity's contingency plan failed to address three of the elements listed in the requirement.	The responsible entity's contingency plan failed to address four or more of the elements listed in the requirement.
EOP-008-0	R1.4.	The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.	N/A	N/A	N/A	The responsible entity's plan failed to include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.
EOP-008-0	R1.5.	The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.	N/A	N/A	N/A	The responsible entity's plan failed to include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.
EOP-008-0	R1.6.	The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the contingency plans.	N/A	N/A	N/A	The responsible entity's plan failed to include procedures and responsibilities for providing annual training to ensure that operating personnel

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						are able to implement the contingency plans.
EOP-008-0	R1.7.	The plan shall be reviewed and updated annually.	The responsible entity's plan was reviewed within 3 months of passing its annual review date.	The responsible entity's plan was reviewed within 6 months of passing its annual review date.	The responsible entity's plan was reviewed within 9 months of passing its annual review date.	The responsible entity's plan was reviewed more than 9 months of passing its annual review date.
EOP-008-0	R1.8.	Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.	N/A	N/A	N/A	The responsible entity failed to make interim provisions when it is took more than one hour to implement the contingency plan for loss of primary control facility.
EOP-009-0	R1.	The Generator Operator of each blackstart generating unit shall test the startup and operation of each system blackstart generating unit identified in the BCP as required in the Regional BCP (Reliability Standard EOP-007-0_R1). Testing records shall include the dates of the tests, the duration of the tests, and an indication of whether the tests met Regional BCP requirements.	The Generator Operator Blackstart unit testing and recording is missing minor program/procedural elements.	Startup and testing of each Blackstart unit was performed, but the testing records are incomplete. The testing records are missing 25% or less of data requested in the requirement'.	The Generator Operator's failed to test 25% or less of the Blackstart units or testing records are incomplete. The testing records are missing between 25% and 50% of data requested in the requirement.	The Generator Operator failed to test more than 25% of its Blackstart units or does not have Blackstart testing records or is missing more than 50% of the required data.
EOP-009-0	R2.	The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating unit to the Regional Reliability Organizations and upon request to NERC.	N/A	N/A	N/A	The Generator Owner or Generator Operator did not provide the required blackstart documentation to its Regional Reliability Organization or upon request to NERC.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-001-0	R1.	The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Reliability Organization, subregional, Power Pool, and individual Transmission Owner planning criteria and facility connection requirements. The Transmission Owner's facility connection requirements shall address connection requirements for:	Not Applicable.	The Transmission Owner failed to do one of the following: Document or maintain or publish facility connection requirements as specified in the Requirement OR Failed to include one (1) of the components and specified in R1.1, R1.2 or R1.3.	The Transmission Owner failed to do one of the following: Document or maintain or publish its facility connection requirements as specified in the Requirement. OR Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3 OR Failed to document or maintain or publish its facility connection requirements as specified in the Requirement **and** failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3	The Transmission Owner did not develop facility connection requirements
FAC-001-0	R1.1.	Generation facilities,	N/A	N/A	N/A	N/A
FAC-001-0	R1.2.	Transmission facilities, and	N/A	N/A	N/A	N/A
FAC-001-0	R1.3.	End-user facilities	N/A	N/A	N/A	N/A

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-001-0	R2.	The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:	The Transmission Owner's facility connection requirements do not address one to four of the sub-components. (R2.1.1 to R2.1.16)	The Transmission Owner's facility connection requirements do not address five to eight of the sub-components. (R2.1.1 to R2.1.16)	The Transmission Owner's facility connection requirements do not address nine to twelve of the sub-components. (R2.1.1 to R2.1.16)	The Transmission Owner's facility connection requirements do not address thirteen or more of the sub-components. (R2.1.1 to R2.1.16)
FAC-001-0	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	The Transmission Owner's facility connection requirements do not address one to four of the sub-components. (R2.1.1 to R2.1.16)	The Transmission Owner's facility connection requirements do not address five to eight of the sub-components. (R2.1.1 to R2.1.16)	The Transmission Owner's facility connection requirements do not address nine to twelve of the sub-components. (R2.1.1 to R2.1.16)	The Transmission Owner's facility connection requirements do not address thirteen or more of the sub-components. (R2.1.1 to R2.1.16)
FAC-001-0	R2.1.1.	Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.2.	Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-001-0	R2.1.3.	Voltage level and MW and MVAR capacity or demand at point of connection.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.4.	Breaker duty and surge protection.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.5.	System protection and coordination.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.6.	Metering and telecommunications.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.7.	Grounding and safety issues.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.8.	Insulation and insulation coordination.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.9.	Voltage, Reactive Power, and power factor control.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.10.	Power quality impacts.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new

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						facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.11.	Equipment Ratings.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.12.	Synchronizing of facilities.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.13.	Maintenance coordination.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.14.	Operational issues (abnormal frequency and	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		voltages).				owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.15.	Inspection requirements for existing or new facilities.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R2.1.16.	Communications and procedures during normal and emergency operating conditions.	Not Applicable.	Not Applicable.	Not Applicable.	The Transmission owner's procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems failed to include this subrequirement.
FAC-001-0	R3.	The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional Reliability Organization, and NERC on request (five business days).	The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.	The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.	The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.	The responsible entity made the requirements available more than 30 business days after a request.

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FAC-002-1	R1.	The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:	The Responsible Entity failed to include in their assessment one of the subrequirements.	The Responsible Entity failed to include in their assessment two of the subrequirements.	The Responsible Entity failed to include in their assessment three of the subrequirements.	The Responsible Entity failed to include in their assessment four or more of the subrequirements.
FAC-002-1	R1.1.	Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.	Not Applicable.	Not Applicable.	Not Applicable.	The responsible entity's assessment did not include the evaluation.
FAC-002-1	R1.2.	Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.	Not Applicable.	Not Applicable.	Not Applicable.	The responsible entity’s assessment did not include the ensurance of compliance.
FAC-002-1	R1.3.	Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.	Not Applicable.	Not Applicable.	Not Applicable.	The responsible entity’s assessment did not include the evidence of coordination.
FAC-002-1	R1.4.	Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under both normal and contingency conditions in accordance with Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.	Not Applicable.	Not Applicable.	Not Applicable.	The responsible entity's assessment did not include the evidence of the studies.
FAC-002-1	R1.5.	Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly	Not Applicable.	Not Applicable.	Not Applicable.	The responsible entity's assessment did not include the

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		coordinated recommendations.				documentation.
FAC-002-1	R2. (Retired)	The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) and NERC on request (within 30 calendar days).	The responsible entity provided the documentation more than 30 calendar days, but not more than 45 calendar days, after a request.	The responsible entity provided the documentation more than 45 calendar days, but not more than 60 calendar days, after a request.	The responsible entity provided the documentation more than 60 calendar days, but not more than 120 calendar days, after a request.	The responsible entity provided the documentation more than 120 calendar days after a request or was unable to provide the documentation.
FAC-003-1	R1.	The Transmission owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work Specifications. 1. ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.	The responsible entity did not include and keep current one of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current two of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current three of the four required elements of its TVMP, as directed by the requirement.	The responsible entity did not include and keep current all required elements of the TVMP, as directed by the requirement.
FAC-003-1	R1.1.	The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines.	N/A	N/A	The applicable entity TVMP did not define a schedule, as directed by the requirement, or the type of ROW vegetation inspections, as directed by the requirement.	The applicable entity TVMP did not define a schedule, as directed by the requirement, nor the type of ROW vegetation inspections, as directed by the requirement.
FAC-003-1	R1.2.	The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into	N/A	N/A	N/A	The responsible entity, in its TVMP, failed to identify and document clearances between

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.				vegetation and any overhead, ungrounded supply conductors. OR The responsible entity, in its TVMP, failed to take into consideration transmission line voltage, or the effects of ambient temperature on conductor sag under maximum design loading, or the effects of wind velocities on conductor sway. OR The responsible entity, in its TVMP, failed to establish Clearance 1 or Clearance 2 values.
FAC-003-1	R1.2.1.	Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location	N/A	N/A	N/A	The responsible entity failed to determine and document an appropriate clearance distance to be achieved at the time of transmission vegetation management work taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.				management work. OR The responsible entity documented a Clearance 1 value that was smaller than its Clearance 2 value.
FAC-003-1	R1.2.2.	Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.	N/A	N/A	N/A	The responsible entity failed to determine and document Clearance 2 values taking into account local conditions and the expected time frame in which the responsible entity expects to return for future vegetation management work.
FAC-003-1	R1.2.2.1.	Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.	N/A	N/A	N/A	Where transmission system transient overvoltage factors were not known, clearances were not derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

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FAC-003-1	R1.2.2.2.	Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.	Not Applicable.	Not Applicable.	Not Applicable.	Where transmission system transient overvoltage factors are known, clearances were not derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.
FAC-003-1	R1.3.	All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, one of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, 5% or less of those persons did not hold appropriate qualifications and training to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, two of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 5% up to (and including) 10%of those persons did not hold appropriate qualifications and training to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 10% up to (and including) 15%of those persons did not hold appropriate qualifications and training to perform their duties.	For responsible entities directly involving fewer than 20 persons in the design and implementation of the TVMP, more than three of those persons did not hold appropriate qualifications and training to perform their duties. For responsible entities directly involving 20 or more persons in the design and implementation of the TVMP, more than 15% of those persons did not hold appropriate qualifications and training to perform their duties.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
FAC-003-1	R1.4.	Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.	N/A	N/A	N/A	The responsible entity's TVMP does not include mitigation measures to achieve sufficient clearances where restrictions to the ROW are in effect.
FAC-003-1	R1.5.	Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.	N/A	N/A	N/A	The responsible entity did not establish or did not document a process for the immediate communication of vegetation conditions that present an imminent threat of line outage, as directed by the requirement.
FAC-003-1	R2.	The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking	The responsible entity did not meet one of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the	The responsible entity did not meet two of the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan)	The responsible entity did not meet the three required elements (including in the annual plan a description of methods used for vegetation management, maintaining documentation of adjustments to the annual plan, or having systems and procedures for tracking work performed as part of the annual plan) specified in the requirement.	The responsible entity does not have an annual plan for vegetation management. OR The responsible entity has not implemented the annual plan for vegetation management.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.	requirement.	specified in the requirement.		
FAC-003-1	R3.	The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.	The responsible entity failed to provide a quarterly outage report, but did not experience any reportable outages. OR The responsible entity provided a quarterly report, but failed to report in the manner specified by one or more of the following subcomponents of R3: R3.1 or R3.2.	The responsible entity provided a quarterly report, but failed to include information required by R3.3.	The responsible entity provided a quarterly outage report, but failed to include a reportable Category 3 outage as described in R3.4.3.	The responsible entity experienced reportable outages but failed to provide a quarterly report. OR The responsible entity provided a quarterly outage report, but failed to include a reportable Category 1 (as described in R3.4.1) or Category 2 outage (as described in R3.4.2).
FAC-003-1	R3.1.	Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.	N/A	N/A	N/A	N/A
FAC-003-1	R3.2.	The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable	N/A	N/A	N/A	N/A

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		regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).				
FAC-003-1	R3.3.	The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.	N/A	N/A	N/A	N/A
FAC-003-1	R3.4.	An outage shall be categorized as one of the following:	N/A	N/A	N/A	N/A
FAC-003-1	R3.4.1.	Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;	N/A	N/A	N/A	N/A
FAC-003-1	R3.4.2.	Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;	N/A	N/A	N/A	N/A
FAC-003-1	R3.4.3.	Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.	N/A	N/A	N/A	N/A
FAC-003-1	R4.	The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions	Not applicable.	Not applicable.	The RRO did not submit a quarterly report to NERC for a	The RRO did not submit a quarterly report to NERC for more than two

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		taken by the RRO as a result of any of the reported outages.			single quarter.	consecutive quarters.
FAC-008-1	R1.	The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities. The methodology shall include all of the following:	The responsible entity failed to include in their methodology one of the subcomponents of R1.3, (R1.3.1 to R1.3.5).	The responsible entity failed to include in their methodology two of the subcomponents of R1.3, (R1.3.1 to R1.3.5).	The responsible entity rating methodology did not address either of the sub-components of R1.2 (R1.2.1 or R1.2.2). OR The responsible entity failed to include in their methodology three of the subcomponents of R1.3, (R1.3.1 to R1.3.5).	The Transmission Owner or Generation Owner does not have a documented Facility Ratings Methodology for use in developing facility ratings. The responsible entity's rating methodology failed to recognize a facility's rating based on the most limiting component rating as required in R1.1. OR The responsible entity rating methodology did not address the components of R1.2, (R1.2.1 and R1.2.2). OR The responsible entity failed to include in their methodology four or more of the subcomponents of R1.3, (R1.3.1 to R1.3.5).
FAC-008-1	R1.1.	A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.	N/A	N/A	N/A	N/A
FAC-008-1	R1.2.	The method by which the Rating (of major BES equipment that comprises a Facility) is	N/A	N/A	N/A	N/A

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		determined.				
FAC-008-1	R1.2.1.	The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.	N/A	N/A	N/A	N/A
FAC-008-1	R1.2.2.	The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.	N/A	N/A	N/A	N/A
FAC-008-1	R1.3.	Consideration of the following:	N/A	N/A	N/A	N/A
FAC-008-1	R1.3.1.	Ratings provided by equipment manufacturers.	N/A	N/A	N/A	N/A
FAC-008-1	R1.3.2.	Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).	N/A	N/A	N/A	N/A
FAC-008-1	R1.3.3.	Ambient conditions.	N/A	N/A	N/A	N/A
FAC-008-1	R1.3.4.	Operating limitations.	N/A	N/A	N/A	N/A
FAC-008-1	R1.3.5.	Other assumptions.	N/A	N/A	N/A	N/A
FAC-008-1	R2. (Retired)	The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.	The responsible entity made the Facility Ratings Methodology available within more than 15 business days but less than or equal to 25 business days after a request.	The responsible entity made the Facility Ratings Methodology available within more than 25 business days but less than or equal to 35 business days after a request.	The responsible entity made the Facility Ratings Methodology available within more than 35 business days but less than or equal to 45 business days after a request.	The responsible entity failed to make available the Facility Ratings Methodology available in more than 45 business days after a request.
FAC-008-1	R3. (Retired)	If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a	The responsible entity provided a response in more than 45 calendar days but less than or	The responsible entity provided a response in more than 60 calendar	The responsible entity provided a response in more than 70 calendar days but less than or	The responsible entity failed to provide a response as required in more than 80 calendar

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Complete Violation Severity Level Matrix (FAC)
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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.	equal to 60 calendar days after a request.	days but less than or equal to 70 calendar days after a request. OR The responsible entity provided a response within 45 calendar days, and the response indicated that a change will not be made to the Facility Ratings Methodology but did not indicate why no change will be made.	equal to 80 calendar days after a request. OR The responsible entity provided a response within 45 calendar days, but the response did not indicate whether a change will be made to the Facility Ratings Methodology.	days after a request.
FAC-008-3	R1.	Each Generator Owner shall have documentation for determining the Facility Ratings of its solely and jointly owned generator Facility(ies) up to the low side terminals of the main step up transformer if the Generator Owner does not own the main step up transformer and the high side terminals of the main step up transformer if the Generator Owner owns the main step up transformer. [See standard for documentation requirements]	N/A	The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.1.	The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.2.	The Generator Owner failed to provide documentation for determining its Facility Ratings.
FAC-008-3	R2.	Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of interconnection with the Transmission Owner that contains all of the following. [See standard for methodology	The Generator Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R2: • 2.1.	The Generator Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R2: • 2.1	The Generator Owner's Facility Rating methodology did not address all the components of Requirement R2, Part 2.4. OR	The Generator Owner's Facility Rating methodology failed to recognize a facility's rating based on the most limiting component rating as required in Requirement R2, Part

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		requirements]	• 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	• 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner failed to include in its Facility Rating Methodology, three of the following Parts of Requirement R2: • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	2.3 OR The Generator Owner failed to include in its Facility Rating Methodology four or more of the following Parts of Requirement R2: • 2.1 • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4
FAC-008-3	R3.	Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following: [See standard for methodology requirements]	The Transmission Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner's Facility Rating methodology did not address either of the following Parts of Requirement R3: • 3.4.1 • 3.4.2 OR The Transmission Owner failed to include in its Facility Rating methodology three of the following Parts of Requirement R3: • 3.1	The Transmission Owner's Facility Rating methodology failed to recognize a Facility's rating based on the most limiting component rating as required in Requirement R3, Part 3.3 OR The Transmission Owner failed to include in its Facility Rating methodology four or more of the following Parts of Requirement R3:

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					• 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	• 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4
FAC-008-3	R4. (Retired)	Each Transmission Owner shall make its Facility Ratings methodology and each Generator Owner shall each make its documentation for determining its Facility Ratings and its Facility Ratings methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners and Planning Coordinators that have responsibility for the area in which the associated Facilities are located, within 21 calendar days of receipt of a request.	The responsible entity made its Facility Ratings methodology or Facility Ratings documentation available within more than 21 calendar days but less than or equal to 31 calendar days after a request.	The responsible entity made its Facility Ratings methodology or Facility Ratings documentation available within more than 31 calendar days but less than or equal to 41 calendar days after a request.	The responsible entity made its Facility Rating methodology or Facility Ratings documentation available within more than 41 calendar days but less than or equal to 51 calendar days after a request.	The responsible entity failed to make its Facility Ratings methodology or Facility Ratings documentation available in more than 51 calendar days after a request. (R3)
FAC-008-3	R5. (Retired)	If a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Coordinator provides documented comments on its technical review of a Transmission Owner's Facility Ratings methodology or Generator Owner's documentation for determining its Facility Ratings and its Facility Rating methodology, the Transmission Owner or Generator Owner shall provide a response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings methodology and, if no change will be made to that Facility Ratings methodology, the reason why.	The responsible entity provided a response in more than 45 calendar days but less than or equal to 60 calendar days after a request. (R5)	The responsible entity provided a response in more than 60 calendar days but less than or equal to 70 calendar days after a request. OR The responsible entity provided a response within 45 calendar days, and the response indicated that a change will not be made to the Facility	The responsible entity provided a response in more than 70 calendar days but less than or equal to 80 calendar days after a request. OR The responsible entity provided a response within 45 calendar days, but the response did not indicate whether a change will be made to the Facility Ratings methodology or Facility Ratings documentation.	The responsible entity failed to provide a response as required in more than 80 calendar days after the comments were received. (R5)

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Ratings methodology or Facility Ratings documentation but did not indicate why no change will be made. (R5)	(R5)	
FAC-008-3	R6.	Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings.	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for 5% or less of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 5% or more, but less than up to (and including) 10% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 10% up to (and including) 15% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than15% of its solely owned and jointly owned Facilities. (R6)
FAC-008-3	R7.	Each Generator Owner shall provide Facility Ratings (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) as scheduled by such requesting entities.	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to and including 15 calendar days.	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 15 calendar days but less than or equal to 25 calendar days.	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 25 calendar days but less than or equal to 35 calendar days.	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 35 calendar days. OR The Generator Owner failed to provide its Facility Ratings to the

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						requesting entities.
FAC-008-3	R8.	Each Transmission Owner (and each Generator Owner subject to Requirement R2) shall provide requested information as specified below (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s): [See standard for requirements of providing requested information]	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to and including 15 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 100%, but not less than or equal to 95% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR The responsible entity provided the required Rating information to the requesting entity, but the information was provided up to and including 15 calendar days late. (R8, Part 8.2) OR The responsible entity provided less than 100%, but not less than or equal to 95% of the required Rating information to the	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 15 calendar days but less than or equal to 25 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 95%, but not less than or equal to 90% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR The responsible entity provided the required Rating information to the requesting entity, but did so more 15 calendar days but less than or equal to 25 calendar days late. (R8, Part 8.2) OR The responsible	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 25 calendar days but less than or equal to 35 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 90%, but not less than or equal to 85% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR The responsible entity provided the required Rating information to the requesting entity, but did so more than 25 calendar days but less than or equal to 35 calendar days late. (R8, Part 8.2) OR The responsible entity provided less than 90%, but no less than or equal to 85% of the	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 35 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 85% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR The responsible entity provided the required Rating information to the requesting entity, but did so more than 35 calendar days late. (R8, Part 8.2) OR The responsible entity provided less than 85 % of the required Rating information to the requesting entity. (R8, Part 8.2) OR The responsible entity failed to provide its

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			requesting entity. (R8, Part 8.2)	entity provided less than 95%, but not less than or equal to 90% of the required Rating information to the requesting entity. (R8, Part 8.2)	required Rating information to the requesting entity. (R8, Part 8.2)	Rating information to the requesting entity. (R8, Part 8.1)
FAC-009-1	R1.	The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings Methodology.	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings Methodology for 5% or less of its solely owned and jointly owned Facilities.	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings Methodology for more than 5% up to (and including) 10% of its solely owned and jointly owned Facilities.	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings Methodology for more than 10% up to (and including) 15% of its solely owned and jointly owned Facilities.	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings Methodology for more than 15% of its solely owned and jointly owned Facilities.
FAC-009-1	R2.	The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.	The Transmission Owner or Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to 15 calendar days.	The Transmission Owner or Generator Owner provided its Facility Ratings to all but one of the requesting entities.	The Transmission Owner or Generator Owner provided its Facility Ratings to two of the requesting entities.	The Transmission Owner or Generator Owner has provided its Facility Ratings to none of the requesting entities within 30 calendar days of the associated schedules.
FAC-010-2.1	R1	The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1.

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				address R1.2		OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
FAC-010-2.1	R2.	The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance following single and multiple contingencies, but does not address the pre-contingency state (R2.1)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following single contingencies, but does not address multiple contingencies. (R2.5-R2.6)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state and following multiple contingencies, but does not meet the performance for response to single contingencies. (R2.2 – R2.4)	The Planning Authority's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state but does not require that SOLs be set to meet the BES performance specified for response to single contingencies (R2.2-R2.4) and does not require that SOLs be set to meet the BES performance specified for response to multiple contingencies. (R2.5-R2.6)
FAC-010-2.1	R3.	The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:	The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1	The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1	The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following:

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			through R3.6.	through R3.6.		R3.1 through R3.6.
FAC-010-2.1	R4.	The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60

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				the change.	changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
FAC-010-2.1	R5. (Retired)	If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority	The Planning Authority received documented technical	The Planning Authority received documented	The Planning Authority received documented technical comments on	The Planning Authority received documented technical

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.	comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.
FAC-011-2	R1.	The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
FAC-011-2	R2.	The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance	The Reliability Coordinator's SOL Methodology	Not applicable.	The Reliability Coordinator's SOL Methodology	The Reliability Coordinator's SOL Methodology

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		consistent with the following:	requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)		requires that SOLs are set to meet BES performance in the precontingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
FAC-011-2	R3.	The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.7.	The Reliability Coordinator has a methodology for determining SOLs that is missing a description of three or more of the following: R3.1 through R3.7.
FAC-011-2	R4	The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:	One or both of the following : The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30	One of the following: The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed	One of the following : The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less	One of the following: The Reliability Coordinator failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Reliability Coordinator issued its SOL Methodology and

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			calendar days after the effectiveness of the change.	methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	than 90 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.

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						OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Reliability Coordinator issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed

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						methodology was provided up to 30 calendar days after the effectiveness of the change.
FAC-011-2	R5. (Retired)	If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.
FAC-013-1	R1.	The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.	The responsible entity has established a set of Transfer Capabilities, but 5% or less of all Transfer Capabilities required to be established, are inconsistent with the current Transfer Capability	The responsible entity has established a set of Transfer Capabilities, but more than 5% up to (and including) 10% of all Transfer Capabilities required to be established,	The responsible entity has established a set of Transfer Capabilities, but more than 10% up to (and including) 15% of all Transfer Capabilities required to be established, are inconsistent with the current Transfer	The responsible entity has established a set of Transfer Capabilities, but more than 15% of those Transfer Capabilities are not consistent with the current Transfer Capability Methodology

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Methodology.	are inconsistent with the current Transfer Capability Methodology.	Capability Methodology.	OR The responsible entity has not established a set of Transfer Capabilities.
FAC-013-1	R2.	The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities that have a reliability-related need for such Transfer Capabilities and make a written request that includes a schedule for delivery of such Transfer Capabilities as follows:	The Reliability Coordinator or Planning Authority has provided its Transfer Capabilities but missed meeting one schedule by up to 15 calendar days.	The Reliability Coordinator or Planning Authority has provided its Transfer Capabilities but missed meeting two schedules.	The Reliability Coordinator or Planning Authority has provided its Transfer Capabilities but missed meeting more than two schedules.	The Reliability Coordinator or Planning Authority has provided its Transfer Capabilities but missed meeting all schedules within 30 calendar days of the associated schedules.
FAC-013-1	R2.1.	The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and to the Transmission Operators, Transmission Service Providers and Planning Authorities that work in its Reliability Coordinator Area.	The responsible entity failed to provide Transfer Capabilities to 5% or less of the required entities.	The responsible entity failed to provide Transfer Capabilities to more than 5% up to (and including) 10% of the required entities.	The responsible entity failed to provide Transfer Capabilities to more than 10% up to (and including) 15% of the required entities.	The responsible entity failed to provide Transfer Capabilities to more than 15% of the required entities.
FAC-013-1	R2.2.	The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the Transmission Planners and Transmission Service Provider(s) that work in its Planning Authority Area.	The responsible entity failed to provide Transfer Capabilities 5% or less of the required entities.	The responsible entity failed to provide Transfer Capabilities to more than 5% up to (and including) 10% of the required entities.	The responsible entity failed to provide Transfer Capabilities to more than 10% up to (and including) 15% of the required entities.	The responsible entity failed to provide Transfer Capabilities to more than 15% of the required entities.
FAC-013-2	R1.	Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following	The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate two of the following Parts of Requirement R1 into that methodology:	The Planning Coordinator did not have a Transfer Capability methodology. OR The Planning Coordinator has a

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		information: [See standard pdf for requirements of the Transfer Capability methodology]		into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.	• Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	Transfer Capability methodology, but failed to incorporate three or more of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.
FAC-013-2	R2.	Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: [See standard pdf for requirements of issuing the Transfer Capability Methodology]	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.	Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request	90 calendar days but not more than 120 calendar days after receipt of a request.	methodology more than 120 calendar days after receipt of a request.
FAC-013-2	R3. (Retired)	If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.	The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability methodology.
FAC-013-2	R4.	During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days,	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Planning Horizon.	calendar days.	more than 30 calendar days, but not by more than 60 calendar days.	but not by more than 90 calendar days.	calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.
FAC-013-2	R5.	Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5,, but not more than 60 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability methodology under the requirements of R5.
FAC-013-2	R6.	If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days	The Planning Coordinator provided the requested data as required in Requirement R6	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information.	after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	receipt of the request for data. OR The Planning Coordinator failed to provide the requested data as required in Requirement R6.
FAC-014-2	R1.	The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.	There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)	There are SOLs for the Reliability Coordinator Area, but 75% or more of these the SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)
FAC-014-2	R2.	The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)	The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)
FAC-014-2	R3.	The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.	There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these	There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of	There are SOLs for the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are	There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)	inconsistent with the Planning Coordinator's SOL Methodology. (R3)	with the Planning Coordinator's SOL Methodology. (R3)
FAC-014-2	R4.	The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	The Transmission Planner has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)	The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)
FAC-014-2	R5.	The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:	The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the	One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30	One of the following: The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5) OR The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				schedules for 15 or more but less than 30 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.4	or more but less than 45 calendar days. (R5) OR The supporting information provided with the IROLs does not address 5.1.3	
FAC-014-2	R6.	The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.	The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2	Not applicable.	The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)	The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6) OR The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)
FAC-501-WECC-1	R1.	Transmission Owners shall have a TMIP detailing their inspection and maintenance	The TMIP does not include associated	The TMIP does not include associated	The TMIP does not include associated	The TMIP does not include associated

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		requirements that apply to all transmission facilities necessary for System Operating Limits associated with each of the transmission paths identified in table titled "Major WECC Transfer Paths in the Bulk Electric System."	Facilities for one of the Paths identified in Attachment 1 FAC-501-WECC-1 as required by R.1 but Transmission Owners are performing maintenance and inspection for the missing Facilities.	Facilities for two of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.	Facilities for three of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.	Facilities for more than three of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.
FAC-501-WECC-1	R1.1.	Transmission Owners shall annually review their TMIP and update as required.	Transmission Owners did not review their TMIP annually as required by R.1.1.	N/A	N/A	N/A
FAC-501-WECC-1	R2.	Transmission Owners shall include the maintenance categories in Attachment 1-FAC-501-WECC-1 when developing their TMIP.	The TMIP does not include one maintenance category identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.	The TMIP does not include two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.	The TMIP does not include three maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.	The TMIP does not exist or does not include more than three maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.
FAC-501-WECC-1	R3.	Transmission Owners shall implement and follow their TMIP.	Transmission Owners do not have maintenance and inspection records as	Transmission Owners are not performing maintenance and	Transmission Owners are not performing maintenance and inspection for two	Transmission Owners are not performing maintenance and inspection for more

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			required by R.3 but have evidence that they are implementing and following their TMIP.	inspection for one maintenance category identified in Attachment 1 FAC-501-WECC-1 as required in R3.	maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required in R3.	than two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required in R3.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
INT-001-3	R1.	The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for:	The Load-Serving, Purchasing-Selling Entity experienced one instance of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for: (see below)	The Load-Serving, Purchasing-Selling Entity experienced two instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for: (see below)	The Load-Serving, Purchasing-Selling Entity experienced three instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for: (see below)	The Load-Serving, Purchasing-Selling Entity experienced four instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for: (see below)
INT-001-3	R1.1.	All Dynamic Schedules at the expected average MW profile for each hour.	The Load-Serving, Purchasing-Selling Entity experienced one instance of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for all Dynamic Schedules at the expected average MW profile for each hour.	The Load-Serving, Purchasing-Selling Entity experienced two instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for all Dynamic Schedules at the expected average MW profile for each hour.	The Load-Serving, Purchasing-Selling Entity experienced three instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for all Dynamic Schedules at the expected average MW profile for each hour.	The Load-Serving, Purchasing-Selling Entity experienced four instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for all Dynamic Schedules at the expected average MW profile for each hour.
INT-001-3	R2.	The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority:	The Sink Balancing Authority experienced one instance of failing to ensure that Arranged Interchange was submitted to the Interchange Authority (see below)	The Sink Balancing Authority experienced two instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority (see below)	The Sink Balancing Authority experienced three instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority (see below)	The Sink Balancing Authority experienced four instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority (see below)

Complete Violation Severity Level Matrix (INT)
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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
INT-001-3	R2.1.	If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator.	The Sink Balancing Authority experienced one instance of failing to ensure that Arranged Interchange was submitted to the Interchange Authority if a Purchasing-Selling Entity was not involved in the Interchange, such as delivery from a jointly owned generator.	The Sink Balancing Authority experienced two instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority if a Purchasing-Selling Entity was not involved in the Interchange, such as delivery from a jointly owned generator.	The Sink Balancing Authority experienced three instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority if a Purchasing-Selling Entity was not involved in the Interchange, such as delivery from a jointly owned generator.	The Sink Balancing Authority experienced four instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority if a Purchasing-Selling Entity was not involved in the Interchange, such as delivery from a jointly owned generator.
INT-001-3	R2.2.	For each bilateral Inadvertent Interchange payback.	The Sink Balancing Authority experienced one instance of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for each bilateral Inadvertent Interchange payback.	The Sink Balancing Authority experienced two instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for each bilateral Inadvertent Interchange payback.	The Sink Balancing Authority experienced three instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for each bilateral Inadvertent Interchange payback.	The Sink Balancing Authority experienced four instances of failing to ensure that Arranged Interchange was submitted to the Interchange Authority for each bilateral Inadvertent Interchange payback.
INT-003-3	R1.	Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.	There shall be a separate Lower VSL, if either of the following conditions exists: One instance of entering a schedule into its ACE equation without confirming the	There shall be a separate Moderate VSL, if either of the following conditions exists: Two instances of entering a schedule into its ACE equation	There shall be a separate High VSL, if either of the following conditions exists: Three instances of entering a schedule into its ACE equation without confirming the schedule	There shall be a separate Severe VSL, if either of the following conditions exists: Four or more instances of entering a schedule into its ACE equation without

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. One instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	as specified in R1, R1.1, R1.1.1 and R1.1.2. Three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Four or more instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2
INT-003-3	R1.1.	The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including:	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
INT-003-3	R1.1.1.	Interchange Schedule start and end time.	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
INT-003-3	R1.1.2	Energy profile.	The Balancing Authority experienced	The Balancing Authority	The Balancing Authority experienced	The Balancing Authority experienced

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
INT-003-3	R1.2.	If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie.	The sending or receiving Balancing Authority experienced one instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced four instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2
INT-004-2	R1.	At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.	The entity that initiated the curtailment failed to communicate the transaction reload to the Sink Balancing Authority	The entity that initiated the curtailment failed to reload the transaction and failed to communicate to the Sink Balancing Authority	N/A	N/A
INT-004-2	R2.	The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occurs:	N/A	N/A	The responsible entity failed to update the tag when required by sub-requirements R2.1 or R2.2.	The responsible entity failed to update the tag when required by sub-requirement R2.3.
INT-004-2	R2.1.	The average energy profile in an hour is greater than 250 MW and in that hour the	N/A	N/A	N/A	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +10%.				
INT-004-2	R2.2.	The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +25 megawatt-hours.	N/A	N/A	N/A	N/A
INT-004-2	R2.3.	A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.	N/A	N/A	N/A	N/A
INT-005-3	R1.	Prior to the expiration of the time period defined in the timing requirements tables in this standard, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange.	The Interchange Authority experienced one occurrence of not distributing information to all involved reliability entities.	The Interchange Authority experienced two occurrences of not distributing information to all involved reliability entities	The Interchange Authority experienced three occurrences of not distributing information to all involved reliability entities	The Interchange Authority experienced four occurrences of not distributing information to all involved reliability entities
INT-005-3	R1.1.	When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority.	N/A	N/A	The Responsible Entity initiated a Curtailment to Confirmed or Implemented Interchange for reliability but the Interchange Authority failed to distribute the Arranged Interchange information to the Source Balancing Authority or the Sink Balancing Authority.	The Responsible Entity initiated a Curtailment to Confirmed or Implemented Interchange for reliability but the Interchange Authority failed to distribute the Arranged Interchange information to the Source Balancing Authority and the Sink Balancing Authority.
INT-006-3	R1.	Prior to the expiration of the reliability	The Responsible	The Responsible	The Responsible Entity	The Responsible

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		assessment period defined in the timing requirements tables in this standard, Column B, the Balancing Authority and Transmission Service Provider shall respond to each On-time Request for Interchange (RFI), and to each Emergency RFI and Reliability Adjustment RFI from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange	Entity failed on one occasion to respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.	Entity failed on two occasions to respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.	failed on three occasions to respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.	Entity failed on four occasions to respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.
INT-006-3	R1.1.	Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to:	The Balancing Authority failed to evaluate arranged interchange with respect to one of the requirements in the 3 sub-components.	N/A	The Balancing Authority failed to evaluate arranged interchange with respect to two of the requirements in the 3 sub-components.	The Balancing Authority failed to evaluate arranged interchange with respect to three of the requirements in the 3 sub-components.
INT-006-3	R1.1.1.	Energy profile (ability to support the magnitude of the Interchange).	N/A	N/A	N/A	The Balancing Authority failed to evaluate Energy profile (ability to support the magnitude of the Interchange).
INT-006-3	R1.1.2.	Ramp (ability of generation maneuverability to accommodate).	N/A	N/A	N/A	The Balancing Authority failed to evaluate Ramp (ability of generation maneuverability to accommodate).
INT-006-3	R1.1.3.	Scheduling path (proper connectivity of Adjacent Balancing Authorities).	N/A	N/A	N/A	The Balancing Authority failed to evaluate Scheduling path (proper connectivity of Adjacent Balancing Authorities).

Complete Violation Severity Level Matrix (INT)
Encompassing All Commission-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
INT-006-3	R1.2.	Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated	The Transmission Service Provider experienced one instance of failing to confirm that the transmission service arrangements associated with the Arranged Interchange had adjacent Transmission Service Provider connectivity, were valid and prevailing transmission system limits would not be violated.	The Transmission Service Provider experienced two instances of failing to confirm that the transmission service arrangements associated with the Arranged Interchange had adjacent Transmission Service Provider connectivity, were valid and prevailing transmission system limits would not be violated.	The Transmission Service Provider experienced three instances of failing to confirm that the transmission service arrangements associated with the Arranged Interchange had adjacent Transmission Service Provider connectivity, were valid and prevailing transmission system limits would not be violated.	The Transmission Service Provider experience four instances of failing to confirm that the transmission service arrangements associated with the Arranged Interchange had adjacent Transmission Service Provider connectivity, were valid and prevailing transmission system limits would not be violated.
INT-007-1	R1.	The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following:	The Interchange Authority failed to verify one time, as indicated in R1.1, ~~R1.2,~~ R1.3, R1.3.1, R1.3.2, R1.3.3, or R1.3.4 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange. (R1.2 retired)	The Interchange Authority failed to verify two times, as indicated in R1.1, ~~R1.2,~~ R1.3, R1.3.1, R1.3.2, R1.3.3, or R1.3.4 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange. (R1.2 retired)	The Interchange Authority failed to verify three times, as indicated in R1.1, ~~R1.2,~~ R1.3, R1.3.1, R1.3.2, R1.3.3, or R1.3.4 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange. (R1.2 retired)	The Interchange Authority failed to verify four times, as indicated in R1.1, ~~R1.2,~~ R1.3, R1.3.1, R1.3.2, R1.3.3, or R1.3.4 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange. (R1.2 retired)
INT-007-1	R1.1.	Source Balancing Authority megawatts equal sink Balancing Authority megawatts	The Interchange Authority failed to	The Interchange Authority failed to	The Interchange Authority failed to	The Interchange Authority failed to

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		(adjusted for losses, if appropriate).	verify one time, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	verify two times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	verify three times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	verify four times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.
INT-007-1	R1.2. (Retired)	All reliability entities involved in the Arranged Interchange are currently in the NERC registry.	The Interchange Authority failed to verify one time, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify two times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify three times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify four times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.
INT-007-1	R1.3.	The following are defined:	The Interchange Authority failed to verify one time, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify two times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify three times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify four times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.
INT-007-1	R1.3.1.	Generation source and load sink.	The Interchange Authority failed to verify one time, as	The Interchange Authority failed to verify two times, as	The Interchange Authority failed to verify three times, as	The Interchange Authority failed to verify four times, as

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.
INT-007-1	R1.3.2.	Megawatt profile.	The Interchange Authority failed to verify one time, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify two times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify three times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify four times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.
INT-007-1	R1.3.3.	Ramp start and stop times.	The Interchange Authority failed to verify one time, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify two times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify three times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	The Interchange Authority failed to verify four times, as indicated in R1 that Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.
INT-007-1	R1.3.4.	Interchange duration.	The Interchange Authority failed to verify one time, as indicated in R1 that	The Interchange Authority failed to verify two times, as indicated in R1 that	The Interchange Authority failed to verify three times, as indicated in R1 that	The Interchange Authority failed to verify four times, as indicated in R1 that

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.	Arranged Interchange was balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.
INT-007-1	R1.4.	Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.	Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval, with minor exception and is substantially compliant with the directives of the requirement.	Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval, with some exception and is mostly compliant with the directives of the requirement.	Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval but was substantially deficient in meeting the directives of the requirement.	Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment did not provided approval and failed to meet the requirement.
INT-008-3	R1.	Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the Arranged Interchange has transitioned to a Confirmed Interchange.	The Interchange Authority experienced one occurrence of not distributing information to all involved reliability entities as deliniated in R1.1, R1.1.1 or R1.1.2.	The Interchange Authority experienced two occurrences of not distributing information to all involved reliability entities.	The Interchange Authority experienced three occurrences of not distributing information to all involved reliability entities.	The Interchange Authority experienced four occurrences of not distributing information to all involved reliability entities or no evidence provided.
INT-008-3	R1.1.	For Confirmed Interchange, the Interchange	The Interchange	The Interchange	The Interchange	The Interchange

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Authority shall also communicate:	Authority experienced one occurrence of not distributing information to all involved reliability entities as defined in R1.	Authority experienced two occurrences of not distributing information to all involved reliability entities as defined in R1.	Authority experienced three occurrences of not distributing information to all involved reliability entities as defined in R1.	Authority experienced four occurrences of not distributing information to all involved reliability entities as defined in R1 or no evidence provided.
INT-008-3	R1.1.1.	Start and stop times, ramps, and megawatt profile to Balancing Authorities.	The Interchange Authority experienced one occurrence of not distributing information to all involved reliability entities as defined in R1.	The Interchange Authority experienced two occurrences of not distributing information to all involved reliability entities as defined in R1.	The Interchange Authority experienced three occurrences of not distributing information to all involved reliability entities as defined in R1.	The Interchange Authority experienced four occurrences of not distributing information to all involved reliability entities as defined in R1 or no evidence provided.
INT-008-3	R1.1.2.	Necessary Interchange information to NERC-identified reliability analysis services.	The Interchange Authority experienced one occurrence of not distributing information to all involved reliability entities as defined in R1.	The Interchange Authority experienced two occurrences of not distributing information to all involved reliability entities as defined in R1.	The Interchange Authority experienced three occurrences of not distributing information to all involved reliability entities as defined in R1.	The Interchange Authority experienced four occurrences of not distributing information to all involved reliability entities as defined in R1 or no evidence provided.
INT-009-1	R1.	The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority.	N/A	N/A	N/A	The responsible entity failed to implement a Confirmed Interchange as received from the Interchange Authority.
INT-010-1	R1.	The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is submitted with a start time no more than 60 minutes	The responsible entity that experienced a loss of resources that exceeded 60 minutes and was covered by an	The responsible entity that experienced a loss of resources that exceeded 60	The responsible entity that experienced a loss of resources that exceeded 60 minutes and was covered by an	The responsible entity that experienced a loss of resources that exceeded 60 minutes and was covered by an

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no request for Arranged Interchange is required.	energy sharing agreement ensured that a request for an Arranged Interchange was submitted, but with a start time that was more than 60 minutes but less than 75 minutes beyond the resource loss.	minutes and was covered by an energy sharing agreement ensured that a request for an Arranged Interchange was submitted, but with a start time that was 75 minutes or more, but less than 90 minutes beyond the resource loss.	energy sharing agreement ensured that a request for an Arranged Interchange was submitted, but with a start time that was 90 minutes or more, but less than 105 minutes beyond the resource loss.	energy sharing agreement ensured that a request for an Arranged Interchange was submitted, but with a start time that was more than 105 minutes beyond the resource loss. OR The responsible entity that experienced a loss of resources that exceeded 60 minutes and was covered by an energy sharing agreement, failed to ensure that a request for an Arranged Interchange was submitted.
INT-010-1	R2.	For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event.	N/A	N/A	N/A	The responsible entity failed to direct a Balancing Authority to submit the modified Arranged Interchange reflecting the modification, within 60 minutes of the initiation of the event.
INT-010-1	R3.	For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit an Arranged Interchange reflecting that Interchange schedule within 60 minutes of	N/A	N/A	N/A	The responsible entity failed to direct a Balancing Authority to submit an Arranged Interchange reflecting the new Interchange schedule within 60

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the initiation of the event.				minutes of the initiation of the event.

Complete Violation Severity Level Matrix (IRO)
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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
IRO-001-1.1	R1.	Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.	The RRO, subregion or interregional coordinating group did not communicate the assignment of the Reliability Coordinators to operating entities clearly.	The RRO, subregion or interregional coordinating group did not clearly identify the coordination of Reliability Coordinator areas within the region.	The RRO, subregion or interregional coordinating group did not coordinate assignment of the Reliability Coordinators across regional boundaries.	The RRO, subregion or interregional coordinating group did not assign any Reliability Coordinators.
IRO-001-1.1	R2.	The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.	The Reliability Coordinator has failed to follow the administrative portions of its regional reliability plan.	The Reliability Coordinator has failed to follow steps in its regional reliability plan that requires operator interventions or actions.	The Reliability Coordinator does not have a regional reliability plan approved by the NERC OC.	The Reliability Coordinator does not have an unapproved regional reliability plan.
IRO-001-1.1	R3.	The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.	N/A	N/A	The Reliability Coordinator cannot demonstrate that it has clear authority to act or direct actions to preserve transmission security and reliability of the Bulk Electric System.	The Reliability Coordinator failed to take or direct to preserve the reliability and security of the Bulk Electric System within 30 minutes of identifying those actions.
IRO-001-1.1	R4.	Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area. All	1. Less than 25% of the tasks are not documented in the agreement or 2. Less than 25% of the tasks are not performed according	1. More than 25% but 50% or less of the tasks are not documented in the agreement or 2. More than 25% but 50% or less of	1. More than 50% but 75% or less of the tasks are not documented in the agreement or 2. More than 50% but 75% or less of the tasks are not performed	1. There is no formal operating agreement for tasks delegated by the Reliability Coordinator, 2. More than 75% of the tasks are not

Complete Violation Severity Level Matrix (IRO)
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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.	to the agreement.	the tasks are not performed according to the agreement.	according to the agreement.	documented in the agreement or 3. More than 75% of the tasks are not performed according to the agreement.
IRO-001-1.1	R5.	The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.	5% or less of the delegate entities are not identified in the reliability plan.	More than 5% up to (and including) 10% of the delegate entities are not identified in the reliability plan.	More than 10% up to (and including) 15% of the delegate entities are not identified in the reliability plan.	There is no reliability plan. OR More than 15% of the delegate entities are not identified in the reliability plan.
IRO-001-1.1	R6.	The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.	The Reliability Coordinator failed to demonstrate that 5% or less of its delegated tasks were being performed by NERC certified Reliability Coordinator operating personnel.	The Reliability Coordinator failed to demonstrate that more than 5% up to (and including) 10% of its delegated tasks were being performed by NERC certified Reliability Coordinator operating personnel.	The Reliability Coordinator failed to demonstrate that more than 10% up to (and including) 15% of its delegated tasks were being performed by NERC certified Reliability Coordinator operating personnel.	The Reliability Coordinator failed to demonstrate that more than 15% of its delegated tasks were being performed by NERC certified Reliability Coordinator operating personnel.
IRO-001-1.1	R7.	The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit or Interconnection Reliability Operating Limit violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.	The Reliability Coordinator has demonstrated the existence of coordination agreements with adjacent Reliability Coordinators but the agreements are not clear or comprehensive.	The Reliability Coordinator has demonstrated the existence of the coordination agreements with adjacent Reliability Coordinators but the agreements do not coordinate actions required in the adjacent Reliability Coordinator to	The Reliability Coordinator has demonstrated the existence of the coordination agreements with adjacent Reliability Coordinators but the agreements do not coordinate actions required in the adjacent Reliability Coordinator to mitigate SOL and	The Reliability Coordinator has failed to demonstrate the existence of any coordination agreements with adjacent Reliability Coordinators.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				mitigate SOL or IROL violations in its own Reliability Coordinator area.	IROL violations in its own Reliability Coordinator area.	
IRO-001-1.1	R8.	Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.	N/A	The responsible entity could not comply with a directive due to qualified reasons (violation of safety, equipment or regulatory or statutory requirements) and did not immediately inform the Reliability Coordinator.	N/A	The responsible entity did not follow the Reliability Coordinator's directive.
IRO-001-1.1	R9.	The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity.	N/A	N/A	N/A	The Reliability Coordinator did not act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of one or more other entities.
IRO-003-2	R1.	Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time,	N/A	N/A	The Reliability Coordinator failed to monitor **all** Bulk Electric System facilities, which may include sub-	The Reliability Coordinator failed to monitor Bulk Electric System facilities, which may include sub-transmission

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.			transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.	information, within adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.
IRO-003-2	R2.	Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.	N/A	N/A	The Reliability Coordinator failed to know either the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation or the status of any facilities that may be required to assist area restoration objectives.	The Reliability Coordinator failed to know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation and the status of any facilities that may be required to assist area restoration objectives.
IRO-006-5	R1.	Each Reliability Coordinator and Balancing Authority that receives a request pursuant to an Interconnection-wide transmission loading relief procedure (such as Eastern Interconnection TLR, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from	N/A	N/A	N/A	The responsible entity received a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		any Reliability Coordinator, Balancing Authority, or Transmission Operator in another Interconnection to curtail an Interchange Transaction that crosses an Interconnection boundary shall comply with the request, unless it provides a reliability reason to the requestor why it cannot comply with the request.				wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority, or Transmission Operator, but the entity neither complied with the request, nor provided a reliability reason why it could not comply with the request.
IRO-006-EAST-1	R1.	When acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's TV, each Reliability Coordinator shall initiate, prior to or concurrently with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated), one or more of the following actions: • Inter-area redispatch of generation • Intra-area redispatch of generation • Reconfiguration of the transmission system • Voluntary load reductions (e.g., Demand-side Management) • Controlled load reductions (e.g., load shedding)	N/A	N/A	N/A	When acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's Tv, the Reliability Coordinator did not initiate one or more of the actions listed under R1 prior to or in conjunction with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated).
IRO-006-EAST-1	R2.	To ensure operating entities are provided with information needed to maintain an	The Reliability Coordinator initiating	The Reliability Coordinator	The Reliability Coordinator initiating	The Reliability Coordinator initiating

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		awareness of changes to the Transmission System, when initiating the Eastern Interconnection TLR procedure to prevent or mitigate an SOL or IROL exceedance, and at least every clock hour (with the exception of TLR-1, where an hourly update is not required) after initiation up to and including the hour when the TLR level has been identified as TLR Level 0, the Reliability Coordinator shall identify: 2.1. A list of congestion management actions to be implemented, and 2.2. One of the following TLR levels: TLR-1, TLR-2, TLR-3A, TLR-3B, TLR-4, TLR-5A, TLR-5B, TLR-6, TLR-0	the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for one clock hour during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for two clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for three clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for four or more clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.
IRO-006-EAST-1	R3.	Upon the identification of the TLR level and a list of congestion management actions to be implemented, the Reliability Coordinator initiating this TLR procedure shall: o Notify all Reliability Coordinators in the Eastern Interconnection of the identified TLR level o Communicate the list of congestion management actions to be implemented to 1.) all Reliability Coordinators in the Eastern Interconnection, and 2.) those Reliability Coordinators in other Interconnections responsible for curtailing Interchange Transactions crossing Interconnection boundaries identified in the list of congestion management actions. o Request that the congestion management actions identified in Requirement R2, Part 2.1 be	The initiating Reliability Coordinator did not notify one or more Reliability Coordinators in the Eastern Interconnection of the TLR Level (3.1).	N/A	The initiating Reliability Coordinator did not communicate the list of congestion management actions to one or more of the Reliability Coordinators listed in Requirement R3, Part 3.2. OR The initiating Reliability Coordinator requested some, but not all, of the Reliability Coordinators identified in Requirement R3, Part 3.3 to implement the identified	The initiating Reliability Coordinator requested none of the Reliability Coordinators identified in Requirement R3, Part 3.3 to implement the identified congestion management actions.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		implemented by: 1.) Each Reliability Coordinator associated with a Sink Balancing Authority for which Interchange Transactions are to be curtailed, 2.) Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which Network Integration Transmission Service or Native Load is to be curtailed, and 3.) Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which its Market Flow is to be curtailed.			congestion management actions.	
IRO-006-EAST-1	R4.	Each Reliability Coordinator that receives a request as described in Requirement R3, Part 3.3. shall, within 15 minutes of receiving the request, implement the congestion management actions requested by the issuing Reliability Coordinator as follows: • Instruct its Balancing Authorities to implement the Interchange Transaction schedule change requests. • Instruct its Balancing Authorities to implement the Network Integration Transmission Service and Native Load schedule changes for which the Balancing Authorities are responsible. • Instruct its Balancing Authorities to implement the Market Flow schedule changes for which the Balancing Authorities are responsible. • If an assessment determines shows that	N/A	N/A	N/A	The responding Reliability Coordinator did not, within 15 minutes of receiving a request, either 1.) implement all the requested congestion management actions, or 2.) implement none or some of the requested congestion management actions and replace the remainder with alternate congestion management actions, provided that: assessment showed that the actions replaced would have

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		one or more of the congestion management actions communicated in Requirement R3, Part 3.3 will result in a reliability concern or will be ineffective, the Reliability Coordinator may replace those specific actions with alternate congestion management actions, provided that: o The alternate congestion management actions have been agreed to by the initiating Reliability Coordinator, and o The assessment shows that the alternate congestion management actions will not adversely affect reliability.				resulted in a reliability concern or would have been ineffective, the alternate congestion management actions were agreed to by the initiating Reliability Coordinator, and assessment determined that the alternate congestion management actions would not adversely affect reliability.
IRO-006-TRE-1	R1.	The RC shall have procedures to identify and mitigate exceedances of identified Interconnection Reliability Operating Limits (IROL) and System Operating Limits (SOL) that will not be resolved by the automatic actions of the ERCOT Nodal market operations system. The procedures shall address, but not be limited to, one or more of the following: redispatch of generation; reconfiguration of the Transmission system; controlled load reductions (including both firm and non-firm load shedding).	N/A	N/A	N/A	The RC did not have procedures to identify and mitigate exceedances of identified IROLs and SOLs.
IRO-006-TRE-1	R2.	The RC shall act to identify and mitigate exceedances of identified Interconnection Reliability Operating Limits and System Operating Limits that will not be resolved by the automatic actions of the ERCOT Nodal market operations system, in accordance with the procedures required by R1.	N/A	N/A	The RC failed to follow its procedures in identifying and mitigating an exceedance of an SOL.	The RC failed to follow its procedures in identifying and mitigating an exceedance of an IROL.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
IRO-006-WECC-1	R1.	Upon receiving a request of Step 4 or greater (see Attachment 1-IRO-006-WECC-1) from the Transmission Operator of a Qualified Transfer Path, the Reliability Coordinator shall approve (actively or passively) or deny that request within five minutes.	There shall be a Lower Level of non-compliance if there is one instance during a calendar month in which the Reliability Coordinator approved (actively or passively) or denied a Step 4 or greater request greater than five minutes after receipt of notification from the Transmission Operator of a Qualified Transfer Path.	N/A	N/A	N/A
IRO-006-WECC-1	R2.	The Balancing Authorities shall approve curtailment requests to the schedules as submitted, implement alternative actions, or a combination there of that collectively meets the Relief Requirement.	There shall be a Lower Level of non-compliance if there is less than 100% Relief Requirement provided but greater than or equal to 90% Relief Requirement provided or the Relief Requirement was less than 5 MW and was not provided.	There shall be a Moderate Level of non-compliance if there is less than 90% Relief Requirement provided but greater than or equal to 75% Relief Requirement provided and the Relief Requirement was greater than 5 MW and was not provided.	There shall be a High Level of non-compliance if there is less than 75% Relief Requirement provided but greater than or equal to 60% Relief Requirement provided and the Relief Requirement was greater than 5 MW and was not provided.	There shall be a Severe Level of non-compliance if there is less than 60% Relief Requirement provided and the Relief Requirement was greater than 5 MW and was not provided.
IRO-014-1	R1.	The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios	N/A	N/A	The Reliability Coordinator has Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or	The Reliability Coordinator failed to have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators.			coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability, but failed to address Scenarios that affect other Reliability Coordinator Areas.	coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability.
IRO-014-1	R1.1.	These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:	N/A	The Reliability Coordinator failed to include one of the elements listed in IRO-014-1 R1.1.1 through R1.1.6 in its Operating Procedures, Processes, or Plans.	The Reliability Coordinator failed to include two of the elements listed in IRO-014-1 R1.1.1 through R1.1.6 in its Operating Procedures, Processes, or Plans.	The Reliability Coordinator failed to include more than two of the elements listed in IRO-014-1 R1.1.1 through R1.1.6 in its Operating Procedures, Processes, or Plans.
IRO-014-1	R1.1.1.	Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.	N/A	N/A	N/A	N/A
IRO-014-1	R1.1.2.	Energy and capacity shortages.	N/A	N/A	N/A	N/A
IRO-014-1	R1.1.3.	Planned or unplanned outage information.	N/A	N/A	N/A	N/A
IRO-014-1	R1.1.4.	Voltage control, including the coordination of reactive resources for voltage control.	N/A	N/A	N/A	N/A
IRO-014-1	R1.1.5.	Coordination of information exchange to support reliability assessments.	N/A	N/A	N/A	N/A
IRO-014-1	R1.1.6.	Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.	N/A	N/A	N/A	N/A

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
IRO-014-1	R2.	Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be:	N/A	N/A	N/A	The Reliability Coordinator's Operating Procedure, Process, or Plan failed to comply with either IRO-014-1 R2.1 or R2.2.
IRO-014-1	R2.1.	Agreed to by all the Reliability Coordinators required to take the indicated action(s).	N/A	N/A	N/A	The Reliability Coordinator's Operating Procedure, Process, or Plan was not agreed to by all the Reliability Coordinators required to take the indicated action(s).
IRO-014-1	R2.2.	Distributed to all Reliability Coordinators that are required to take the indicated action(s).	N/A	N/A	N/A	The Reliability Coordinator's Operating Procedure, Process, or Plan was not distributed to all Reliability Coordinators that are required to take the indicated action(s).
IRO-014-1	R3.	A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include:	N/A	N/A	N/A	The Reliability Coordinator's Operating Procedure, Process, or Plan failed to comply with either IRO-014-1 R3.1 or R3.2.
IRO-014-1	R3.1.	A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	N/A	N/A	N/A	The Reliability Coordinator's Operating Procedure, Process, or Plan failed to reference the

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.
IRO-014-1	R3.2.	The agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	N/A	N/A	N/A	The Reliability Coordinator's Operating Procedure, Process, or Plan failed to include the agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.
IRO-014-1	R4.	Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall:	N/A	The Operating Procedures, Processes and Plans did not include **one** of the elements listed in IRO-014-1 R4.1 through R4.3.	The Operating Procedures, Processes and Plans did not include **two** of the elements listed in IRO-014-1 R4.1 through R4.3.	The Operating Procedures, Processes and Plans did not include **any** of the elements listed in IRO-014-1 R4.1 through R4.3.
IRO-014-1	R4.1.	Include version control number or date	N/A	N/A	N/A	N/A
IRO-014-1	R4.2.	Include a distribution list.	N/A	N/A	N/A	N/A
IRO-014-1	R4.3.	Be reviewed, at least once every three years, and updated if needed.	N/A	N/A	N/A	N/A
IRO-015-1	R1.	The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability Coordinators.	N/A	The Reliability Coordinator failed to follow its Operating Procedures, Processes, or Plans for making	N/A	The Reliability Coordinator failed to follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				notifications and exchanging reliability-related information with other Reliability Coordinators but no adverse reliability impacts resulted from the incident.		related information with other Reliability Coordinators and adverse reliability impacts resulted from the incident.
IRO-015-1	R1.1.	The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.	N/A	The Reliability Coordinator failed to make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas but no adverse reliability impacts resulted from the incident.	N/A	The Reliability Coordinator failed to make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas and adverse reliability impacts resulted from the incident.
IRO-015-1	R2.	The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators.	N/A	N/A	N/A	The Reliability Coordinator failed to participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators.
IRO-015-1	R2.1.	The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.	N/A	N/A	N/A	The Reliability Operator failed to participate in the

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						assessment of the need and frequency of conference calls with other Reliability Operators.
IRO-015-1	R3.	The Reliability Coordinator shall provide reliability-related information as requested by other Reliability Coordinators.				The Reliability Coordinator failed to provide reliability-related information as requested by other Reliability Coordinators.
IRO-016-1	R1.	The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.	The Reliability Coordinator that identified a potential, expected, or actual problem that required the actions of one or more other Reliability Coordinators, contacted the other Reliability Coordinator(s) to confirm that there was a problem, discussed options and decided upon a solution to prevent or resolve the identified problem, but failed to have evidence that it coordinated with other Reliability Coordinators.	N/A	N/A	The Reliability Coordinator that identified a potential, expected, or actual problem that required the actions of one or more other Reliability Coordinators failed to contact the other Reliability Coordinator(s) to confirm that there was a problem, discuss options and decide upon a solution to prevent or resolve the identified problem.
IRO-016-1	R1.1.	If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall	The responsible entity agreed on the problem and the actions to take to prevent or mitigate	N/A	N/A	The responsible entity agreed on the problem and the actions to take to prevent or mitigate

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken.	the system condition, implemented the agreed-upon solution, but failed to notify the involved Reliability Coordinators of the action(s) taken.			the system condition, but failed to implement the agreed-upon solution.
IRO-016-1	R1.2.	If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.).	N/A	N/A	N/A	The involved Reliability Coordinators could not agree on the problem(s), but a Reliability Coordinator failed to re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.).
IRO-016-1	R1.2.1.	If time permits, this re-evaluation shall be done before taking corrective actions.	N/A	N/A	N/A	The Reliability Coordinator failed to re-evaluate the problem prior to taking corrective actions, during periods when time was not an issue.
IRO-016-1	R1.2.2.	If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved.	N/A	N/A	N/A	The Reliability Coordinator failed to operate as though the problem(s) exist(s) until the conflicting system status was resolved, during periods when time was an issue.
IRO-016-1	R1.3.	If the involved Reliability Coordinators cannot agree on the solution, the more	N/A	N/A	N/A	The Reliability Coordinator

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		conservative solution shall be implemented.				implemented a solution other than the most conservative solution, when agreement on the solution could not be reached.
IRO-016-1	R2. (Retired)	The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.	N/A	N/A	N/A	The Reliability Coordinator failed to document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.

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Complete Violation Severity Level Matrix (MOD)
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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
MOD-010-0	R1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R 1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide less than or equal to 25% of the appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R 1	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 25% but less than or equal to 50% of the appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 50% but less than or equal to 75% of the appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 75% of the appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R1.
MOD-010-0	R2.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. If no schedule exists, then	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide less than or equal to 25% of the steady-state modeling and simulation data to	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 25% but less than or equal to	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 50% but less than or equal to 75% of the steady-state modeling	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 75% of the steady-state modeling and simulation data to the

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		these entities shall provide the data on request (30 calendar days).	the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. OR If no schedule exists, The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners provided data more than 30 but less than or equal to 35 calendar days following the request.	50% of the steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. OR If no schedule exists, The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners provided data more than 35 but less than or equal to 40 calendar days following the request.	and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. OR If no schedule exists, The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners provided data more than 40 but less than or equal to 45 calendar days following the request.	Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. OR If no schedule exists, The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide data more than 45 calendar days following the request.
MOD-012-0	R1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide less than or equal to 25% of the appropriate equipment characteristics and system data in compliance with the respective	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 25% but less than 50% of the appropriate equipment characteristics and	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 50% but less than 75% of the appropriate equipment characteristics and system data in compliance with the	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 75% of the appropriate equipment characteristics and system data in compliance with the respective

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1	system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.	respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.	Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.
MOD-012-0	R2.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R 1. If no schedule exists, then these entities shall provide data on request (30 calendar days).	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide less than or equal to 25% of the dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R 1 OR If no schedule exists, The Transmission Owners, Transmission Planners, Generator Owners, and Resource	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 25% but less than 50% of the dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R 1. OR If no schedule exists, The	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 50% but less than 75% of the dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R 1. OR If no schedule exists, The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners provided data	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to provide greater than 75% of the dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R 1. OR If no schedule exists, The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners failed to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Planners provided data more than 30 but less than or equal to 35 calendar days following the request.	Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners provided data more than 35 but less than or equal to 40 calendar days following the request.	more than 40 but less than or equal to 45 calendar days following the request.	provide data more than 45 calendar days following the request.
MOD-016-1.1	R1.	The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses.	N/A	The responsible entity did not have documentation identifying the scope and details of the actual and forecast data for one (1) of the following types of data to be reported for system modeling and reliability analyses: • Demand data • Net Energy for Load data • Controllable DSM data	The responsible entity did not have documentation identifying the scope and details of the actual and forecast data for two (2) of the following to be reported for system modeling and reliability analyses: • Demand data • Net Energy for Load data • Controllable DSM data	The responsible entity did not have documentation identifying the scope and details of the actual and forecast data to be reported for system modeling and reliability analyses.
MOD-016-1.1	R1.1.	The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005, TPL-006, MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, and MOD-021. The data submittal requirements shall stipulate that	The responsible entity failed to ensure that consistent data is supplied for one of the Reliability Standards as specified in R1.1.	The responsible entity failed to ensure that consistent data is supplied for two of the Reliability Standards as specified in R1.1.	The responsible entity failed to ensure that consistent data is supplied for three of the Reliability Standards as specified in R1.1.	The responsible entity failed to ensure that consistent data is supplied for four or more of the Reliability Standards as specified in R1.1.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values.				OR The responsible entity failed to stipulate that each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values.
MOD-016-1.1	R2.	The Regional Reliability Organization shall distribute its documentation required in Requirement 1 and any changes to that documentation, to all Planning Authorities that work within its Region.	N/A	N/A	The Regional Reliability Organization distributed its documentation as specified in R1 but failed to distribute any changes to that documentation, to all Planning Authorities that work within its Region.	The Regional Reliability Organization failed to distribute its documentation as specified in R1 to all Planning Authorities that work within its Region.
MOD-016-1.1	R2.1.	The Regional Reliability Organization shall make this distribution within 30 calendar days of approval.	The Regional Reliability Organization distributed the documentation more than 30 but less than or equal to 37 calendar days following approval.	The Regional Reliability Organization made the distribution more than 37 but less than or equal to 51 calendar days following approval.	The Regional Reliability Organization made the distribution more than 51 but less than or equal to 58 calendar days following approval.	The Regional Reliability Organization failed to make the distribution more than 58 calendar days following approval.
MOD-016-1.1	R3.	The Planning Authority shall distribute its documentation required in R1 for reporting customer data and any changes to that documentation, to its Transmission Planners and	The responsible entity failed to distribute its documentation required in Requirement R1 and	The responsible entity failed to distribute its documentation required in	The responsible entity failed to distribute its documentation required in Requirement R1 and any changes to that	The responsible entity failed to distribute its documentation as specified in Requirement R1 to

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Load-Serving Entities that work within its Planning Authority Area.	any changes to that documentation to 5% or less of all Transmission Planners and Load-Serving Entities that work within its Region. OR The responsible entity distributed the documentation more than 30 calendar days but less than or equal to 40 calendar days following approval.	Requirement R1 and any changes to that documentation to more than 5% up to (and including) 10% of all Transmission Planners and Load-Serving Entities that work within its Region. OR The responsible entity made the distribution more than 40 calendar days but less than or equal to 50 calendar days following approval.	documentation to more than 10% up to (and including) 15% of all Transmission Planners and Load-Serving Entities that work within its Region. OR The responsible entity made the distribution more than 50 calendar days but less than or equal to 60 calendar days following approval.	more than 15% of all Transmission Planners and Load-Serving Entities that work within its Region. OR The responsible entity failed to make the distribution more than 60 calendar days following approval.
MOD-016-1.1	R3.1.	The Planning Authority shall make this distribution within 30 calendar days of approval.	N/A	N/A	N/A	N/A
MOD-017-0.1	R1.	The Load-Serving Entity, Planning Authority, and Resource Planner shall each provide the following information annually on an aggregated Regional, subregional, Power Pool, individual system, or Load-Serving Entity basis to NERC, the Regional Reliability Organizations, and any other entities specified by the documentation in Standard MOD-016-1_R 1.	The responsible entity failed to provide one (1) of the elements of information as specified in R1.1, R1.2, R1.3 or R1.4 on an annual basis.	The responsible entity failed to provide two (2) of the elements of information as specified in R1.1, R1.2, R1.3 or R1.4 on an annual basis.	The responsible entity failed to provide three (3) of the elements of information as specified in R1.1, R1.2, R1.3 or R1.4 on an annual basis.	The responsible entity failed to provide all of the elements of information as specified in R1.1, R1.2, R1.3 and R1.4 on an annual basis.
MOD-017-0.1	R1.1.	Integrated hourly demands in megawatts (MW) for the prior year.	N/A	N/A	N/A	N/A
MOD-017-0.1	R1.2.	Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.	N/A	N/A	N/A	N/A

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
MOD-017-0.1	R1.3.	Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.	N/A	N/A	N/A	N/A
MOD-017-0.1	R1.4.	Annual Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for at least five years and up to ten years into the future, as requested.	N/A	N/A	N/A	N/A
MOD-018-0	R1.	The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner's report of actual and forecast demand data (reported on either an aggregated or dispersed basis) shall:	N/A	The responsible entity's report failed to include one (1) of the items as specified in R1.1, R1.2, or R1.3.	The responsible entity's report failed to include two (2) of the items as specified in R1.1, R1.2, or R1.3.	The responsible entity's report failed to include any of the items as specified in R1.1, R1.2, and R1.3.
MOD-018-0	R1.1.	Indicate whether the demand data of nonmember entities within an area or Regional Reliability Organization are included, and	N/A	N/A	N/A	N/A
MOD-018-0	R1.2.	Address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and Net Energy for Load.	N/A	N/A	N/A	N/A
MOD-018-0	R1.3.	Items (MOD-018-0_R 1.1) and (MOD-018-0_R 1.2) shall be addressed as described in the reporting procedures developed for Standard MOD-016-1_R 1.	N/A	N/A	N/A	N/A
MOD-018-0	R2.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each report data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner on request (within 30 calendar days).	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner reported the data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner reported the data associated with Reliability Standard MOD-018-0_R1 to	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner reported the data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner failed to report the data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner more than 30 but less than or equal to 45 calendar days following the request.	NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner more than 45 but less than or equal to 60 calendar days following the request.	Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner more than 60 but less than or equal to 75 calendar days following the request.	Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner more than 75 calendar days following the request.
MOD-019-0.1	R1.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-0_R 1.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner failed to provide annually less than or equal to 25% of the interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner failed to provide annually greater than 25% but less than or equal to 50% of the interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner failed to provide annually greater than 50% but less than or equal to 75% of the interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner failed to provide annually greater than 75% of the interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			MOD-016-0_R 1.	Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-0_R1.	MOD-016-0_R1.	MOD-016-0_R1.
MOD-020-0	R1.	The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make known its amount of interruptible demands and Direct Control Load Management (DCLM) to Transmission Operators, Balancing Authorities, and Reliability Coordinators on request within 30 calendar days.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner made known its amount of interruptible demands and Direct Control Load Management (DCLM) more than 30 but less than 45 calendar days following the request from Transmission Operators, Balancing Authorities, and Reliability Coordinators.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner made known its amount of interruptible demands and Direct Control Load Management (DCLM) more than 45 but less than 60 calendar days following the request from Transmission Operators, Balancing Authorities, and Reliability Coordinators.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner made known its amount of interruptible demands and Direct Control Load Management (DCLM) more than 60 but less than 75 calendar days following the request from Transmission Operators, Balancing Authorities, and Reliability Coordinators.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner failed to make known its amount of interruptible demands and Direct Control Load Management (DCLM) more than 75 calendar days following the request from Transmission Operators, Balancing Authorities, and Reliability Coordinators.
MOD-021-1	R1.	The Load-Serving Entity, Transmission Planner and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed.	Load-Serving Entity, Transmission Planner, and Resource Planner's forecasts document how the Demand and energy effects of DSM programs but failed to document how one (1)	Load-Serving Entity, Transmission Planner, and Resource Planner's forecasts document how the Demand and energy effects of DSM programs but failed to	Load-Serving Entity, Transmission Planner, and Resource Planner's forecasts document how the Demand and energy effects of DSM programs but failed to document how three (3) of the following	Load-Serving Entity, Transmission Planner, and Resource Planner's forecasts failed to document how the Demand and energy effects of DSM programs are addressed.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			of the following elements of the Demand and energy effects of DSM programs are addressed: conservation, time-of-use rates, interruptible Demands or Direct Control Load Management.	document how two (2) of the following elements of the Demand and energy effects of DSM programs are addressed: conservation, time-of-use rates, interruptible Demands or Direct Control Load Management.	elements of the Demand and energy effects of DSM programs are addressed: conservation, time-of-use rates, interruptible Demands or Direct Control Load Management.	
MOD-021-1	R2.	The Load-Serving Entity, Transmission Planner and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R1.	N/A	N/A	N/A	The Load-Serving Entity, Transmission Planner, and Resource Planner failed to include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R 1.
MOD-021-1	R3.	The Load-Serving Entity, Transmission Planner and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on request (within 30 calendar days).	The Load-Serving Entity, Transmission Planner, and Resource Planner provided documentation on the treatment of its DSM programs more than 30 but less than 45 calendar days	The Load-Serving Entity, Transmission Planner, and Resource Planner provided documentation on the treatment of its DSM programs more than 45 but	The Load-Serving Entity, Transmission Planner, and Resource Planner provided documentation on the treatment of its DSM programs more than 60 but less than 75 calendar days following	The Load-Serving Entity, Transmission Planner, and Resource Planner failed to provide documentation on the treatment of its DSM programs more than 75 calendar days following the request

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			following the request from NERC.	less than 60 calendar days following the request from NERC.	the request from NERC.	from NERC.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
NUC-001-2	R1.	The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt.	The Nuclear Plant Generator Operator provided the NPIR's to the applicable entities but did not verify receipt.	The Nuclear Plant Generator Operator did not provide the proposed NPIR to one of the applicable entities.	The Nuclear Plant Generator Operator did not provide the proposed NPIR's to two of the applicable entities.	The Nuclear Plant Generator Operator did not provide the proposed NPIR's to more than two of applicable entities.
NUC-001-2	R2.	The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs.	N/A	N/A	N/A	The Nuclear Plant Generator Operator or the applicable Transmission Entity does not have in effect one or more agreements that include mutually agreed to NPIRs and document the implementation of the NPIRs.
NUC-001-2	R3.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator.	N/A	The responsible entity incorporated the NPIRs into its planning analyses but did not communicate the results to the Nuclear Plant Generator Operator.	N/A	The responsible entity did not incorporate the NPIRs into its planning analyses of the electric system.
NUC-001-2	R4.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall:	The applicable Transmission Entity failed to incorporate one or more applicable NPIRs into their operating analyses.	The applicable Transmission Entity failed to incorporate any NPIRs into their operating analyses OR did not inform NPG operator when their ability of	The applicable Transmission Entity failed to operate the system to meet the NPIRs	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assess the operation of the electric system affecting the NPIRs was lost.		
NUC-001-2	R4.1	Incorporate the NPIRs into their operating analyses of the electric system.	N/A	N/A	N/A	N/A
NUC-001-2	R4.2	Operate the electric system to meet the NPIRs.	N/A	N/A	N/A	N/A
NUC-001-2	R4.3	Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.	N/A	N/A	N/A	N/A
NUC-001-2	R5.	The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard.	N/A	N/A	N/A	The Nuclear Plant Generator Operator failed to operate per the Agreements developed in accordance with this standard.
NUC-001-2	R6.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs.	The Nuclear Operator or Transmission Entity failed to coordinate outages or maintenance activities in accordance with one or more of the administrative elements within the agreements.	The Nuclear Operator or Transmission Entity failed to provide outage or maintenance schedules to the appropriate parties as described in the agreement or on a time period consistent with the agreements.	The Nuclear Operator or Transmission Entity failed to coordinate one or more outages or maintenance activities in accordance the requirements of the agreements.	N/A
NUC-001-2	R7.	Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design,	The Nuclear Plant Generator Operator did not inform the applicable Transmission Entities	The Nuclear Plant Generator Operator did not inform the applicable Transmission	The Nuclear Plant Generator Operator did not inform the applicable Transmission Entities	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	of proposed changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	Entities of actual changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	of actual changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that directly impact the ability of the electric system to meet the NPIRs.	
NUC-001-2	R8.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	The applicable Transmission Entities did not inform the Nuclear Plant Generator Operator of proposed changes to transmission system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	The applicable Transmission Entities did not inform the Nuclear Plant Generator Operator of actual changes to transmission system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	The applicable Transmission Entities did not inform the Nuclear Plant Generator Operator of actual changes to transmission system design, configuration, operations, limits, protection systems, or capabilities that directly impacts the ability of the electric system to meet the NPIRs.	N/A
NUC-001-2	R9.	The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2:	The agreement identified in R2. between the Nuclear Plant Generator Operator and the applicable Transmission Entities is missing one or more sub-components of R9.1.	The agreement identified in R2. between the Nuclear Plant Generator Operator and the applicable Transmission Entities is missing from one to five of the combined sub-	The agreement identified in R2. between the Nuclear Plant Generator Operator and the applicable Transmission Entities is missing from six to ten of the combined sub-components in R9.2,	The agreement identified in R2. between the Nuclear Plant Generator Operator and the applicable Transmission Entities is missing eleven or more of the combined sub-components in

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			(Retired)	components in R9.2, R9.3 and R9.4.	R9.3 and R9.4.	R9.2, R9.3 and R9.4.
NUC-001-2	R9.1 (Retired)	Administrative elements:	N/A	N/A	N/A	N/A
NUC-001-2	R9.1.1 (Retired)	Definitions of key terms used in the agreement.	N/A	N/A	N/A	N/A
NUC-001-2	R9.1.2 (Retired)	Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs.	N/A	N/A	N/A	N/A
NUC-001-2	R9.1.3 (Retired)	A requirement to review the agreement(s) at least every three years.	N/A	N/A	N/A	N/A
NUC-001-2	R9.1.4 (Retired)	A dispute resolution mechanism.	N/A	N/A	N/A	N/A
NUC-001-2	R9.2	Technical requirements and analysis:	N/A	N/A	N/A	N/A
NUC-001-2	R9.2.1	Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.	N/A	N/A	N/A	N/A
NUC-001-2	R9.2.2	Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.	N/A	N/A	N/A	N/A
NUC-001-2	R9.2.3	Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.	N/A	N/A	N/A	N/A
NUC-001-2	R9.3	Operations and maintenance coordination:	N/A	N/A	N/A	N/A
NUC-001-2	R9.3.1	Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and	N/A	N/A	N/A	N/A

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		responsibilities for operational control coordination and maintenance of these facilities.				
NUC-001-2	R9.3.2	Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.	N/A	N/A	N/A	N/A
NUC-001-2	R9.3.3	Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.	N/A	N/A	N/A	N/A
NUC-001-2	R9.3.4	Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.	N/A	N/A	N/A	N/A
NUC-001-2	R9.3.5	Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power.	N/A	N/A	N/A	N/A
NUC-001-2	R9.3.6	Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity's plan.	N/A	N/A	N/A	N/A
NUC-001-2	R9.3.7	Coordination of the NPIRs with transmission system Special Protection Systems and underfrequency and undervoltage load shedding programs.	N/A	N/A	N/A	N/A
NUC-001-2	R9.4	Communications and training:	N/A	N/A	N/A	N/A

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
NUC-001-2	R9.4.1	Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time requirements, and definitions of terms.	N/A	N/A	N/A	N/A
NUC-001-2	R9.4.2	Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.	N/A	N/A	N/A	N/A
NUC-001-2	R9.4.3	Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.	N/A	N/A	N/A	N/A
NUC-001-2	R9.4.4	Provisions for supplying information necessary to report to government agencies, as related to NPIRs.	N/A	N/A	N/A	N/A
NUC-001-2	R9.4.5	Provisions for personnel training, as related to NPIRs.	N/A	N/A	N/A	N/A

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
PER-001-0.2	R1.	Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.	N/A	N/A	The Transmission Operator or Balancing Authority failed to demonstrate that it communicated to its operating personnel their responsibility or their authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.	The Transmission Operator or Balancing Authority failed to demonstrate that it communicated to its operating personnel their responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.
PER-002-0	R1.	Each Transmission Operator and Balancing Authority shall be staffed with adequately trained operating personnel.	The responsible entity failed to staff 5% or less with adequately trained operating personnel.	The responsible failed to staff more than 5% up to (and including) 10% with adequately trained operating personnel.	The responsible entity failed to staff more than 10% up to (and including) 15% with adequately trained operating personnel.	The responsible entity failed to staff more than 15% with adequately trained operating personnel.
PER-002-0	R2.	Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:	The responsible entity did not train operating personnel for positions described in R2.1 or R2.2, affecting 5% or less of its operating personnel.	The responsible entity did not train operating personnel for positions described in R2.1 or R2.2, affecting more than 5% up to (and including) 10% of its operating personnel.	The responsible entity did not train operating personnel for positions described in R2.1 or R2.2, affecting more than 10% up to (and including) 15% of its operating personnel.	The responsible entity did not train operating personnel for positions described in R2.1 or R2.2, affecting more than 15% of its operating personnel.
PER-002-0	R2.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.	N/A	N/A	N/A	N/A
PER-002-0	R2.2.	Positions directly responsible for complying with NERC standards.	N/A	N/A	N/A	N/A

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
PER-002-0	R3.	For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:	The applicable entity did not comply with one of the four required elements.	The applicable entity did not comply with two of the four required elements.	The applicable entity did not comply with three of the four required elements.	The applicable entity did not comply with any of the four required elements.
PER-002-0	R3.1.	A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions for the Transmission Operator and Balancing Authority operating positions.	The responsible entity's training program objectives were incomplete (e.g. The responsible entity failed to define training program objectives for less than 25% of the applicable BA and TOP NERC and Regional Reliability Organizations standards, entity operating procedures, and regulatory requirements.)	The responsible entity's training program objectives were incomplete (e.g. The responsible entity failed to define training program objectives for 25% or more but less than 50% of the applicable BA & TOP NERC and Regional Reliability Organizations standards, entity operating procedures, and regulatory requirements.)	The responsible entity's training program objectives were incomplete (e.g. The responsible entity failed to define training program objectives for 50% or more but less than 75% of the applicable BA & TOP NERC and Regional Reliability Organizations standards, entity operating procedures, and regulatory requirements.)	The responsible entity's training program objectives were incomplete (e.g. The responsible entity failed to define training program objectives for 75% or more of the applicable BA & TOP NERC and Regional Reliability Organizations standards, entity operating procedures, and regulatory requirements.)
PER-002-0	R3.2.	The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan shall address knowledge and competencies required for reliable system operations.	The responsible entity does not have a plan for continuing training of operating personnel. OR The responsible entity does not have a plan for initial training of operating personnel. OR The responsible entity's plan does not address the	The responsible entity does not have a plan for continuing training of operating personnel. OR The responsible entity does not have a plan for initial training of operating personnel. AND The responsible entity's plan does not address the	The responsible entity does not have a plan for continuing training of operating personnel. AND The responsible entity does not have a plan for initial training of operating personnel. OR The responsible entity's plan does not address the knowledge and competencies required for reliable system operations.	The responsible entity does not have a plan for continuing training of operating personnel. AND The responsible entity does not have a plan for initial training of operating personnel. AND The responsible entity's plan does not address the knowledge and competencies required for reliable system operations.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			knowledge and competencies required for reliable system operations.	knowledge and competencies required for reliable system operations.		
PER-002-0	R3.3.	The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency.	The responsible entity has produced the training program with more than 75% but less than 100% of operating personnel provided with training time.	The responsible entity has produced the training program with more than 50% but less than or equal to 75% of operating personnel provided with training time.	The responsible entity has produced the training program with more than 25% but less than or equal to 50% of operating personnel provided with training time.	The responsible entity has produced the training program with more than or equal to 0% but less than or equal to 25% of operating personnel provided with training time.
PER-002-0	R3.4.	Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.	N/A	The responsible entity has produced the training program with training staff identified that lacks knowledge of system operations. OR The responsible entity has produced the training program with training staff identified that lacks instructional capabilities.	The responsible entity has produced the training program with training staff identified that lacks knowledge of system operations. AND The responsible entity has produced the training program with training staff identified that lacks instructional capabilities.	The responsible entity has produced the training program with no training staff identified.
PER-003-1	R1.	Each Reliability Coordinator shall staff its Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator				The Reliability Coordinator failed to staff each Real-time operating position performing Reliability Coordinator reliability-related

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		certificate:				tasks with a System Operator having a valid NERC certificate as defined in Requirement R1.
PER-003-1	R2.	Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates:				The Transmission Operator failed to staff each Real-time operating position performing Transmission Operator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R2, Part 2.2.
PER-003-1	R3.	Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates:				The Balancing Authority failed to staff each Real-time operating position performing Balancing Authority reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R3, Part 3.2.

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PER-004-1	R3.	Reliability Coordinator operating personnel shall have a comprehensive understanding of the Reliability Coordinator Area and interactions with neighboring Reliability Coordinator Areas.	5% or less of the Reliability Coordinator operating personnel did not have a comprehensive understanding of the Reliability Coordinator Area and interactions with neighboring Reliability Coordinator Areas.	More than 5% up to (and including) 10% of the Reliability Coordinator operating personnel did not have a comprehensive understanding of the Reliability Coordinator Area and interactions with neighboring Reliability Coordinator Areas.	More than 10% up to (and including) 15% of the Reliability Coordinator operating personnel did not have a comprehensive understanding of the Reliability Coordinator Area and interactions with neighboring Reliability Coordinator Areas.	More than 15% of the Reliability Coordinator operating personnel did not have a comprehensive understanding of the Reliability Coordinator Area and interactions with neighboring Reliability Coordinator Areas.
PER-004-1	R4.	Reliability Coordinator operating personnel shall have an extensive understanding of the Balancing Authorities, Transmission Operators, and Generation Operators within the Reliability Coordinator Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and operational restrictions.	5% or less of the Reliability Coordinator operating personnel did not have an extensive understanding of the Balancing Authorities, Transmission Operators, and Generation Operators within the Reliability Coordinator Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and	More than 5% up to (and including) 10% of the Reliability Coordinator operating personnel did not have an extensive understanding of the Balancing Authorities, Transmission Operators, and Generation Operators within the Reliability Coordinator Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment	More than 10% up to (and including) 15% of the Reliability Coordinator operating personnel did not have an extensive understanding of the Balancing Authorities, Transmission Operators, and Generation Operators within the Reliability Coordinator Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and operational restrictions.	More than 15% of the Reliability Coordinator operating personnel did not have an extensive understanding of the Balancing Authorities, Transmission Operators, and Generation Operators within the Reliability Coordinator Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and operational restrictions.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			operational restrictions.	capabilities, and operational restrictions.		

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-001-1	R1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	N/A	N/A	The responsible entity failed to be familiar with the limitations of protection system schemes applied in its area.	The responsible entity failed to be familiar with the purpose of protection system schemes applied in its area.
PRC-001-1	R2.	Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	N/A	N/A	N/A	The responsible entity failed to notify any reliability entity of relay or equipment failures.
PRC-001-1	R2.1.	If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.	N/A	Notification of relay or equipment failure was not made to the Transmission Operator and Host Balancing Authority, but corrective action was taken.	Notification of relay or equipment failure was made to the Transmission Operator and Host Balancing Authority, but corrective action was not taken.	Notification of relay or equipment failure was not made to the Transmission Operator and Host Balancing Authority, and corrective action was not taken.
PRC-001-1	R2.2.	If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	N/A	Notification of relay or equipment failure was not made to the Reliability Coordinator and affected Transmission Operators and Balancing Authorities, but corrective action was taken.	Notification of relay or equipment failure was made to the Reliability Coordinator and affected Transmission Operators and Balancing Authorities, but corrective action was not taken.	Notification of relay or equipment failure was not made to the Reliability Coordinator and affected Transmission Operators and Balancing Authorities, and corrective action was not taken.
PRC-001-1	R3.	A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.	N/A	N/A	N/A	N/A

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-001-1	R3.1.	Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.	The Generator Operator failed to coordinate one new protective system or protective system change with either its Transmission Operator or its Host Balancing Authority or both.	The Generator Operator failed to coordinate two new protective systems or protective system changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate three new protective systems or protective system changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate more than three new protective systems or protective system changes with its Transmission Operator or its Host Balancing Authority, or both.
PRC-001-1	R3.2.	Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	The Transmission Operator failed to coordinate one new protective system or protective system change with neighboring Transmission Operators or Balancing Authorities or both.	The Transmission Operator failed to coordinate two new protective systems or protective system changes with neighboring Transmission Operators or Balancing Authorities or both.	The Transmission Operator failed to coordinate three new protective systems or protective system changes with neighboring Transmission Operators or Balancing Authorities or both.	The Transmission Operator failed to coordinate more than three new protective systems or protective system changes with neighboring Transmission Operators or Balancing Authorities or both.
PRC-001-1	R4.	Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with one of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with two of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with three of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with three or more of its neighboring Generator Operators, Transmission Operators, and Balancing Authorities.
PRC-001-1	R5.	A Generator Operator or Transmission Operator shall coordinate changes in	N/A	N/A	The Generator Operator failed to notify its	The Generator Operator failed to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		generation, transmission, load or operating conditions that could require changes in the protection systems of others:			Transmission Operator at all of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems. (R5.1) OR The Transmission Operator failed to notify neighboring Transmission Operators at all of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems. (R5.2)	notify its Transmission Operator at all of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems. (R5.1) AND The Transmission Operator failed to notify neighboring Transmission Operators at all of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems. (R5.2)
PRC-001-1	R5.1.	Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.	N/A	N/A	N/A	N/A
PRC-001-1	R5.2.	Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.	N/A	N/A	N/A	N/A
PRC-001-1	R6.	Each Transmission Operator and Balancing Authority shall monitor the status of each	N/A	N/A	The responsible entity monitored the status of	The responsible entity failed to monitor the

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.			each Special Protection System in its area but notification of a change in status of a Special Protection System was not made to the affected Transmission Operators and Balancing Authorities.	status of each Special Protection System in its area, and did not notify affected Transmission Operators and Balancing Authorities of each change in status.
PRC-002-NPCC-01	R1.	Each Transmission Owner and Generator Owner shall provide Sequence of Event (SOE) recording capability by installing Sequence of Event recorders or as part of another device, such as a Supervisory Control And Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control System (DCS) or part of Fault recording equipment. This capability shall: [See standard for requirements of SOE recording capability]	The Transmission Owner or Generator Owner provided the Sequence of Event recording capability meeting the bulk of R1 but missed up to and including 10% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	The Transmission Owner or Generator Owner provided the Sequence of Event recording capability meeting the bulk of R1 but missed more than 10% and up to and including 20% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	The Transmission Owner or Generator Owner provided the Sequence of Event recording capability meeting the bulk of R1 but missed more than 20% and up to and including 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	The Transmission Owner or Generator Owner provided the Sequence of Event recording capability meeting the bulk of R1 but missed more than 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.
PRC-002-NPCC-01	R2.	Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: [See standard for list of elements]	The Transmission Owner provided the Fault recording capability meeting the bulk of R2 but missed up to and including 10% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	The Transmission Owner provided the Fault recording capability meeting the bulk of R2 but missed more than 10% and up to and including 20% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the	The Transmission Owner provided the Fault recording capability meeting the bulk of R2 but missed more than 20% and up to and including 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	The Transmission Owner provided the Fault recording capability meeting the bulk of R2 but missed more than 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.

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				criteria listed in 2.1 through 2.6.		
PRC-002-NPCC-01	R3.	Each Transmission Owner shall have Fault recording capability that determines the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements.	N/A	N/A	N/A	The Transmission Owner failed to provide fault recording capability that determines the current zero time for loss of transmission Elements.
PRC-002-NPCC-01	R4.	Each Generator Owner shall provide Fault recording capability for Generating Plants at and above 200 MVA Capacity and connected through a generator step up (GSU) transformer to a Bulk Electric System Element unless Fault recording capability is already provided by the Transmission Owner.	The Generator Owner failed to provide Fault recording capability at up to and including 10% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	The Generator Owner failed to provide Fault recording capability at more than 10% and up to and including 20% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	The Generator Owner failed to provide Fault recording capability at more than 20% and up to 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	The Generator Owner failed to provide Fault recording capability at more than 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.
PRC-002-NPCC-01	R5.	Each Transmission Owner and Generator Owner shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following: [See standard for list]	The Transmission Owner or Generator Owner failed to record for the Faults up to and including 10% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters	The Transmission Owner or Generator Owner failed to record for the Faults more than 10% and up to and including 20% of the total set of parameters, which is the product of the total number of monitored Elements	The Transmission Owner or Generator Owner failed to record for the Faults more than 20% and up to and including 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters	The Transmission Owner or Generator Owner failed to record for the Faults more than 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in

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			listed in 5.1 through 5.5.	and the number of parameters listed in 5.1 through 5.5.	listed in 5.1 through 5.5.	5.1 through 5.5.
PRC-002-NPCC-01	R6.	Each Transmission Owner and Generator Owner shall provide Fault recording with the following capabilities: [See standard for list of capabilities]	The Transmission Owner or Generator Owner failed to provide Fault recording capability for up to and including 10% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for up to 2 locations.	The Transmission Owner or Generator Owner failed to provide Fault recording capability for more than 10% and up to and including 20% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than two (2) and up to and including five (5) locations.	The Transmission Owner or Generator Owner failed to provide Fault recording capability for more than 20% and up to and including 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than five (5) and up to and including ten (10) locations.	The Transmission Owner or Generator Owner failed to provide Fault recording capability for more than 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than ten (10) locations.
PRC-002-NPCC-01	R7.	Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance Recording (DDR) capability that: [See standard for futher requirements]	The Reliability Coordinator failed to establish its area's requirements for up to and including 10% of the required DDR	The Reliability Coordinator failed to establish its area's requirements for more than 10% and up to and including	The Reliability Coordinator failed to establish its area's requirements for more than 20% and up to and including 30% of the	The Reliability Coordinator failed to establish its area's requirements for more than 30% of the required DDR

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			coverage for its area as per 7.1and 7.2.	20% of the required DDR coverage for its area as per 7.1 and 7.2.	required DDR coverage for its area as per 7.1 and 7.2.	coverage for its area as per 7.1 and 7.2.
PRC-002-NPCC-01	R8.	Each Reliability Coordinator shall specify that DDRs installed, after the approval of this standard, function as continuous recorders.	N/A	N/A	N/A	The Reliability Coordinator failed to specify that DDRs installed function as continuous recorders.
PRC-002-NPCC-01	R9.	Each Reliability Coordinator shall specify that DDRs are installed with the following capabilities: [See standard for list of capabilities]	N/A	N/A	N/A	The Reliability Coordinator failed to specify that DDRs are installed without the capabilities listed in 9.1 through 9.3.
PRC-002-NPCC-01	R10.	Each Reliability Coordinator shall establish requirements such that the following quantities are monitored or derived where DDRs are installed: [See standard for quantities]	N/A	N/A	N/A	The Reliability Coordinator failed to ensure that the quantities listed in 10.1 through 10.5 are monitored or derived where DDRs are installed.
PRC-002-NPCC-01	R11.	Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10, and report this to the Regional Entity (RE) upon request.	The Reliability Coordinator failed to document and report to the Regional Entity upon request additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10 for up to two (2) facilities within the Reliability Coordinator's area	The Reliability Coordinator failed to document and report to the Regional Entity upon request additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10 for more than two (2) and up to five (5)	The Reliability Coordinator failed to document and report to the Regional Entity upon request additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10 for more than five (5) and up to ten (10) facilities within the Reliability Coordinator's area that have a DDR.	The Reliability Coordinator failed to document and report to the Regional Entity upon request additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10 for more than ten (10) facilities within the Reliability

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			that have a DDR.	facilities within the Reliability Coordinator's area that have a DDR.		Coordinator's area that have a DDR.
PRC-002-NPCC-01	R12.	Each Reliability Coordinator shall specify its DDR requirements including the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners.	N/A	N/A	N/A	The Reliability Coordinator failed to specify to the Transmission Owners and Generator Owners its DDR requirements including the DDR setting triggers established in R9 but missed established setting triggers.
PRC-002-NPCC-01	R13.	Each Transmission Owner and Generator Owner that receives a request from the Reliability Coordinator to install a DDR shall acquire and install the DDR in accordance with R12. Reliability Coordinators, Transmission Owners, and Generator Owners shall mutually agree on an implementation schedule.	The Transmission Owner or Generator Owner failed to comply with the Reliability Coordinator's request installing the DDR in accordance with R12 for up to and including 10% of the requirement set of the Reliability Coordinator's request to install DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	The Transmission Owner or Generator Owner failed to comply with the Reliability Coordinator's request installing the DDR in accordance with R12 for more than 10% and up to 20% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	The Transmission Owner or Generator Owner failed to comply with the Reliability Coordinator's request installing the DDR in accordance with R12 for more than 20% and up to 30% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	The Transmission Owner or Generator Owner failed to comply with the Reliability Coordinator's request installing the DDR in accordance with R12 for more than 30% of the requirement set requested by the Reliability Coordinator and installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR OR

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						The Reliability Coordinator, Transmission Owners, and Generator Owners failed to mutually agree on an implementation schedule.
PRC-002-NPCC-01	R14.	Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: [See standard for list of inclusions]	The Transmission Owner or Generator Owner established a maintenance and testing program for stand alone DME but provided incomplete data for any one (1) of 14.1 through 14.7.	The Transmission Owner or Generator Owner established a maintenance and testing program for stand alone DME but provided incomplete data for more than one (1) and up to and including three (3) of 14.1 through 14.7.	The Transmission Owner or Generator Owner established a maintenance and testing program for stand alone DME but provided incomplete data for more than three (3) and up to and including six (6) of 14.1 through 14.7.	The Transmission Owner or Generator Owner did not establish any maintenance and testing program for DME; OR The Transmission Owner or Generator Owner established a maintenance and testing program for DME but did not provide any data that meets all of 14.1 through 14.7.
PRC-002-NPCC-01	R15.	Each Reliability Coordinator, Transmission Owner and Generator Owner shall share data within 30 days upon request. Each Reliability Coordinator, Transmission Owner, and Generator Owner shall provide recorded disturbance data from DMEs within 30 days of receipt of the request in each of the following cases: [See standard for the two cases]	The Reliability Coordinator, Transmission Owner or Generator Owner provided recorded disturbance data from DMEs but was late for up to and including fifteen (15) days in	The Reliability Coordinator, Transmission Owner or Generator Owner provided recorded disturbance data from DMEs but was late for more than fifteen (15) days but	The Reliability Coordinator, Transmission Owner or Generator Owner provided recorded disturbance data from DMEs but was late for more than 30 days but less than and including	The Reliability Coordinator, Transmission Owner or Generator Owner provided recorded disturbance data from DMEs but was late for more than forty-five (45) days in meeting

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			meeting the requests of an entity, or entities in 15.1, or 15.2.	less than and including thirty (30) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	the requests of an entity, or entities in 15.1 or 15.2.
PRC-002-NPCC-01	R16.	Each Reliability Coordinator, Transmission Owner and Generator Owner shall submit the data files conforming to the following format requirements: [See standard for format requirements]	The Reliability Coordinator, Transmission Owner or Generator Owner failed to submit up to and including two (2) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	The Reliability Coordinator, Transmission Owner or Generator Owner failed to submit more than two (2) and up to and including five (5) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	The Reliability Coordinator, Transmission Owner or Generator Owner failed to submit more than five (5) and up to and including ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	The Reliability Coordinator, Transmission Owner or Generator Owner failed to submit more than ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.
PRC-002-NPCC-01	R17.	Each Reliability Coordinator, Transmission Owner and Generator Owner shall maintain, record and provide to the Regional Entity (RE), upon request, the following data on the DMEs installed to meet this standard: [See standard for types of data]	The Reliability Coordinator, Transmission Owner or Generator Owner failed to maintain or provide to the Regional Entity, upon request up to and including two (2) of the items in 17.1 through 17.8.	The Reliability Coordinator, Transmission Owner or Generator Owner failed to maintain or provide to the Regional Entity, upon request more than two (2) and up to and including four (4) of the items in 17.1 to 17.8.	The Reliability Coordinator, Transmission Owner or Generator Owner failed to maintain or provide to the Regional Entity, upon request more than four (4) and up to and including six (6) of the items in 17.1 through 17.8.	The Reliability Coordinator, Transmission Owner or Generator Owner failed to maintain or provide to the Regional Entity, upon request more than six (6) of the items in 17.1 through 17.8.
PRC-004-1a	R1.	The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid	N/A	The responsible entity provided evidence of analyzing a Misoperation but the documentation and	N/A	The responsible entity did not perform an analysis of a Misoperation.

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		future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.		implementation of the associated Corrective Action Plan was not provided.		
PRC-004-1a	R2.	The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.	N/A	The Generator Owner provided evidence of analyzing a Misoperation but the documentation and implementation of the associated Corrective Action Plan was not provided.	N/A	The Generator Owner did not perform an analysis of a Misoperation.
PRC-004-1a	R3.	The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.	The responsible entity provided its Regional Reliability Organization with documentation of its Misoperations analyses and its Corrective Action Plans, but did not provide these according to the Regional Reliability Organization's procedures.	N/A	The responsible entity provided its Regional Reliability Organization with documentation of its Misoperations analyses but did not provide its Corrective Action Plans.	The responsible entity did not provide its Regional Reliability Organization with documentation of its Misoperations analyses and did not provide its Corrective Action Plans.
PRC-004-2a	R1.	The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature	Documentation of Misoperations is complete, but documentation of Corrective Action Plans is incomplete.	Documentation of Misoperations is incomplete, and documentation of Corrective Action Plans is incomplete.	Documentation of Misoperations is incomplete, and there are no associated Corrective Action Plans.	Misoperations have not been analyzed

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		according to the Regional Entity's procedures.				
PRC-004-2a	R2.	The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	Documentation of Misoperations is complete, but documentation of Corrective Action Plans is incomplete.	Documentation of Misoperations is incomplete, and documentation of Corrective Action Plans is incomplete.	Documentation of Misoperations is incomplete, and there are no associated Corrective Action Plans.	Misoperations have not been analyzed
PRC-004-2a	R3.	The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.	The responsible entity provided its Regional Reliability Organization with documentation of its Misoperations analyses and its Corrective Action Plans, but did not provide these according to the Regional Reliability Organization's procedures.	N/A	The responsible entity provided its Regional Reliability Organization with documentation of its Misoperations analyses but did not provide its Corrective Action Plans.	The responsible entity did not provide its Regional Reliability Organization with documentation of its Misoperations analyses and did not provide its Corrective Action Plans.
PRC-004-WECC-1	R1.	System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations.	System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days.	System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days.	System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days.	System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days.
PRC-004-	R1.1.	System Operators shall review all tripping of transmission elements and RAS operations to				

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
WECC-1		identify apparent Misoperations within 24 hours.				
PRC-004-WECC-1	R1.2.	System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.				
PRC-004-WECC-1	R2.	Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the Transmission Owner or Generator Owner identifies the Misoperation:				
PRC-004-WECC-1	R2.1.	If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the	The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements	The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Transmission Owners' and Generator Owners' discretion.	within 24 hours.	perform the requirements within 28 hours.	32 hours.	
PRC-004-WECC-1	R2.2.	If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following.				
PRC-004-WECC-1	R2.2.1.	Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.	The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.	The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.
PRC-004-WECC-1	R2.2.2.	The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				within 28 business days.		
PRC-004-WECC-1	R2.3.	If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.
PRC-004-WECC-1	R2.3.1.	When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.				
PRC-004-WECC-1	R2.3.2.	When FERAS is not available, then				
PRC-004-WECC-1	R2.3.2.1.	The Generator Owners shall adjust generation to a reliable operating level, or				
PRC-004-WECC-1	R2.3.2.2.	Transmission Operators shall adjust the SOL and operate the facilities within established limits.				
PRC-004-WECC-1	R2.4.	If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or	The Transmission Owner and Generator Owner did not perform the required	The Transmission Owner and Generator Owner did not perform the	The Transmission Owner and Generator Owner did not perform the required repairs,	The Transmission Owner and Generator Owner did not perform the required

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.	repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days.	required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days.	replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days.	repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days.
PRC-004-WECC-1	R2.4.1.	Transmission Owners or Generator Owners shall repair or replace any Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or				
PRC-004-WECC-1	R2.4.2.	Transmission Owners or Generator Owners shall remove from service the associated Element or RAS.				
PRC-004-WECC-1	R3.	Transmission Owners and Generation Owners shall submit Misoperation incident reports to WECC within 10 business days for the following.				
PRC-004-WECC-1	R3.1.	Identification of a Misoperation of a Protection System and/or RAS,	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days.

Complete Violation Severity Level Matrix (PRC)
Encompassing All Commission-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-004-WECC-1	R3.2.	Completion of repairs or the replacement of Protection System and/or RAS that misoperated.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion.
PRC-005-1b	R1.	Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:	N/A	The responsible entity-had a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES, but the summary of maintenance and testing procedures was missing or incomplete. (R1.2)	The responsible entity had a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES, but the maintenance and testing intervals and their basis were missing or incomplete. (R1.1)	The responsible entity failed to have Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES.
PRC-005-1b	R1.1.	Maintenance and testing intervals and their basis.	N/A	N/A	N/A	N/A
PRC-005-1b	R1.2.	Summary of maintenance and testing procedures.	N/A	N/A	N/A	N/A
PRC-005-1b	R2.	Each Transmission Owner and any Distribution Provider that owns a	The responsible entity provided	Evidence Protection System devices were	Evidence Protection System devices were	Evidence Protection System devices were

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:	documentation of its Protection System maintenance and testing program more than 30 calendar days following a request from its Regional Reliability Organization and/or NERC. OR Evidence Protection System devices were maintained and tested within the defined intervals (R2.1 and R2.2) was missing 5% or less of the applicable devices.	maintained and tested within the defined intervals (R2.1 and R2.2) was missing more than 5% up to (and including) 10% of the applicable devices.	maintained and tested within the defined intervals (R2.1 and R2.2) was missing more than 10% up to (and including) 15% of the applicable devices.	maintained and tested within the defined intervals (R2.1 and R2.2) was missing more than 15% of the applicable devices.
PRC-005-1b	R2.1.	Evidence Protection System devices were maintained and tested within the defined intervals.	N/A	N/A	N/A	N/A
PRC-005-1b	R2.2.	Date each Protection System device was last tested/maintained.	N/A	N/A	N/A	N/A
PRC-006-1	R1.	Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands.	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas,	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				and Regional Entity areas that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	that may form islands.	
PRC-006-1	R2.	Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[See Standard pdf for further information]*	N/A	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3. OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						program.
PRC-006-1	R3.	Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[See Standard pdf for further information]*	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).,but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area
PRC-006-1	R4.	Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines	The Planning Coordinator	The Planning Coordinator conducted and	The Planning Coordinator conducted and documented a UFLS	The Planning Coordinator

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[See Standard pdf for further information]*	conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2
PRC-006-1	R5.	Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning	N/A	N/A	N/A	The Planning Coordinator, whose area or portions of

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: • Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or • Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or • Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.				whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
PRC-006-1	R6.	Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.	N/A	N/A	N/A	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						once each calendar year, with no more than 15 months between maintenance activities.
PRC-006-1	R7.	Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.
PRC-006-1	R8.	Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.		to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
PRC-006-1	R9.	Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets.	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
PRC-006-1	R10.	Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission
PRC-006-1	R11.	Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[See Standard pdf for further information]*	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts11.1 or 11.2.	excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.
PRC-006-1	R12.	Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation.	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
PRC-006-1	R13.	Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: • Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or • Conduct an independent event assessment per Requirement R11 that	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or • Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.				areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13
PRC-006-1	R14.	Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following: *[See Standard pdf for further information]*	N/A	N/A	N/A	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the

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						items in Parts 14.1 through 14.3.
PRC-007-0	R1.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS program is consistent with its Regional Reliability Organization's UFLS program requirements.	The evaluation of the entity's UFLS program for consistency with its Regional Reliability Organization's UFLS program is incomplete or inconsistent in one or more of the Regional Reliability Organization program requirements, but is consistent with the required amount of load shedding.	The amount of load shedding is less than 95 percent of the Regional requirement in any of the load steps.	The amount of load shedding is less than 90 percent of the Regional requirement in any of the load steps.	The amount of load shedding is less than 85 percent of the Regional requirement in any of the load steps.
PRC-007-0	R2.	The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database.	The responsible entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) provided its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database but its annual update was late by 30 calendar days or less.	The responsible entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) provided its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database but its annual update was late by more than 30 calendar days but less than or equal to 40 calendar days	The responsible entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) provided its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database but its annual update was late by more than 40 calendar days but less than or equal to 50 calendar days.	The responsible entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) did not provided its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database, OR The responsible entity's annual update was late by more than 50 calendar days.

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PRC-007-0	R3.	The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).	The responsible entity has provided the documentation in more than 30 calendar days but less than or equal to 40 calendar days.	The responsible entity has provided the documentation in more than 40 calendar days but less than or equal to 50 calendar days.	The responsible entity has provided the documentation in more than 50 calendar days but less than or equal to 60 calendar days.	The responsible entity has not provided the documentation for more than 60 calendar days.
PRC-008-0	R1.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.	The UFLS equipment identification, testing schedule or maintenance schedule for the responsible entity's UFLS equipment maintenance and testing program was missing 5% or less of the applicable equipment.	The UFLS equipment identification, testing schedule, or maintenance schedule for the responsible entity's UFLS equipment maintenance and testing program was missing for more than 5% up to (and including) 10% of the applicable equipment.	The UFLS equipment identification, testing schedule, or maintenance schedule for the responsible entity's UFLS equipment maintenance and testing program was missing more than 10% up to (and including) 15% of the applicable equipment.	The responsible entity failed to implement UFLS equipment maintenance and testing program. OR The UFLS equipment identification, testing schedule, or maintenance schedule for the responsible entity's UFLS equipment maintenance and testing program was missing more than 15% of the applicable equipment.
PRC-008-0	R2.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).	The responsible entity provided documentation of its UFLS equipment maintenance and testing program more than 30 calendar days following a request from its Regional Reliability Organization and/or NERC.	Evidence UFLS equipment was maintained and tested within the defined intervals was missing for more than 5% up to (and including) 10% of the applicable devices.	Evidence UFLS equipment was maintained and tested within the defined intervals was missing for more than 10% up to (and including) 15% of the applicable devices.	Evidence UFLS equipment was maintained and tested within the defined intervals was missing for more than 15% of the applicable devices.

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			OR Evidence UFLS equipment was maintained and tested within the defined intervals was missing for 5% or less of the applicable devices.			
PRC-009-0	R1.	The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:	The responsible entity that owns or operates a UFLS program failed to include one of the elements listed in PRC-009-0 R1.1 through R1.4 in the analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.	The responsible entity that owns or operates a UFLS program failed to include two of the elements listed in PRC-009-0 R1.1 through R1.4 in the analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.	The responsible entity that owns or operates a UFLS program failed to include three of the elements listed in PRC-009-0 R1.1 through R1.4 in the analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.	The responsible entity that owns or operates a UFLS program failed to conduct an analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.
PRC-009-0	R1.1.	A description of the event including initiating conditions.	N/A	N/A	N/A	N/A
PRC-009-0	R1.2.	A review of the UFLS set points and tripping times.	N/A	N/A	N/A	N/A
PRC-009-0	R1.3.	A simulation of the event.	N/A	N/A	N/A	N/A
PRC-009-0	R1.4.	A summary of the findings.	N/A	N/A	N/A	N/A

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PRC-009-0	R2.	The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.	The responsible entity has provided the documentation in more than 90 calendar days but less than 105 calendar days.	The responsible entity has provided the documentation in more than 105 calendar days but less than 129 calendar days.	The responsible entity has provided the documentation in more than 129 calendar days but less than 145 calendar days.	The responsible entity has provided the documentation in 145 calendar days or more.
PRC-010-0	R1.	The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall periodically (at least every five years or as required by changes in system conditions) conduct and document an assessment of the effectiveness of the UVLS program. This assessment shall be conducted with the associated Transmission Planner(s) and Planning Authority(ies).	The responsible entity conducted an assessment of the effectiveness of its UVLS system within 5 years or as required by changes in system conditions but did not include the associated Transmission Planner(s) and Planning Authority(ies).	The responsible entity did not conduct an assessment of the effectiveness of its UVLS system for more than 5 years but did in less than or equal to 6 years. OR The assessment of the effectiveness of the responsible entity's UVLS system did not address one of the elements in R1 (R1.1.1 through R1.1.3).	The responsible entity did not conduct an assessment of the effectiveness of its UVLS system for more than 6 years but did in less than or equal to 7years. OR The assessment of the effectiveness of the responsible entity's UVLS system did not address two of the elements in R1 (R1.1.1 through R1.1.3).	The responsible entity did not conduct an assessment of the effectiveness of its UVLS system for more than 7 years. OR The assessment of the effectiveness of the responsible entity's UVLS system did not address any of the elements in R1 (R1.1.1 through R1.1.3).
PRC-010-0	R1.1.	This assessment shall include, but is not limited to:	N/A	N/A	N/A	N/A
PRC-010-0	R1.1.1.	Coordination of the UVLS programs with other protection and control systems in the Region and with other Regional Reliability Organizations, as appropriate.	N/A	N/A	N/A	N/A

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PRC-010-0	R1.1.2.	Simulations that demonstrate that the UVLS programs performance is consistent with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0.	N/A	N/A	N/A	N/A
PRC-010-0	R1.1.3.	A review of the voltage set points and timing.	N/A	N/A	N/A	N/A
PRC-010-0	R2. (Retired)	The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days).	The responsible entity provided documentation of its current UVLS program assessment more than 30 calendar but less than or equal to 40 calendar days following a request from its Regional Reliability Organization or NERC.	The responsible entity provided documentation of its current UVLS program assessment more than 40 calendar days but less than or equal to 50 calendar days following a request from its Regional Reliability Organization or NERC.	The responsible entity provided documentation of its current UVLS program assessment more than 50 calendar days but less than or equal to 60 calendar days following a request from its Regional Reliability Organization or NERC.	The responsible entity did not provide documentation of its current UVLS program assessment for more than 60 calendar days following a request from its Regional Reliability Organization or NERC.
PRC-011-0	R1.	The Transmission Owner and Distribution Provider that owns a UVLS system shall have a UVLS equipment maintenance and testing program in place. This program shall include:	The responsible entity's UVLS equipment maintenance and testing program did not address one of the subrequirements in R1.2 through R1.6. OR The responsible entity's UVLS program did not address one of the equipment classes as specified in R1.1.1 through R1.1.4.	The responsible entity's UVLS equipment maintenance and testing program did not address two of the subrequirements in R1.2 through R1.6. OR The responsible entity's UVLS program did not address two of the equipment classes as specified in R1.1.1	The responsible entity's UVLS equipment maintenance and testing program did not address three of the subrequirements in R1.1 through R1.6. OR The responsible entity's UVLS program did not address three of the equipment classes as specified in R1.1.1 through R1.1.4.	The responsible entity's UVLS equipment maintenance and testing program did not address four or more of the subrequirements in R1.2 through R1.6. OR The responsible entity's UVLS program did not address any of the equipment classes as specified in R1.1.1

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				through R1.1.4.		through R1.1.4.
PRC-011-0	R1.1.	The UVLS system identification which shall include but is not limited to:	N/A	N/A	N/A	N/A
PRC-011-0	R1.1.1.	Relays.	N/A	N/A	N/A	N/A
PRC-011-0	R1.1.2.	Instrument transformers.	N/A	N/A	N/A	N/A
PRC-011-0	R1.1.3.	Communications systems, where appropriate.	N/A	N/A	N/A	N/A
PRC-011-0	R1.1.4.	Batteries.	N/A	N/A	N/A	N/A
PRC-011-0	R1.2.	Documentation of maintenance and testing intervals and their basis.	N/A	N/A	N/A	N/A
PRC-011-0	R1.3.	Summary of testing procedure.	N/A	N/A	N/A	N/A
PRC-011-0	R1.4.	Schedule for system testing.	N/A	N/A	N/A	N/A
PRC-011-0	R1.5.	Schedule for system maintenance.	N/A	N/A	N/A	N/A
PRC-011-0	R1.6.	Date last tested/maintained.	N/A	N/A	N/A	N/A
PRC-011-0	R2.	The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days).	The responsible entity provided documentation of its UVLS equipment maintenance and testing program more than 30 but less than or equal to 40 days following a request from its Regional Reliability Organization and/or NERC. OR Evidence UVLS equipment was maintained and tested within the defined intervals was missing	The responsible entity provided documentation of its UVLS equipment maintenance and testing program more than 40 but less than or equal to 50 days following a request from its Regional Reliability Organization and/or NERC. OR Evidence UVLS equipment was maintained and tested within the defined intervals was	The responsible entity provided documentation of its UVLS equipment maintenance and testing program more than 50 but less than or equal to 60 days following a request from its Regional Reliability Organization and/or NERC. OR Evidence UVLS equipment was maintained and tested within the defined intervals was missing for more than 10% up to (and including) 15% of the applicable devices.	The responsible entity did not provide documentation of its UVLS equipment maintenance and testing program for more than 60 days following a request from its Regional Reliability Organization and/or NERC. OR Evidence UVLS equipment was maintained and tested within the defined intervals was missing for more than 15% of

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			for 5% or less of the applicable devices.	missing for more than 5% up to (and including) 10% of the applicable devices.		the applicable devices.
PRC-015-0	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R 1.	N/A	The responsible entity's list of existing or proposed SPSs did not address one of the subrequirements in R1.1 through R1.3 as specified in Reliability Standard PRC-013-0_R1.	The responsible entity's list of existing or proposed SPSs did not address two of the subrequirements in R1.1 through R1.3 as specified in Reliability Standard PRC-013-0_R1.	The responsible entity's list of existing or proposed SPSs did not address any of the subrequirements in R1.1 through R1.3 as specified in Reliability Standard PRC-013-0_R1.
PRC-015-0	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.	The responsible entity was not compliant in that evidence that it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures did not address one of the subrequirements in R1.1 through R1.9 as specified in Reliability Standard PRC-012-0_R1 prior to being placed in service.	The responsible entity was not compliant in that evidence that it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures did not address two of the subrequirements in R1.1 through R1.9 as specified in Reliability Standard PRC-012-0_R1 prior to being placed in service.	The responsible entity was not compliant in that evidence that it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures did not address three of the subrequirements in R1.1 through R1.9 as specified in Reliability Standard PRC-012-0_R1 prior to being placed in service.	The responsible entity was not compliant in that evidence that it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures did not address four or more of the subrequirements in R1.1 through R1.9 as specified in Reliability Standard PRC-012-0_R1 prior to being placed in service.
PRC-015-0	R3.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and	The responsible entity provided documentation of its	The responsible entity provided documentation of its	The responsible entity provided documentation of its SPS data and the	The responsible entity provided documentation of its

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the results of studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).	SPS data and the results of the studies that show compliance of new or functionally modified SPSs more than 30 calendar days but less than or equal to 40 calendar days following a request from its Regional Reliability Organization or NERC.	SPS data and the results of the studies that show compliance of new or functionally modified SPSs more than 40 calendar days but less than or equal to 50 calendar days following a request from its Regional Reliability Organization or NERC.	results of the studies that show compliance of new or functionally modified SPSs more than 50 calendar days but less than or equal to 60 calendar days following a request from its Regional Reliability Organization or NERC.	SPS data and the results of the studies that show compliance of new or functionally modified SPSs more than 60 calendar days following a request from its Regional Reliability Organization or NERC.
PRC-016-0.1	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R 1.	N/A	N/A	N/A	The responsible entity that owns an SPS did not analyze its SPS operations and maintain a record of all Misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R 1.
PRC-016-0.1	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.	For each Misoperation, the responsible entity that owns an SPS did not take 5% or less of the corrective actions designed to avoid future SPS Misoperations.	For each Misoperation, the responsible entity that owns an SPS did not take more than 5% up to (and including) 10% of the corrective actions designed to avoid future SPS Misoperations.	For each Misoperation, the responsible entity that owns an SPS did not take more than 10% up to (and including) 15% of the corrective actions designed to avoid future SPS Misoperations.	For each Misoperation, the responsible entity that owns an SPS did not take more than 15% of the corrective actions designed to avoid future SPS Misoperations.
PRC-016-	R3.	The Transmission Owner, Generator Owner,	The responsible entity	The responsible	The responsible entity	The responsible entity

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0.1		and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	provided documentation of its SPS Misoperation analyses and the corrective action plans more than 90 calendar days but less than or equal to 120 calendar days following a request from its Regional Reliability Organization or NERC.	entity provided documentation of its SPS Misoperation analyses and the corrective action plans more than 120 calendar days but less than or equal to 130 calendar days following a request from its Regional Reliability Organization or NERC.	provided documentation of its SPS Misoperation analyses and the corrective action plans more than 130 calendar days but less than or equal to140 calendar days following a request from its Regional Reliability Organization or NERC.	provided documentation of its SPS Misoperation analyses and the corrective action plans more than 140 calendar days following a request from its Regional Reliability Organization or NERC. OR Did not provide the documentation.
PRC-017-0	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:	The responsible entity's SPS equipment maintenance and testing program did not address one of the subrequirements in R1.2 through R1.6. OR The responsible entity's SPS program did not address one of the equipment classes as specified in R1.1.1 through R1.1.4.	The responsible entity's SPS equipment maintenance and testing program did not address two of the subrequirements in R1.2 through R1.6. OR The responsible entity's SPS program did not address two of the equipment classes as specified in R1.1.1 through R1.1.4.	The responsible entity's SPS equipment maintenance and testing program did not address three of the subrequirements in R1.2 through R1.6. OR The responsible entity's SPS program did not address three of the equipment classes as specified in R1.1.1 through R1.1.4.	The responsible entity's SPS equipment maintenance and testing program did not address four or more of the subrequirements in R1.2 through R1.6. OR The responsible entity's SPS program did not address any of the equipment classes as specified in R1.1.1 through R1.1.4.
PRC-017-0	R1.1.	SPS identification shall include but is not limited to:	N/A	N/A	N/A	N/A
PRC-017-0	R1.1.1.	Relays.	N/A	N/A	N/A	N/A
PRC-017-0	R1.1.2.	Instrument transformers.	N/A	N/A	N/A	N/A

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PRC-017-0	R1.1.3.	Communications systems, where appropriate.	N/A	N/A	N/A	N/A
PRC-017-0	R1.1.4.	Batteries.	N/A	N/A	N/A	N/A
PRC-017-0	R1.2.	Documentation of maintenance and testing intervals and their basis.	N/A	N/A	N/A	N/A
PRC-017-0	R1.3.	Summary of testing procedure.	N/A	N/A	N/A	N/A
PRC-017-0	R1.4.	Schedule for system testing.	N/A	N/A	N/A	N/A
PRC-017-0	R1.5.	Schedule for system maintenance.	N/A	N/A	N/A	N/A
PRC-017-0	R1.6.	Date last tested/maintained.	N/A	N/A	N/A	N/A
PRC-017-0	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).	The responsible entity provided documentation of its SPS maintenance and testing program more than 30 but less than or equal to 40 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity provided documentation of its SPS maintenance and testing program more than 40 but less than or equal to 50 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity provided documentation of its SPS maintenance and testing program more than 50 but less than or equal to 60 days following a request from its Regional Reliability Organization and/or NERC.	The responsible entity did not provide documentation of its SPS maintenance and testing program for more than 60 days following a request from its Regional Reliability Organization and/or NERC.
PRC-018-1	R1.	Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements:	N/A	N/A	The installation of DMEs does not include one of the subrequirements in R1.1 and R1.2.	The installation of DMEs does not include any of the subrequirements in R1.1 and R1.2.
PRC-018-1	R1.1.	Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)	N/A	N/A	N/A	N/A
PRC-018-1	R1.2.	Recorded data from each Disturbance shall be retrievable for ten calendar days.	N/A	N/A	N/A	N/A
PRC-018-1	R2.	The Transmission Owner and Generator Owner shall each install DMEs in	The responsible entity failed to install 5% or	The responsible entity failed to	The responsible entity failed to install more	The responsible entity failed to install more

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		accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3).	less of the DME devices in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 R1 through R3.	install more than 5% up to (and including) 10% of the DME devices in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 R1 through R3.	than 10% up to (and including) 15% of the DME devices in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 R1 through R3.	than 15% of the DME devices in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 R1 through R3.
PRC-018-1	R3.	The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1):	Evidence that the responsible entity maintained data on the DMEs installed to meet that region's installation requirements was missing or not reported for one of the subrequirements in R3.1 through R3.8.	Evidence that the responsible entity maintained data on the DMEs installed to meet that region's installation requirements was missing or not reported for two of the subrequirements in R3.1 through R3.8.	Evidence that the responsible entity maintained data on the DMEs installed to meet that region's installation requirements was missing or not reported for three of the subrequirements in R3.1 through R3.8.	Evidence that the responsible entity maintained data on the DMEs installed to meet that region's installation requirements was missing or not reported for four or more of the subrequirements in R3.1 through R3.8.
PRC-018-1	R3.1.	Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).	N/A	N/A	N/A	N/A
PRC-018-1	R3.2.	Make and model of equipment.	N/A	N/A	N/A	N/A
PRC-018-1	R3.3.	Installation location.	N/A	N/A	N/A	N/A
PRC-018-1	R3.4.	Operational status.	N/A	N/A	N/A	N/A
PRC-018-1	R3.5.	Date last tested.	N/A	N/A	N/A	N/A
PRC-018-1	R3.6.	Monitored elements, such as transmission circuit, bus section, etc.	N/A	N/A	N/A	N/A
PRC-018-1	R3.7.	Monitored devices, such as circuit breaker, disconnect status, alarms, etc.	N/A	N/A	N/A	N/A

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-018-1	R3.8.	Monitored electrical quantities, such as voltage, current, etc.	N/A	N/A	N/A	N/A
PRC-018-1	R4.	The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4).	The responsible entity did not provide 5% or less of the disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements.	The responsible entity did not provide more than 5% up to (and including) 10% of the disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements.	The responsible entity did not provide more than 10% up to (and including) 15% of the disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements.	The responsible entity did not provide more than 15% of the disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements.
PRC-018-1	R5.	The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.	5% or less of the responsible entity's data recorded by DMEs for Regional Reliability Organization-identified events was not archived for at least three years.	More than 5% up to (and including) 10% of the responsible entity's data recorded by DMEs for Regional Reliability Organization-identified events was not archived for at least three years.	More than 10% up to (and including) 15% of the responsible entity's data recorded by DMEs for Regional Reliability Organization-identified events was not archived for at least three years.	More than 15% of the responsible entity's data recorded by DMEs for Regional Reliability Organization-identified events was not archived for at least three years.
PRC-018-1	R6.	Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:	N/A	N/A	The responsible entity is not compliant in that the maintenance and testing program for DMEs does not include one of the elements in R6.1 and 6.2.	The responsible entity is not compliant in that the maintenance and testing program for DMEs does not include any of the elements in R6.1 and 6.2.
PRC-018-1	R6.1.	Maintenance and testing intervals and their basis.	The responsible entity's DME maintenance and testing program was	The responsible entity's DME maintenance and testing program was	The responsible entity's DME maintenance and testing program was non-compliant in that	The responsible entity's DME maintenance and testing program was

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			non-compliant in that documentation of maintenance and testing intervals and their basis was missing for no more than 25% of the DME equipment.	non-compliant in that documentation of maintenance and testing intervals and their basis was missing for more than 25% but less than or equal to 50% of the DME equipment.	documentation of maintenance and testing intervals and their basis was missing for more than 50% but less than or equal to 75% of the DME equipment.	non-compliant in that documentation of maintenance and testing intervals and their basis was missing for more than 75% of the DME equipment.
PRC-018-1	R6.2.	Summary of maintenance and testing procedures.	The responsible entity's DME maintenance and testing program was non-compliant in that the summary of maintenance and testing procedures documentation was missing for no more than 25% of the DME equipment.	The responsible entity's DME maintenance and testing program was non-compliant in that the summary of maintenance and testing procedures documentation was missing for more than 25% but less than or equal to 50% of the DME equipment.	The responsible entity's DME maintenance and testing program was non-compliant in that the summary of maintenance and testing procedures documentation was missing for more than 50% but less than or equal to 75% of the DME equipment.	The responsible entity's DME maintenance and testing program was non-compliant in that the summary of maintenance and testing procedures documentation was missing for more than 75% of the DME equipment.
PRC-021-1	R1.	Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:	UVLS data was provided but did not address one of the subrequirements in R1.1 through R1.5.	UVLS data was provided but did not address two of the subrequirements in R1.1 through R1.5.	UVLS data was provided but did not address three of the subrequirements in R1.1 through R1.5.	No annual UVLS data was provided. OR UVLS data was provided but did not address four or more of the subrequirements in R1.1 through R1.5.
PRC-021-1	R1.1.	Size and location of customer load, or percent of connected load, to be interrupted.	N/A	N/A	N/A	N/A
PRC-021-1	R1.2.	Corresponding voltage set points and overall	N/A	N/A	N/A	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		scheme clearing times.				
PRC-021-1	R1.3.	Time delay from initiation to trip signal.	N/A	N/A	N/A	N/A
PRC-021-1	R1.4.	Breaker operating times.	N/A	N/A	N/A	N/A
PRC-021-1	R1.5.	Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems.	N/A	N/A	N/A	N/A
PRC-021-1	R2.	Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.	The responsible entity updated its UVLS data more than 30 calendar days but less than or equal to 40 calendar days following a request from its Regional Reliability Organization.	The responsible entity updated its UVLS data more than 40 calendar days but less than or equal to 50 calendar days following a request from its Regional Reliability Organization.	The responsible entity updated its UVLS data more than 50 calendar days but less than or equal to 60 calendar days following a request from its Regional Reliability Organization.	The responsible entity did not update its UVLS data for more than 60 calendar days following a request from its Regional Reliability Organization.
PRC-022-1	R1.	Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall analyze and document all UVLS operations and Misoperations. The analysis shall include:	The overall analysis program did not address one of the subrequirements in R1.1 through R1.5.	The overall analysis program did not address two of the subrequirements in R1.1 through R1.5.	The overall analysis program did not address three of the subrequirements in R1.1 through R1.5.	The responsible entity failed to analyze and document a UVLS operation and Misoperation. OR The overall analysis program did not address four or more of the subrequirements in R1.1 through R1.5.
PRC-022-1	R1.1.	A description of the event including initiating conditions.	N/A	N/A	N/A	N/A
PRC-022-1	R1.2.	A review of the UVLS set points and tripping times.	N/A	N/A	N/A	N/A

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-022-1	R1.3.	A simulation of the event, if deemed appropriate by the Regional Reliability Organization. For most events, analysis of sequence of events may be sufficient and dynamic simulations may not be needed.	N/A	N/A	N/A	N/A
PRC-022-1	R1.4.	A summary of the findings.	N/A	N/A	N/A	N/A
PRC-022-1	R1.5.	For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature.	N/A	N/A	N/A	N/A
PRC-022-1	R2. (Retired)	Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90 calendar days of a request.	The responsible entity provided documentation of the analysis of UVLS program performance more than 90 calendar days but less than or equal to 120 calendar days following a request from its Regional Reliability Organization.	The responsible entity provided documentation of the analysis of UVLS program performance more than 120 calendar days but less than or equal to 130 calendar days following a request from its Regional Reliability Organization.	The responsible entity provided documentation of the analysis of UVLS program performance more than 130 calendar days but less than or equal to 140 calendar days following a request from its Regional Reliability Organization.	The responsible entity did not provide documentation of the analysis of UVLS program performance for more than 140 calendar days following a request from its Regional Reliability Organization.
PRC-023-1	R1.	Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Mitigation Time Horizon: Long		Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or incorrect for one or more of the subrequirements.		Relay settings do not comply with any of the sub requirements R1.1 through R1.13 OR Evidence does not exist to support that relay settings comply with one of the criteria in subrequirements R1.1 through R1.13.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Term Planning].				
PRC-023-1	R2.	The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. [Time Horizon: Long Term Planning]	Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.			
PRC-023-1	R3.	The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Time Horizon: Long Term Planning]		Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated.	Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated.	Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System. OR Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System, OR Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more than 60

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						days after the list was established or updated.
PRC-023-2	R1	Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [See Standard for Criteria]	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
PRC-023-2	R2	Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-023-2	R3	Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 6, 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit. OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
PRC-023-2	R4	Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports.	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
PRC-023-2	R5	Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability.	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
PRC-023-2	R6	Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[See standard for what the Planning Coordinator shall do]*	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments. OR The Planning	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard. OR The Planning Coordinator used the criteria established

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the	Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)		OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						which applicable entities must comply with the standard.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
TOP-001-1a	R1.	Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	N/A	N/A	N/A	The Transmission Operator has no evidence that clear decision-making authority exists to assure reliability in its area or has failed to exercise this authority to alleviate operating emergencies.
TOP-001-1a	R2.	Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	N/A	N/A	N/A	The Transmission Operator failed to have evidence that it took immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.
TOP-001-1a	R3.	Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority, or Generator Operator shall immediately inform the	N/A	N/A	N/A	The responsible entity failed to comply with reliability directives issued by the Reliability Coordinator or the Transmission Operator (when applicable), when said directives would not have resulted in actions that would violate safety,

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.				equipment, regulatory or statutory requirements, or under circumstances that said directives would have resulted in actions that would violate safety, equipment, regulatory or statutory requirements the responsible entity failed to inform the Reliability Coordinator or Transmission Operator (when applicable) of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator could implement alternate remedial actions.
TOP-001-1a	R4.	Each Distribution Provider and Load-Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load-Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	N/A	N/A	N/A	The responsible entity failed to comply with all reliability directives issued by the Transmission Operator, including shedding firm load, when said directives would not have resulted in actions that would violate safety, equipment, regulatory or statutory requirements, or under

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						circumstances when said directives would have violated safety, equipment, regulatory or statutory requirements, the responsible entity failed to immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator could implement alternate remedial actions.
TOP-001-1a	R5.	Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real-time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	N/A	The Transmission Operator failed to inform its Reliability Coordinator and any other potentially affected Transmission Operators of real-time or anticipated emergency conditions, but did take actions to avoid, when possible, or mitigate the emergency.	N/A	The Transmission Operator failed to inform its Reliability Coordinator and any other potentially affected Transmission Operators of real-time or anticipated emergency conditions, and failed to take actions to avoid, when possible, or mitigate the emergency.
TOP-001-1a	R6.	Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	N/A	N/A	N/A	The responsible entity failed to render all available emergency assistance to others as requested, after the requesting entity had implemented its comparable

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						emergency procedures, when said assistance would not have resulted in actions that would violate safety, equipment, or regulatory or statutory requirements.
TOP-001-1a	R7.	Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:	N/A	N/A	N/A	The responsible entity removed Bulk Electric System facilities from service and removal of said facilities burdened a neighboring system, without complying with the applicable requirements listed in R7.1 through R7.3.
TOP-001-1a	R7.1.	For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.	N/A	N/A	N/A	N/A
TOP-001-1a	R7.2.	For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.	N/A	N/A	N/A	N/A
TOP-001-1a	R7.3.	When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public,	N/A	N/A	N/A	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.				
TOP-001-1a	R8.	During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	N/A	N/A	N/A	The responsible entity failed to take immediate actions to restore the Real and Reactive Power Balance during a system emergency. OR The responsible entity failed to request emergency assistance from the Reliability Coordinator during a period when it was unable to restore the Real and Reactive Power Balance, OR During a period when corrective actions or emergency assistance was not adequate to mitigate the Real and Reactive Power Balance, the responsible entity failed to implement firm load shedding.
TOP-002-2.1b	R1.	Each Balancing Authority and Transmission Operator shall maintain a set of current plans	N/A	N/A	The responsible entity maintained a set of	The responsible entity failed to maintain a set

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.			current plans that were designed to evaluate options and set procedures for reliable operation through a reasonable future time period, but failed to utilize available personnel and system equipment to implement these plans to ensure that interconnected system reliability would be maintained.	of current plans that were designed to evaluate options and set procedures for reliable operation through a reasonable future time period.
TOP-002-2.1b	R2.	Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	N/A	N/A	N/A	The responsible entity failed to ensure its operating personnel participated in the system planning and design study processes.
TOP-002-2.1b	R3.	Each Load-Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	N/A	The Load-Serving Entity or Generator Operator failed to coordinate (where confidentiality agreements allow) its seasonal operations with its Host Balancing Authority and Transmission Service Provider, or the Balancing Authority or Transmission Service Provider failed to coordinate its seasonal	N/A	The Load-Serving Entity or Generator Operator failed to coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider, or the Balancing Authority or Transmission Service Provider failed

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				operations with its Transmission Operator.		to coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.
TOP-002-2.1b	R4.	Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.	N/A	The responsible entity failed to coordinate (where confidentiality agreements allow) one of the following three categories of operations (current-day, next-day or seasonal) with the applicable entity(ies)	The responsible entity failed to coordinate (where confidentiality agreements allow) two of the following three categories of operations (current-day, next-day or seasonal) with the applicable entity(ies)	The responsible entity failed to coordinate (where confidentiality agreements allow) all three of the following categories of operations (current-day, next-day or seasonal) with the applicable entity(ies)
TOP-002-2.1b	R5.	Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	N/A	N/A	N/A	The responsible entity failed to plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.
TOP-002-2.1b	R6.	Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	N/A	N/A	N/A	The responsible entity failed to plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional and local reliability

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						requirements.
TOP-002-2.1b	R7.	Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	N/A	N/A	N/A	The Balancing Authority failed to plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.
TOP-002-2.1b	R8.	Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	N/A	N/A	N/A	The Balancing Authority failed to plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.
TOP-002-2.1b	R9.	Each Balancing Authority shall plan to meet Interchange Schedules and Ramps.	N/A	N/A	N/A	The Balancing Authority failed to plan to meet Interchange Schedules and Ramps.
TOP-002-2.1b	R10.	Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	N/A	N/A	N/A	The responsible entity failed to plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).
TOP-002-2.1b	R11.	The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update	N/A	N/A	The Transmission Operator performed seasonal, next-day, and current-day Bulk Electric System studies, reflecting	The Transmission Operator failed to perform seasonal, next-day, or current-day Bulk Electric System studies,

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.			current system conditions, to determine SOLs, but failed to make the results of Bulk Electric System studies available to all of the Transmission Operators, Balancing Authorities (subject confidentiality requirements), or to its Reliability Coordinator.	reflecting current system conditions, to determine SOLs.
TOP-002-2.1b	R12.	The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.	N/A	N/A	N/A	The Transmission Service Provider failed to include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.
TOP-002-2.1b	R13.	At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	N/A	N/A	N/A	The Generator Operator failed to perform generating real and reactive capability verification that included, among other variables, weather, ambient air and water conditions,

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						and fuel quality and quantity, or failed to provide the results of generating real and reactive verifications Balancing Authority or Transmission Operator operating personnel, when requested.
TOP-002-2.1b	R14.	Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:	N/A	N/A	N/A	The Generator Operator failed to notify its Balancing Authority or Transmission Operator of changes in capabilities and characteristics including real output capabilities.
TOP-002-2.1b	R14.1.	Changes in real output capabilities.	N/A	N/A	N/A	N/A
TOP-002-2.1b	R15.	Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	N/A	N/A	N/A	The Generator Operator failed to provide, at the request of the Balancing Authority or Transmission Operator, a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).
TOP-002-2.1b	R16.	Subject to standards of conduct and confidentiality agreements, Transmission	N/A	N/A	N/A	The Transmission Operator failed to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:				notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics, within the terms and conditions of standards of conduct and confidentiality agreements.
TOP-002-2.1b	R16.1.	Changes in transmission facility status.	N/A	N/A	N/A	The Transmission Operator failed to notify their Reliability Coordinator and Balancing Authority of changes in transmission facility status, within the terms and conditions of standards of conduct and confidentiality agreements.
TOP-002-2.1b	R16.2.	Changes in transmission facility rating.	N/A	N/A	N/A	The Transmission Operator failed to notify their Reliability Coordinator and Balancing Authority of changes in transmission facility rating, within the terms and conditions of standards of conduct and confidentiality agreements.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
TOP-002-2.1b	R17.	Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	N/A	N/A	N/A	The responsible entity failed to communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.
TOP-002-2.1b	R18.	Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers, and Load-Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.	N/A	N/A	N/A	The responsible entity failed to use uniform line identifiers when referring to transmission facilities of an interconnected network.
TOP-002-2.1b	R19.	Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	N/A	N/A	N/A	The responsible entity failed to maintain accurate computer models utilized for analyzing and planning system operations.
TOP-004-2	R1.	Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	N/A	N/A	N/A	The Transmission Operator failed to operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).
TOP-004-2	R2.	Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	N/A	N/A	N/A	The Transmission Operator failed to operate so that instability, uncontrolled separation, or cascading outages

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						would not occur as a result of the most severe single contingency.
TOP-004-2	R3.	Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	N/A	N/A	N/A	The Transmission Operator failed to operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by Reliability Coordinator policy.
TOP-004-2	R4.	If a Transmission Operator enters an unknown operating state (i.e., any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	N/A	N/A	N/A	The Transmission Operator entered an unknown operating state (i.e., any state for which valid operating limits have not been determined), and failed to restore operations to respect proven reliable power system limits for more than 30 minutes.
TOP-004-2	R5.	Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.	N/A	N/A	N/A	The Transmission Operator did not make every effort to remain connected to the Interconnection except when the Transmission Operator determined that by remaining

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						interconnected, it was in imminent danger of violating an IROL or SOL.
TOP-004-2	R6.	Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:	The Transmission Operator, individually and jointly with other Transmission Operators, developed, maintained, and implemented formal policies and procedures to provide for transmission reliability, addressing the execution and coordination of activities that impact inter- and intra-Regional reliability, but failed to include information required by one of the subrequirements R6.1 thru R6.4	The Transmission Operator, individually and jointly with other Transmission Operators, developed, maintained, and implemented formal policies and procedures to provide for transmission reliability, addressing the execution and coordination of activities that impact inter- and intra-Regional reliability, but failed to include information required by 2 of the subrequirements R6.1 thru R6.4.	The Transmission Operator, individually and jointly with other Transmission Operators, developed, maintained, and implemented formal policies and procedures to provide for transmission reliability, addressing the execution and coordination of activities that impact inter- and intra-Regional reliability, but failed to include information required by 3 of the subrequirements R6.1 thru R6.4.	The Transmission Operator, failed to develop, maintain, and implemented formal policies and procedures to provide for transmission reliability, addressing the execution and coordination of activities that impact inter- and intra-Regional reliability. If formal policies and procedures were developed, such policies and procedures failed to include any of the information required in subrequirements R6.1 thru R6.4.
TOP-004-2	R6.1.	Monitoring and controlling voltage levels and real and reactive power flows.	N/A	N/A	N/A	N/A
TOP-004-2	R6.2.	Switching transmission elements.	N/A	N/A	N/A	N/A
TOP-004-2	R6.3.	Planned outages of transmission elements.	N/A	N/A	N/A	N/A
TOP-004-2	R6.4.	Responding to IROL and SOL violations.	N/A	N/A	N/A	N/A
TOP-007-0	R1.	A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within	N/A	N/A	The Transmission Operator informed its Reliability Coordinator when an IROL or SOL had been exceeded but	The Transmission Operator failed to inform its Reliability Coordinator when an IROL or SOL had

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		limits.			failed to provide the actions being taken to return the system to within limits.	been exceeded.
TOP-007-0	R2.	Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	Following a Contingency or other event that resulted in an IROL violation of a magnitude of 5% or less, the Transmission Operator failed to return its transmission system to within the IROL in less than or equal to 35 minutes.	Following a Contingency or other event that resulted in an IROL violation, the Transmission Operator failed to return its transmission system to within the IROL in accordance with the following: (a) an IROL with a magnitude of 5% or less for a period of time greater than 35 minutes but less than or equal to 45 minutes, or (b) an IROL with a magnitude of more than 5% up to (and including) 10% for a period of time less than or equal to 40 minutes, or (c) an IROL with a magnitude of more than 10% up to (and including) 15% for a period of time less than or equal to 35 minutes.	Following a Contingency or other event that resulted in an IROL violation, the Transmission Operator failed to return its transmission system to within the IROL in accordance with the following: (a) an IROL with a magnitude of 5% or less for a period of time greater than 45 minutes, or (b) an IROL with a magnitude of more than 5% up to (and including) 10% for a period of time greater than 40 minutes, or (c) an IROL with a magnitude of more than 10% up to (and including) 15% for a period of time greater than 35 minutes but less than or equal to 45 minutes, or (d) an IROL with a magnitude of more than 15% up to (and including) 20% for a	Following a Contingency or other event that resulted in an IROL violation, the Transmission Operator failed to return its transmission system to within the IROL in accordance with the following: (a) an IROL with a magnitude of more than 10% up to (and including) 15% for a period of time greater than 45 minutes, or (b) an IROL with a magnitude of more than 15% up to (and including) 20% for a period of time greater than 40 minutes, or (c) an IROL with a magnitude of more than 20% up to (and including) 25% for a period of time greater than 35 minutes, or (d) an IROL with a magnitude of more than 25% for a period of greater than 30 minutes.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					period of time less than or equal to 40 minutes, or (e) an IROL with a magnitude of more than 20% up to (and including) 25% for a period of time less than or equal to 35 minutes.	
TOP-007-0	R3.	A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R 2.	N/A	N/A	N/A	The Transmission Operator failed to take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to return the transmission system to IROL within 30 minutes.
TOP-007-0	R4.	The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	N/A	N/A	N/A	The Reliability Coordinator failed to evaluate actions taken to address an IROL or SOL violation and, if the actions taken were not appropriate or sufficient, direct actions required to return the system to within limits.
TOP-008-1	R1.	The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	N/A	N/A	N/A	The Transmission Operator experiencing or contributing to an IROL or SOL violation failed to take immediate steps to

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						relieve the condition, which may have included shedding firm load.
TOP-008-1	R2.	Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.	N/A	N/A	The Transmission Operator operated to prevent the likelihood that a disturbance, action, or inaction would result in an IROL or SOL violation in its area or another area of the Interconnection but failed to operate the Bulk Electric System to the most limiting parameter in instances where there was a difference in derived operating limits.	The Transmission Operator failed to operate to prevent the likelihood that a disturbance, action, or inaction would result in an IROL or SOL violation in its area or another area of the Interconnection.
TOP-008-1	R3.	The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	N/A	N/A	The Transmission Operator disconnected the affected facility when the overload on a transmission facility or abnormal voltage or reactive condition persisted and equipment was endangered but failed to notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection either prior to	The Transmission Operator failed to disconnect the affected facility when the overload on a transmission facility or abnormal voltage or reactive condition persisted and equipment was endangered.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					switching, if time permitted, otherwise, immediately thereafter.	
TOP-008-1	R4.	The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	N/A	N/A	The Transmission Operator had sufficient information and analysis tools to determine the cause(s) of SOL violations and used the results of these analyses to immediately mitigate the SOL violation(s), but failed to conduct these analyses in all operating timeframes.	The Transmission Operator failed to have sufficient information and analysis tools to determine the cause(s) of SOL violations or failed to use the results of analyses to immediately mitigate the SOL violation.

Complete Violation Severity Level Matrix (TPL)
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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
TPL-001-0.1	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:	The responsible entity is non-compliant with 25% or less of the sub-components.	The responsible entity is non-compliant with more than 25% but less than 50% of the sub-components.	The responsible entity is non-compliant with 50% or more but less than 75% of the sub-components.	The responsible entity is non-compliant with 75% or more of the sub-components.
TPL-001-0.1	R1.1.	Be made annually.	N/A	N/A	N/A	The assessments were not made on an annual basis.
TPL-001-0.1	R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	The responsible entity has failed to demonstrate a valid assessment for the long-term period, but a valid assessment for the near-term period exists.	The responsible entity has failed to demonstrate a valid assessment for the near-term period, but a valid assessment for the long-term period exists.	N/A	The responsible entity has failed to demonstrate a valid assessment for the near-term period AND long-term planning period.
TPL-001-0.1	R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability	The responsible entity is non-compliant with 25% or less of the sub-components.	The responsible entity is non-compliant with more than 25% but less than 50% of the sub-components.	The responsible entity is non-compliant with 50% or more but less than 75% of the sub-components.	The responsible entity is non-compliant with 75% or more of the sub-components.

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Organization(s).				
TPL-001-0.1	R1.3.1.	Cover critical system conditions and study years as deemed appropriate by the entity performing the study.	N/A	N/A	N/A	The responsible entity has failed to cover critical system conditions and study years as deemed appropriate.
TPL-001-0.1	R1.3.2.	Be conducted annually unless changes to system conditions do not warrant such analyses.	The responsible entity's most recent long-term studies (and/or system simulation testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system testing) are no longer valid.	The responsible entity's most recent near-term studies (and/or system simulation testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system testing) are no longer valid.	N/A	The responsible entity's most recent near-term studies (and/or system testing) AND most recent long-term studies (and/or system simulation testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system testing) are no longer valid.
TPL-001-0.1	R1.3.3.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	N/A	N/A	N/A	The responsible entity failed to produce evidence of a past or current year long-term study and/or system simulation testing (beyond 5-year planning horizon) when past or current year near-term studies and/or system simulation testing

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						show marginal conditions that may require longer lead-time solutions.
TPL-001-0.1	R1.3.4.	Have established normal (pre-contingency) operating procedures in place.	N/A	N/A	N/A	No precontingency operating procedures are in place for existing facilities.
TPL-001-0.1	R1.3.5.	Have all projected firm transfers modeled.	The system model(s) used for current or past analysis did not properly represent up to (but less than) 25% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 25% or more but less than 50% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 50% or more but less than 75% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 75% or more of the firm transfers to/from the responsible entity's service territory.
TPL-001-0.1	R1.3.6.	Be performed for selected demand levels over the range of forecast system demands.	N/A	N/A	N/A	The responsible entity has failed to produce evidence of a valid current or past study and/or system simulation testing reflecting analysis over a range of forecast system demands.
TPL-001-0.1	R1.3.7.	Demonstrate that system performance meets Table 1 for Category A (no contingencies).	N/A	N/A	N/A	No past or current study results exist showing pre-contingency system analysis.
TPL-001-0.1	R1.3.8.	Include existing and planned facilities.	The responsible entity’s transmission model used for past or current studies and/or	The responsible entity’s transmission model used for past or current studies and/or	N/A	The responsible entity's transmission model used for past or current studies and/or

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			system simulation testing properly reflects existing facilities, but is deficient in reflecting planned facilities.	system simulation testing properly reflects planned facilities, but is deficient in reflecting existing facilities.		system simulation testing is deficient in reflecting existing AND planned facilities.
TPL-001-0.1	R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	N/A	N/A	N/A	The responsible entity has failed to ensure in a past or current study and/or system simulation testing that sufficient reactive power resources are available to meet required system performance.
TPL-001-0.1	R1.4.	Address any planned upgrades needed to meet the performance requirements of Category A.	N/A	N/A	N/A	The responsible entity has failed to demonstrate that a corrective action plan exists in order to satisfy Category A planning requirements.
TPL-001-0.1	R2.	When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each:	N/A	The responsible entity has failed to review the continuing need for previously identified facility additions through subsequent annual assessments. (R2.2)	The responsible entity provided documented evidence of corrective action plans in order to satisfy Category A planning requirements, but failed to include an implementation schedule with in-service dates (R2.1.1 and R2.1.2) OR The responsible entity	The responsible entity has failed to provide documented evidence of corrective action plans in order to satisfy Category A planning requirements. (R2.1)

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					failed to consider necessary lead times to implement its corrective action plan. (R2.1.3)	
TPL-001-0.1	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.	N/A	N/A	N/A	N/A
TPL-001-0.1	R2.1.1.	Including a schedule for implementation.	N/A	N/A	N/A	N/A
TPL-001-0.1	R2.1.2.	Including a discussion of expected required in-service dates of facilities.	N/A	N/A	N/A	N/A
TPL-001-0.1	R2.1.3.	Consider lead times necessary to implement plans.	N/A	N/A	N/A	N/A
TPL-001-0.1	R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	N/A	N/A	N/A	N/A
TPL-001-0.1	R3.	The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.	N/A	The responsible entity documented the results of its reliability assessments and corrective plans but did not annually provide them to its respective NERC Regional Reliability Organization(s) as required by the Regional Reliability Organization	N/A	The responsible entity DID NOT document the results of its annual reliability assessments and corrective plans AND did not annually provide them to its respective NERC Regional Reliability Organization(s) as required by the Regional Reliability Organization
TPL-002-0b	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a	The responsible entity is non-compliant with	The responsible entity is non-compliant with	The responsible entity is non-compliant with	The responsible entity is non-compliant with

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:	25% or less of the sub-components.	more than 25% but less than 50% of the sub-components.	50% or more but less than 75% of the sub-components.	75% or more of the sub-components.
TPL-002-0b	R1.1.	Be made annually.	N/A	N/A	N/A	The assessments were not made on an annual basis.
TPL-002-0b	R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	The responsible entity has failed to demonstrate a valid assessment for the long-term period, but a valid assessment for the near-term period exists.	The responsible entity has failed to demonstrate a valid assessment for the near-term period, but a valid assessment for the long-term period exists.	N/A	The responsible entity has failed to demonstrate a valid assessment for the near-term period AND long-term planning period.
TPL-002-0b	R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	The responsible entity is non-compliant with 25% or less of the sub-components.	The responsible entity is non-compliant with more than 25% but less than 50% of the sub-components.	The responsible entity is non-compliant with 50% or more but less than 75% of the sub-components.	The responsible entity is non-compliant with 75% or more of the sub-components.
TPL-002-0b	R1.3.1.	Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies	N/A	The responsible entity provided evidence through current or past studies and/or	N/A	The responsible entity did not provided evidence through current or past studies

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.		system simulation testing that selected NERC Category B contingencies were evaluated, however, no rational was provided to indicate why the remaining Category B contingencies for their system were not evaluated.		and/or system simulation testing to indicate that any NERC Category B contingencies were evaluated.
TPL-002-0b	R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	N/A	N/A	N/A	The responsible entity has failed to cover critical system conditions and study years as deemed appropriate.
TPL-002-0b	R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	The responsible entity's most recent long-term studies (and/or system simulation testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system testing) are no longer valid.	The responsible entity's most recent near-term studies (and/or system simulation testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system testing) are no longer valid.	N/A	The responsible entity's most recent near-term studies (and/or system simulation testing) AND most recent long-term studies (and/or system testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system simulation testing) are no longer valid.
TPL-002-0b	R1.3.4.	Be conducted beyond the five-year horizon	N/A	N/A	N/A	The responsible entity

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		only as needed to address identified marginal conditions that may have longer lead-time solutions.				failed to produce evidence of a past or current year long-term study and/or system simulation testing (beyond 5-year planning horizon) when past or current year near-term studies and/or system simulation testing show marginal conditions that may require longer lead-time solutions.
TPL-002-0b	R1.3.5.	Have all projected firm transfers modeled.	The system model(s) used for current or past analysis did not properly represent up to (but less than) 25% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 25% or more but less than 50% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 50% or more but less than 75% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 75% or more of the firm transfers to/from the responsible entity's service territory.
TPL-002-0b	R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast system Demands.	N/A	N/A	N/A	The responsible entity has failed to produce evidence of a valid current or past study and/or system simulation testing reflecting analysis over a range of forecast system demands.
TPL-002-0b	R1.3.7.	Demonstrate that system performance meets Category B contingencies.	N/A	N/A	N/A	No past or current study results exist showing Category B

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						contingency system analysis.
TPL-002-0b	R1.3.8.	Include existing and planned facilities.	The responsible entity's transmission model used for past or current studies and/or system simulation testing properly reflects existing facilities, but is deficient in reflecting planned facilities.	The responsible entity's transmission model used for past or current studies and/or system simulation testing properly reflects planned facilities, but is deficient in reflecting existing facilities.	N/A	The responsible entity's transmission model used for past or current studies and/or system simulation testing is deficient in reflecting existing AND planned facilities.
TPL-002-0b	R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	N/A	N/A	N/A	The responsible entity has failed to ensure in a past or current study and/or system simulation testing that sufficient reactive power resources are available to meet required system performance.
TPL-002-0b	R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	N/A	N/A	The responsible entity's transmission model used for past or current studies is deficient with respect to the effects of planned protection systems, including any backup or redundant systems.	The responsible entity's transmission model used for past or current studies is deficient with respect to the effects of existing protection systems, including any backup or redundant systems.
TPL-002-0b	R1.3.11.	Include the effects of existing and planned control devices.	N/A	N/A	The responsible entity's transmission model used for past or current studies is deficient with respect	The responsible entity's transmission model used for past or current studies is deficient with respect

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					to the effects of planned control devices.	to the effects of existing control devices.
TPL-002-0b	R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.	N/A	N/A	N/A	The responsible entity's transmission model used for past or current studies is deficient with respect to the inclusion of planned maintenance outages of bulk electric transmission facilities.
TPL-002-0b	R1.4.	Address any planned upgrades needed to meet the performance requirements of Category B of Table I.	N/A	N/A	N/A	The responsible entity has failed to demonstrate that a corrective action plan exists in order to satisfy Category B planning requirements.
TPL-002-0b	R1.5.	Consider all contingencies applicable to Category B.	The responsible entity has considered the NERC Category B contingencies applicable to their system, but was deficient with respect to 25% or less of all applicable contingencies.	The responsible entity has considered the NERC Category B contingencies applicable to their system, but was deficient with respect to more than 25% but less than 50% of all applicable contingencies.	The responsible entity has considered the NERC Category B contingencies applicable to their system, but was deficient with respect to more than 50% but less than 75% of all applicable contingencies.	The responsible entity has considered the NERC Category B contingencies applicable to their system, but was deficient 75% or more of all applicable contingencies.
TPL-002-0b	R2.	When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:	N/A	The responsible entity has failed to review the continuing need for previously identified facility	The responsible entity provided documented evidence of corrective action plans in order to satisfy Category B	The responsible entity has failed to provide documented evidence of corrective action plans in order to

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				additions through subsequent annual assessments. (R2.2)	planning requirements, but failed to include a implementation schedule with in-service dates (R2.1.1 and R2.1.2) OR The responsible entity failed to consider necessary lead times to implement its corrective action plan. (R2.1.3)	satisfy Category B planning requirements. (R2.1)
TPL-002-0b	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	N/A	N/A	N/A	N/A
TPL-002-0b	R2.1.1.	Including a schedule for implementation.	N/A	N/A	N/A	N/A
TPL-002-0b	R2.1.2.	Including a discussion of expected required in-service dates of facilities.	N/A	N/A	N/A	N/A
TPL-002-0b	R2.1.3.	Consider lead times necessary to implement plans.	N/A	N/A	N/A	N/A
TPL-002-0b	R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	N/A	N/A	N/A	N/A
TPL-002-0b	R3.	The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.	N/A	The responsible entity documented the results of its reliability assessments and corrective plans but did not annually provide them to its respective NERC	N/A	The responsible entity DID NOT document the results of its annual reliability assessments and corrective plans AND did not annually provide them to its

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Regional Reliability Organization(s) as required by the Regional Reliability Organization.		respective NERC Regional Reliability Organization(s) as required by the Regional Reliability Organization.
TPL-003-0a	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:	The responsible entity is non-compliant with 25% or less of the sub-components.	The responsible entity is non-compliant with more than 25% but less than 50% of the sub-components.	The responsible entity is non-compliant with 50% or more but less than 75% of the sub-components.	The responsible entity is non-compliant with 75% or more of the sub-components.
TPL-003-0a	R1.1.	Be made annually.	N/A	N/A	N/A	The assessments were not made on an annual basis.
TPL-003-0a	R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	The responsible entity has failed to demonstrate a valid assessment for the long-term period, but a valid assessment for the near-term period exists.	The responsible entity has failed to demonstrate a valid assessment for the near-term period, but a valid assessment for the long-term period exists.	N/A	The responsible entity has failed to demonstrate a valid assessment for the near-term period AND long-term planning period.
TPL-003-0a	R1.3.	Be supported by a current or past study and/or system simulation testing that	The responsible entity is non-compliant with	The responsible entity is non-compliant with	The responsible entity is non-compliant with	The responsible entity is non-compliant with

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	25% or less of the sub-components.	more than 25% but less than 50% of the sub-components.	50% or more but less than 75% of the sub-components.	75% or more of the sub-components.
TPL-003-0a	R1.3.1.	Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	N/A	The responsible entity provided evidence through current or past studies that selected NERC Category C contingencies were evaluated, however, no rational was provided to indicate why the remaining Category C contingencies for their system were not evaluated.	N/A	The responsible entity did not provided evidence through current or past studies to indicate that any NERC Category C contingencies were evaluated.
TPL-003-0a	R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	N/A	N/A	N/A	The responsible entity has failed to cover critical system conditions and study years as deemed appropriate.
TPL-003-0a	R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	The responsible entity's most recent long-term studies (and/or system simulation testing) were not performed in the most recent annual	The responsible entity's most recent near-term studies (and/or system simulation testing) were not performed in the most recent	N/A	The responsible entity's most recent near-term studies (and/or system simulation testing) AND most recent long-term studies

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			period AND significant system changes (actual or proposed) indicate that past studies (and/or system testing) are no longer valid.	annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system testing) are no longer valid.		(and/or system testing) were not performed in the most recent annual period AND significant system changes (actual or proposed) indicate that past studies (and/or system simulation testing) are no longer valid.
TPL-003-0a	R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	N/A	N/A	N/A	The responsible entity failed to produce evidence of a past or current year long-term study and/or system simulation testing (beyond 5-year planning horizon) when past or current year near-term studies and/or system testing show marginal conditions that may require longer lead-time solutions.
TPL-003-0a	R1.3.5.	Have all projected firm transfers modeled.	The system model(s) used for current or past analysis did not properly represent up to (but less than) 25% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 25% or more but less than 50% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 50% or more but less than 75% of the firm transfers to/from the responsible entity's service territory.	The system model(s) used for current or past analysis did not properly represent 75% or more of the firm transfers to/from the responsible entity's service territory.
TPL-003-0a	R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast	N/A	N/A	N/A	The responsible entity has failed to produce

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		system demands.				evidence of a valid current or past study and/or system simulation testing reflecting analysis over a range of forecast system demands.
TPL-003-0a	R1.3.7.	Demonstrate that System performance meets Table 1 for Category C contingencies.	N/A	N/A	N/A	No past or current study results exists showing Category C contingency system analysis.
TPL-003-0a	R1.3.8.	Include existing and planned facilities.	The responsible entity's transmission model used for past or current studies and/or system simulation testing properly reflects existing facilities, but is deficient in reflecting planned facilities.	The responsible entity's transmission model used for past or current studies and/or system simulation testing properly reflects planned facilities, but is deficient in reflecting existing facilities.	N/A	The responsible entity's transmission model used for past or current studies and/or system simulation testing is deficient in reflecting existing AND planned facilities.
TPL-003-0a	R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.	N/A	N/A	N/A	The responsible entity has failed to ensure in a past or current study and/or system simulation testing that sufficient reactive power resources are available to meet required system performance.
TPL-003-0a	R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	N/A	N/A	The responsible entity's transmission model used for past or current studies is	The responsible entity's transmission model used for past or current studies is

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
					deficient with respect to the effects of planned protection systems, including any backup or redundant systems.	deficient with respect to the effects of existing protection systems, including any backup or redundant systems.
TPL-003-0a	R1.3.11.	Include the effects of existing and planned control devices.	N/A	N/A	The responsible entity's transmission model used for past or current studies is deficient with respect to the effects of planned control devices.	The responsible entity's transmission model used for past or current studies is deficient with respect to the effects of existing control devices.
TPL-003-0a	R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.	N/A	N/A	N/A	The responsible entity's transmission model used for past or current studies is deficient with respect to the inclusion of planned maintenance outages of bulk electric transmission facilities.
TPL-003-0a	R1.4.	Address any planned upgrades needed to meet the performance requirements of Category C.	N/A	N/A	N/A	The responsible entity has failed to demonstrate that a corrective action plan exists in order to satisfy Category C planning requirements.
TPL-003-0a	R1.5.	Consider all contingencies applicable to Category C.	The responsible entity has considered the NERC Category C contingencies applicable to their	The responsible entity has considered the NERC Category C contingencies applicable to their	The responsible entity has considered the NERC Category C contingencies applicable to their	The responsible entity has considered the NERC Category C contingencies applicable to their

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			system, but was deficient with respect to 25% or less of all applicable contingencies.	system, but was deficient with respect to more than 25% but less than 50% of all applicable contingencies.	system, but was deficient with respect to more than 50% but less than 75% of all applicable contingencies.	system, but was deficient 75% or more of all applicable contingencies.
TPL-003-0a	R2.	When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:	N/A	The responsible entity has failed to review the continuing need for previously identified facility additions through subsequent annual assessments. (R2.2)	The responsible entity provided documented evidence of corrective action plans in order to satisfy Category C planning requirements, but failed to include an implementation schedule with in-service dates. (R2.1.1 and R2.1.2) OR The responsible entity failed to consider necessary lead times to implement its corrective action plan. (R2.1.3)	The responsible entity has failed to provide documented evidence of corrective action plans in order to satisfy Category C planning requirements. (R2.1)
TPL-003-0a	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	N/A	N/A	N/A	N/A
TPL-003-0a	R2.1.1.	Including a schedule for implementation.	N/A	N/A	N/A	N/A
TPL-003-0a	R2.1.2.	Including a discussion of expected required in-service dates of facilities.	N/A	N/A	N/A	N/A
TPL-003-0a	R2.1.3.	Consider lead times necessary to implement plans.	N/A	N/A	N/A	N/A
TPL-003-0a	R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the	N/A	N/A	N/A	N/A

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		continuing need for identified system facilities. Detailed implementation plans are not needed.				
TPL-003-0a	R3.	The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.	N/A	The responsible entity documented the results of its reliability assessments and corrective plans but did not annually provide them to its respective NERC Regional Reliability Organization(s) as required by the Regional Reliability Organization.	N/A	The responsible entity DID NOT document the results of its annual reliability assessments and corrective plans AND did not annually provide them to its respective NERC Regional Reliability Organization(s) as required by the Regional Reliability Organization.
TPL-004-0	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:	The responsible entity is non-compliant with one of the sub-components of requirement R1.3 (R1.3.1 through R1.3.9). OR The responsible entity has considered the NERC Category D contingencies applicable to their system, but was deficient with respect to 5% or less of all applicable contingencies. (R1.4)	The responsible entity is non-compliant with two of the sub-components of requirement R1.3 (R1.3.1 through 1.3.9). OR The responsible entity has considered the NERC Category D contingencies applicable to their system, but was deficient with respect to more than 5% up to (and including) 10% of all applicable contingencies. (R1.4)	The responsible entity is non-compliant with three of the sub-components of requirement R1.3 (R1.3.1 through 1.3.9). OR The responsible entity has considered the NERC Category D contingencies applicable to their system, but was deficient with respect to more than 10% up to (and including) 15% of all applicable contingencies. (R1.4)	The responsible entity did not perform the transmission assessments annually. (R1.1) OR The responsible entity has failed to demonstrate a valid assessment for the near-term planning period. (R1.2) OR The responsible entity is non-compliant with four or more of the sub-components of requirement R1.3 (R1.3.1 through 1.3.9).

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						OR The responsible entity has considered the NERC Category D contingencies applicable to its system, but was deficient with respect to more than 15% of all applicable contingencies. (R1.4)
TPL-004-0	R1.1.	Be made annually.	N/A	N/A	N/A	N/A
TPL-004-0	R1.2.	Be conducted for near-term (years one through five).	N/A	N/A	N/A	N/A
TPL-004-0	R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	N/A	N/A	N/A	N/A
TPL-004-0	R1.3.1.	Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	N/A	N/A	N/A	N/A
TPL-004-0	R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	N/A	N/A	N/A	N/A

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TPL-004-0	R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	N/A	N/A	N/A	N/A
TPL-004-0	R1.3.4.	Have all projected firm transfers modeled.	N/A	N/A	N/A	N/A
TPL-004-0	R1.3.5.	Include existing and planned facilities.	N/A	N/A	N/A	N/A
TPL-004-0	R1.3.6.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	N/A	N/A	N/A	N/A
TPL-004-0	R1.3.7.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	N/A	N/A	N/A	N/A
TPL-004-0	R1.3.8.	Include the effects of existing and planned control devices.	N/A	N/A	N/A	N/A
TPL-004-0	R1.3.9.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.	N/A	N/A	N/A	N/A
TPL-004-0	R1.4.	Consider all contingencies applicable to Category D.	N/A	N/A	N/A	N/A
TPL-004-0	R2.	The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.	N/A	The responsible entity documented the results of its reliability assessments but did not annually provide them to its respective NERC Regional Reliability Organization(s) as required by the Regional Reliability Organization.	N/A	The responsible entity DID NOT document the results of its annual reliability assessments AND did not annually provide them to its respective NERC Regional Reliability Organization(s) as required by the Regional Reliability Organization.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
VAR-001-2	R1.	Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.	The applicable entity did not ensure the development and/or maintenance and/or implementation of formal policies and procedures, as directed by the requirement, affecting 5% or less of their individual and neighboring areas voltage levels and Mvar flows.	The applicable entity did not ensure the development and/or maintenance and/or implementation of formal policies and procedures, as directed by the requirement, affecting between 5-10% of their individual and neighboring areas voltage levels and Mvar flows.	The applicable entity did not ensure the development and/or maintenance and/or implementation of formal policies and procedures, as directed by the requirement, affecting 10-15%, inclusive, of their individual and neighboring areas voltage levels and Mvar flows.	The applicable entity did not ensure the development and/or maintenance and/or implementation of formal policies and procedures, as directed by the requirement, affecting greater than 15% of their individual and neighboring areas voltage levels and Mvar flows.
VAR-001-2	R2.	Each Transmission Operator shall acquire sufficient reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load – within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.	The Transmission Operator acquired 95% but less than 100% of the reactive resources within its area needed to protect the voltage levels under normal and Contingency conditions including the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.	The Transmission Operator acquired 90% but less than 95% of the reactive resources within its area needed to protect the voltage levels under normal and Contingency conditions including the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.	The Transmission Operator acquired 85% but less than 90% of the reactive resources within its area needed to protect the voltage levels under normal and Contingency conditions including the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.	The Transmission Operator acquired less than 85% of the reactive resources within its area needed to protect the voltage levels under normal and Contingency conditions including the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.
VAR-001-2	R3.	The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.	N/A	N/A	N/A	The Transmission Operator did not specify criteria that exempts generators from compliance with

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						the requirements defined in Requirement 4, and Requirement 6.1. to all of the parties involved.
VAR-001-2	R3.1.	Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.	The Transmission Operator maintain the list of generators in its area that are exempt from following a voltage or Reactive Power schedule but is missing one or more entities. The missing entities shall represent less than 25% of those eligible for the list	The Transmission Operator maintain the list of generators in its area that are exempt from following a voltage or Reactive Power schedule but is missing two or more entities. The missing entities shall represent less than 50% of those eligible for the list	The Transmission Operator maintain the list of generators in its area that are exempt from following a voltage or Reactive Power schedule but is missing three or more entities. The missing entities shall represent less than 75% of those eligible for the list	The Transmission Operator maintain the list of generators in its area that are exempt from following a voltage or Reactive Power schedule but is missing four or more entities. The missing entities shall represent 75% or more of those eligible for the list.
VAR-001-2	R3.2.	For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.	The Transmission Operator failed to notify up to 25% of the associated Generator Owner of each generator that are on this exemption list.	The Transmission Operator failed to notify 25% up to 50% of the associated Generator Owners of each generator that are on this exemption list.	The Transmission Operator failed to notify 50% up to 75% of the associated Generator Owner of each generator that are on this exemption list.	The Transmission Operator failed to notify 75% up to 100% of the associated Generator Owner of each generator that are on this exemption list.
VAR-001-2	R4.	Each Transmission Operator shall specify a voltage or Reactive Power schedule [4] at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the	N/A	N/A	The Transmission Operator provide Voltage or Reactive Power schedules were for some but not all generating units as required in R4.	The Transmission Operator provide No evidence that voltage or Reactive Power schedules were provided to Generator Operators as required

[4] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
		associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).				in R4.
VAR-001-2	R5. (Retired)	Each Purchasing-Selling Entity and Load Serving Entity shall arrange for (self-provide or purchase) reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load– to satisfy its reactive requirements identified by its Transmission Service Provider.	The applicable entity did not arrange for reactive resources, as directed by the requirement, affecting 5% or less of its reactive requirements.	The applicable entity did not arrange for reactive resources, as directed by the requirement, affecting between 5-10% of its reactive requirements.	The applicable entity did not arrange for reactive resources, as directed by the requirement, affecting 10-15%, inclusive, of its reactive requirements.	The applicable entity did not arrange for reactive resources, as directed by the requirement, affecting greater than 15% of its reactive requirements.
VAR-001-2	R6.	The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.	The applicable entity did not know the status of all transmission reactive power resources, including the status of voltage regulators and power system stabilizers, as directed by the requirement, affecting 5% or less of the required resources.	The applicable entity did not know the status of all transmission reactive power resources, including the status of voltage regulators and power system stabilizers, as directed by the requirement, affecting between 5-10% of the required resources.	The applicable entity did not know the status of all transmission reactive power resources, including the status of voltage regulators and power system stabilizers, as directed by the requirement, affecting 10-15%, inclusive, of the required resources.	The applicable entity did not know the status of all transmission reactive power resources, including the status of voltage regulators and power system stabilizers, as directed by the requirement, affecting 15% or greater of required resources.
VAR-001-2	R6.1.	When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.	N/A	N/A	N/A	The Transmission Operator has not provided evidence to show that directives were issued to the Generator Operator to maintain or change either its voltage schedule or its Reactive Power

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Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
						schedule in accordance with R6.1.
VAR-001-2	R7.	The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.	The applicable entity was not able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow, affecting 5% or less of the required devices.	The applicable entity was not able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow, affecting between 5-10% of the required devices.	The applicable entity was not able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow, affecting 10-15%, inclusive, of the required devices.	The applicable entity was not able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow, affecting greater than 15% of the required devices.
VAR-001-2	R8.	Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.	The applicable entity did operate or direct the operation of capacitive and inductive reactive resources or load shedding within its area, as directed by the requirement, affecting 5% or less of the required resources.	The applicable entity did operate or direct the operation of capacitive and inductive reactive resources or load shedding within its area, as directed by the requirement, affecting between 5-10% of the required resources.	The applicable entity did operate or direct the operation of capacitive and inductive reactive resources or load shedding within its area, as directed by the requirement, affecting 10-15%, inclusive, of the required resources.	The applicable entity did operate or direct the operation of capacitive and inductive reactive resources or load shedding within its area, as directed by the requirement, affecting greater than 15% of the required resources.
VAR-001-2	R9.	Each Transmission Operator shall maintain reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load– to support its voltage under first Contingency conditions.	The Transmission Operator maintains 95% or more of the reactive resources needed to support its voltage under first Contingency conditions.	The Transmission Operator maintains 85% or more but less than 95% of the reactive resources needed to support its voltage under first Contingency conditions.	The Transmission Operator maintains 75% or more but less then 85% of the reactive resources needed to support its voltage under first Contingency conditions.	The Transmission Operator maintains less than 75% of the reactive resources needed to support its voltage under first Contingency conditions.
VAR-001-2	R9.1.	Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.	The applicable entity did not disperse and/or locate the reactive resources, as directed in	The applicable entity did not disperse and/or locate the reactive resources, as	The applicable entity did not disperse and/or locate the reactive resources, as directed	The applicable entity did not disperse and/or locate the reactive resources, as directed

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			the requirement, affecting 5% or less of the resources.	directed in the requirement, affecting between 5-10% of the resources.	in the requirement, affecting 10-15%, inclusive, of the resources.	in the requirement, affecting greater than 15% of the resources.
VAR-001-2	R10.	Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.	The applicable entity did not correct the IROL or SOL violations and/or complete the required IROL or SOL violation reporting, as directed by the requirement, affecting 5% or less of the violations.	The applicable entity did not correct the IROL or SOL violations and/or complete the required IROL or SOL violation reporting, as directed by the requirement, affecting between 5-10% of the violations.	The applicable entity did not correct the IROL or SOL violations and/or complete the required IROL or SOL violation reporting, as directed by the requirement, affecting 10-15%, inclusive, of the violations.	The applicable entity did not correct the IROL or SOL violations and/or complete the required IROL or SOL violation reporting, as directed by the requirement, affecting greater than 15% of the violations.
VAR-001-2	R11.	After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.	The Transmission Operator provided documentation to the Generator Owner specifying required step-up transformer tap changes and a timeframe for making these changes, but failed to provide technical justification for these changes.	The Transmission Operator provided documentation to the Generator Owner specifying required step-up transformer tap changes, but failed to provide a timeframe for making these changes and technical justification for these changes.	The Transmission Operator failed to provide documentation to the Generator Owner specifying required step-up transformer tap changes, a timeframe for making these changes, and technical justification for these changes.	N/A
VAR-001-2	R12.	The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.	N/A	N/A	N/A	The Transmission Operator has failed to direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

Complete Violation Severity Level Matrix (VAR)
Encompassing All Commission-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
VAR-002-1.1b	R1.	The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.	N/A	N/A	N/A	The responsible entity did not operate each generator in the automatic voltage control mode and failed to notify the Transmission Operator as identified in R1.
VAR-002-1.1b	R2.	Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings. [1] as directed by the Transmission Operator	When directed by the Transmission Operator to maintain the generator voltage or reactive power output the Generator Operator failed to meet the directed values by 5% or less.	When directed by the Transmission Operator to maintain the generator voltage or reactive power output the Generator Operator failed to meet the directed values by more than 5% up to (and including) 10% OR When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or	When directed by the Transmission Operator to maintain the generator voltage or reactive power output the Generator Operator failed to meet the directed values by more than 10% up to (and including) 15%	When directed by the Transmission Operator to maintain the generator voltage or reactive power output the Generator Operator failed to meet the directed values by more than 15%. OR When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Reactive Power schedule directed by the Transmission Operator. OR The Generator Operator failed to provide an explanation of why the voltage schedule could not be met.		directed by the Transmission Operator and the Generator Operator failed to provide an explanation of why the voltage schedule could not be met.
VAR-002-1.1b	R2.1.	When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.	N/A	N/A	N/A	N/A
VAR-002-1.1b	R2.2.	When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.	N/A	N/A	N/A	N/A
VAR-002-1.1b	R3.	Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:	N/A	N/A	The Generator Operator failed to notify the Transmission Operator within 30 minutes of the information as specified in either R3.1 or R3.2	The Generator Operator failed to notify the Transmission Operator within 30 minutes of the information as specified in both R3.1 and R3.2
VAR-002-1.1b	R3.1.	A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.	N/A	N/A	N/A	N/A

Complete Violation Severity Level Matrix (VAR)
Encompassing All Commission-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
VAR-002-1.1b	R3.2.	A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.	N/A	N/A	N/A	N/A
VAR-002-1.1b	R4.	The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner one of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 30, but less than or equal to 35 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner two of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 35, but less than or equal to 40 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner three of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than 40, but less than or equal to 45 calendar days of the request.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner any of the types of data as specified in R4.1.1 and R 4.1.2 and 4.1.3 and 4.1.4 OR The information was provided in more than 45 calendar days of the request.
VAR-002-1.1b	R4.1.	For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:	N/A	N/A	N/A	N/A
VAR-002-1.1b	R4.1.1.	Tap settings.	N/A	N/A	N/A	N/A
VAR-002-1.1b	R4.1.2.	Available fixed tap ranges.	N/A	N/A	N/A	N/A
VAR-002-1.1b	R4.1.3.	Impedance data.	N/A	N/A	N/A	N/A
VAR-002-1.1b	R4.1.4.	The +/- voltage range with step-change in % for load-tap changing transformers.	N/A	N/A	N/A	N/A

Complete Violation Severity Level Matrix (VAR)
Encompassing All Commission-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
VAR-002-1.1b	R5.	After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.	N/A	N/A	N/A	The responsible entity failed to ensure that transformer tap positions were changed according to the specifications provided by the Transmission Operator when said actions would not have violated safety, an equipment rating, a regulatory requirement, or a statutory requirement.
VAR-002-1.1b	R5.1.	If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.	N/A	N/A	N/A	The responsible entity failed to notify the Transmission Operator and to provide technical justification.
VAR-002-WECC-1	R1.	Generator Operators and Transmission Operators shall have AVR in service and in automatic voltage control mode 98% of all operating hours for synchronous generators or synchronous condensers. Generator Operators and Transmission Operators may exclude hours for R1.1 through R1.10 to achieve the 98% requirement. [*See Standard pdf for R1.1 through R1.10*]	AVR is in service less than 98% but at least 90% or more of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.	AVR is in service less than 90% but at least 80% or more of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.	AVR is in service less than 80% but at least 70% or more of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.	AVR is in service less than 70% of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.
VAR-002-WECC-1	R2.	Generator Operators and Transmission Operators shall have documentation identifying the number of hours excluded for each requirement in R1.1 through R1.10.	There shall be a Lower Level of non-compliance if documentation is incomplete with any requirement R1.1	There shall be a Moderate Level of non-compliance if the Generator Operator does not have documentation to	N/A	N/A

Complete Violation Severity Level Matrix (VAR)
Encompassing All Commission-Approved Reliability Standards

Standard Number	Requirement Number	Text of Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
			through R1.10.	demonstrate compliance with any requirement R1.1 through R1.10.		
VAR-501-WECC-1	R1.	Generator Operators shall have PSS in service 98% of all operating hours for synchronous generators equipped with PSS. Generator Operators may exclude hours for R1.1 through R1.12 to achieve the 98% requirement. [*See Standard pdf for R1.1 through R1.12*]	PSS is in service less than 98% but at least 90% or more of all hours during which the synchronous generating unit is on line for each calendar quarter.	PSS is in service less than 90% but at least 80% or more of all hours during which the synchronous generating unit is on line for each calendar quarter.	PSS is in service less than 80% but at least 70% or more of all hours during which the synchronous generating unit is on line for each calendar quarter.	PSS is in service less than 70% of all hours during which the synchronous generating unit is on line for each calendar quarter.
VAR-501-WECC-1	R2.	Generator Operators shall have documentation identifying the number of hours excluded for each requirement in R1.1 through R1.12.	There shall be a Lower Level of non-compliance if documentation is incomplete with any requirement R1.1 through R1.12.	There shall be a Moderate Level of non-compliance if the Generator Operator does not have documentation to demonstrate compliance with any requirement R1.1 through R1.12.	N/A	N/A

Complete Violation Severity Level Matrix (VAR)
Encompassing All Commission-Approved Reliability Standards

NERC Reliability Standards VSL Change History Table:

Date	Standard	Requirement	Action
9/25/12	BAL-005-0.2b, EOP-001-0.1b, EOP-002-3.1, PER-001-0.2 & TOP-002-2.1b		FERC approved Errata - Added
TBD	BAL-005-0.2b, CIP-001-2a, CIP-003-3, CIP-003-4, CIP-005-3a, CIP-005-4a, CIP-007-3, CIP-007-4, EOP-004-1, FAC-002-1, FAC-008-1, FAC-008-3, FAC-010-2.1, FAC-011-2, FAC-013-2, INT-007-1, IRO-016-1, NUC-001-2, PRC-010-0, PRC-022-1, VAR-001-2		Various VSLs retired as part of the Paragraph 81 project (Project 2013-02)

A. Introduction

1. Title: Cyber Security — Critical Cyber Asset Identification

2. Number: CIP-002-3

3. Purpose: NERC Standards CIP-002-3 through CIP-009-3 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3 requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. Applicability:

4.1. Within the text of Standard CIP-002-3, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator.

4.1.2 Balancing Authority.

4.1.3 Interchange Authority.

4.1.4 Transmission Service Provider.

4.1.5 Transmission Owner.

4.1.6 Transmission Operator.

4.1.7 Generator Owner.

4.1.8 Generator Operator.

4.1.9 Load Serving Entity.

4.1.10 NERC.

4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-002-3:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

B. Requirements

R1. Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.

R1.1. The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.

R1.2. The risk-based assessment shall consider the following assets:

R1.2.1. Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.

R1.2.2. Transmission substations that support the reliable operation of the Bulk Electric System.

R1.2.3. Generation resources that support the reliable operation of the Bulk Electric System.

R1.2.4. Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.

R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

R1.2.6. Special Protection Systems that support the reliable operation of the Bulk Electric System.

R1.2.7. Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.

R2. Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.

R3. Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a control center; or,

R3.3. The Cyber Asset is dial-up accessible.

R4. Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

C. Measures

M1. The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.

M2. The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.

M3. The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.

M4. The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documentation required by Standard CIP-002-3 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	January 16, 2006	R3.2 — Change "Control Center" to "control center"	03/24/06
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version number from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	Update

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Consideration of Comments

Interpretation 2012-INT-05
CIP-002-3 for OGE

The Interpretation 2012-INT-05 Drafting Team thanks all commenters who submitted comments on the Interpretation of CIP-002-3, Requirement R1, for OGE (Project 2012-INT-05). This interpretation was posted for a 30-day public comment period from June 27, 2012 through July 27, 2012. Stakeholders were asked to provide feedback on the interpretation through a special electronic comment form. There were 30 sets of comments, including comments from approximately 100 different people from approximately 90 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director, Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

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Index to Questions, Comments, and Responses

1. Do you agree with this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language. 8

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

2.	Group	Steve Alexanderson P.E.	Western Small Entity Comment Group			X	X					X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Eric Scott	City of Palo Alto	WECC	3
2.	Russ Schneider	Flathead Electric	WECC	3, 4
3.	Dale Dunckel	Okanogan PUD	WECC	1
4.	Russell A. Noble	Cowlitz County PUD No. 1	WECC	3, 4, 5
5.	Ronald Sporseen	Blachly-Lane Electric Cooperative	WECC	3
6.	Ronald Sporseen	Central Electric Cooperative	WECC	3
7.	Ronald Sporseen	Consumers Power	WECC	3, 1
8.	Ronald Sporseen	Clearwater Power Company	WECC	3
9.	Ronald Sporseen	Douglas Electric Cooperative	WECC	3
10.	Ronald Sporseen	Fall River Rural Electric Cooperative	WECC	3
11.	Ronald Sporseen	Northern Lights	WECC	3
12.	Ronald Sporseen	Lane Electric Cooperative	WECC	3
13.	Ronald Sporseen	Lincoln Electric Cooperative	WECC	3
14.	Ronald Sporseen	Raft River Rural Electric Cooperative	WECC	3

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

15.	Ronald Sporseen	Lost River Electric Cooperative	WECC	3
16.	Ronald Sporseen	Salmon River Electric Cooperative	WECC	3
17.	Ronald Sporseen	Umatilla Electric Cooperative	WECC	3
18.	Ronald Sporseen	Coos-Curry Electric Cooperative	WECC	3
19.	Ronald Sporseen	West Oregon Electric Cooperative	WECC	3
20.	Ronald Sporseen	Pacific Northwest Generating Cooperative	WECC	3, 4, 8
21.	Ronald Sporseen	Power Resources Cooperative	WECC	5

3.	Group	Christopher Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Richard Winters		WECC	1
2.	Forrest Krigbaum		WECC	1
3.	Scott Smith		WECC	1
4.	James Phillips		WECC	1
5.	Karin Butler		WECC	1
6.	Christine Jensen		WECC	1, 3, 5, 6

4.	Group	Bob Steiger	Salt River Project	X		X		X	X				

No additional members listed.

5.	Group	Will Smith	MRO NSRF	X	X	X	X	X	X				X

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM BREENE	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	3, 5, 6, 1
12.	MARIE KNOX	MISO	MRO	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
13. LEE KITTELSON	OTP	MRO	1, 3, 4, 5									
14. SCOTT BOS	MPW	MRO	1, 3, 5, 6									
15. TONY EDDLEMAN	NPPD	MRO	1, 3, 5									
16. MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6									
17. DAN INMAN	MPC	MRO	1, 3, 5, 6									
6. Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	M. McLean	FE	RFC	
2.	M. Koziel	FE	RFC	
3.	L. Raczkowski	FE	RFC	
4.	P. Buerling	FE	RFC	
5.	D. Hohlbaugh	FE	RFC	

7.	Group	Emily Pennel	Southwest Power Pool Regional Entity										X

No additional members listed.

8.	Group	Christine Hasha	ISO/RTO Council Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Gary DeShazo	CAISO	WECC	2
2.	Steve Myers	ERCOT	ERCOT	2
3.	Ben Li	IESO	NPCC	2
4.	Kathleen Goodman	ISONE	NPCC	2
5.	Dave Francis	MISO	RFC	2
6.	Greg Campoli	NYISO	NPCC	2

9.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
3.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6

10.	Group	Jason Marshall	ACES Power Marketing					X					

Additional Member	Additional Organization	Region	Segment Selection
1. John Shaver	Arizona Electric Power Cooperative/SW Transmission Cooperative	WECC	1, 4, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
2. Patrick Woods East Kentucky Power Cooperative SERC 1, 3, 5 3. Bill Watson Old Dominion Electric Cooperative RFC/SERC 3, 4 4. Megan Wagner Sunflower Electric Power Corporation SPP 1 5. Susan Sosbe Wabash Valley Power Association RFC/SERC 3													
11.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
12.	Individual	Shammara Hasty	Southern Company	X		X		X	X				
13.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
14.	Individual	Alan Rivaldo	Public Utility Commission of Texas									X	
15.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
16.	Individual	Jay Campbell	NV Energy	X		X	X	X					
17.	Individual	Oliver Burke	Entergy Services, Inc.	X		X		X	X				
18.	Individual	Thad Ness	American Electric Power	X		X		X	X				
19.	Individual	David Thorne	Pepco Holdings Inc.	X		X							
20.	Individual	Michelle R DAntuono	Ingleside Cogeneration LP					X					
21.	Individual	Michael Falvo	Independent Electricity System Operator		X								
22.	Individual	Grant Wilkerson	Westar Energy	X		X		X					
23.	Individual	Patrick Brown	Essential Power, LLC					X					
24.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
25.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
26.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
27.	Individual	Anthony Jablonski	ReliabilityFirst										X
28.	Individual	Scott Bos	Muscatine Power and Water	X		X		X	X				
29.	Individual	Terry Harbour	MidAmerican Energy Company	X		X		X	X				
30.	Individual	Mike Stanley	MEAG Power	X		X		X					

1. **Do you agree with this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.**

Summary Consideration: The Interpretation Drafting Team (IDT) carefully reviewed all comments in response to the posting of a formal comment period that ended July 27, 2012. In the draft interpretation, the IDT clarifies the meaning of CIP-002-3, Requirement R1.2.5 as it relates and applies to new technologies such as Advanced Meter Infrastructure (AMI). Commenters provided several points of constructive feedback for the IDT's consideration in modifying the draft interpretation in preparation for the next formal comment period and parallel initial ballot. Among the issues identified in comments were recommendations that the IDT amend its response and that it add detail to the response and clarify the response with improved wording. The IDT believes that a few of the commenters who disagreed with the interpretation disagreed due to a misunderstanding of the response, and the IDT has adopted several of the recommended wording changes. Several commenters stated that Load shed of 300 MW or greater is not the issue, but rather that the 300 MW is specifically purposed for BES function of automatic UVLS or UFLS. In response, the IDT agrees with the position that it is not the 300 MW threshold that triggers criticality, but rather what the 300 MW UVLS or UFLS functionally defines. There was a comment that the wording relating to "automatic" could be clarified. In response, the IDT considered the comment but determined that it is generally a well-understood term and would need to be incorporated within an entity's risk-based assessment methodology (RBAM) and processes. There were a few comments that stated the reference to annual is an incorrect citation. In response, the IDT has clarified references from Requirement R4 to Requirement R2 and from Requirement R1 to Requirement R1.2.5.

Organization	Yes or No	Question 1 Comment
Western Small Entity Comment Group	No	The AMI remote connect/disconnect feature described by OGE works at the service voltage level. The meters in question are manufactured with relays inside, so that direct metered services may individually be remotely connected or disconnected. The voltages involved are typically 120V to 480V. While it is true that such a system could be configured to disconnect enough services simultaneously to reach an aggregate exceeding 300MW, the limitations of section 215 of the FPA preclude any consideration of these

Organization	Yes or No	Question 1 Comment
		systems for the purposes of mandatory standards. While there may be some confusion regarding where the line between the Bulk Power System and local distribution lies exactly, the comment group believes these service voltage facilities are unquestionably on the local distribution side and cannot be subject to standards regardless of how they are configured. There can be no requirement to annually reconsider these systems as Critical Assets under the limitations provided by Congress.
Response: Thank you for your comment. Within the CIP standards and related security requirements, loss of Load is within the scope of NERC Reliability Standards as specified in the standards. As the interpretation identifies, if a registered entity has not purposed a system such as AMI to "automatically", which means without human operator initiatation, shed 300 MW or greater of Load it does not need to consider that system under their RBAM. If the equipment is placed on the transmission facilities, the purpose must be evaluated for possible inclusion in the RBAM.		
MRO NSRF	No	The NSRF does not agree that the IDT can clearly state that the AMI is not critical under R1.2.5. The IDT should not make the following statement of:"Applying these requirements to the remote connect or disconnect functionality associated with advanced metering infrastructure (AMI), the drafting team concludes in its interpretation that AMI is not a Critical Asset under R1.2.5 so long as the AMI is not designed to or cannot, without human operator intervention, shed a load of 300MW or more". The NSRF disagrees with this interpretation for the following reasons;1. R1.2.5 is written to specifically address "systems and facilities" that are "critical to automatic load shedding under a common control system capable of shedding 300 MW or more". Not that you have a threshold of "automatic load shedding under a common control system capable of shedding 300 MW or more". The use of 300 MW or more is a pseudo threshold. Consideration of "system and facilities" is the intent of the requirement. 2. Each applicable entity's RBAM should consider (R1.2) their "systems and facilities" that are critical to automatic load shedding...300 MW or more.

Organization	Yes or No	Question 1 Comment
		Upon consideration, the entity may or may not elect to identify the "system or facility" as a Critical Asset, based on their RBAM. 3. The NSRF believes CIP-002-3 is clearly written and that the IDT cannot determine if an Entity's AMI is a Critical Asset or not.
Response: Thank you for your response. The IDT agrees that CIP-002-3 is clearly written and that it cannot determine if an entity's AMI is a Critical Asset. The entity would make that determination by using its RBAM. **In response to OGE's question, the IDT is making the point that AMI is one potential method to shed Load and that the entity would need to determine in its RBAM if it had a system that could "automatically" shed Load and whether the system qualified as a Critical Asset under the terms of the standard.** **The IDT has also removed the following sentence to clarify the interpretation: "If it does, pursuant to Requirement R1.2, the Responsible Entity must consider that asset for identification as a Critical Asset under its RBAM required by CIP-002-3, Requirement R1."**		
Southwest Power Pool Regional Entity	No	The explanatory language of the interpretation is confusing and provides little clarification to the requesting entity. It provides misleading guidance regarding the distinction of "critical" to automatic load shed. It also could be misconstrued by a Responsible Entity in its present form to more broadly apply to all Smart Grid systems functionality in general, leading the entity to conclude that Smart Grid is excluded from the CIP standards. A system or facility is "critical" to load shedding when it is the system or facility that actually disconnects the load upon command of a system intended to perform load reduction as one of its functions, whether manual or automated. Automatic load shedding is that action that occurs without operator intervention, although it may be initiated by an operator under certain circumstances as further explained below. The "common control system" is that programmatic application communicating with and directing the actions of the systems or facilities disconnecting the load. The common control system may be "capable" of shedding more than 300 MW of load

Organization	Yes or No	Question 1 Comment
		while in normal practice less than 300 MW is shed at one time. It is the capability and not the normal practice that must be evaluated. The Responsible Entity must take all of these factors into consideration when determining whether a Cyber Asset meets the R1.2.5 criterion. The Responsible Entities generally recognize that protective relays configured to perform automatic under-frequency or under-voltage load shed meet the criterion of "critical to automatic load shedding" and the entities can readily determine if these devices are capable of shedding 300 MW or more either individually or under a common control system. Responsible Entities generally overlook upstream systems and their potential impact if their capabilities are misused. Responsible Entities often view their SCADA/EMS load shed programs as "manual," not "automatic," without evaluating the actual functionality. While an operator may initiate the load shed by entering a target MW, some load shed programs then automatically perform all of the analysis required to shed sufficient load blocks to attain the target reduction. It is automatic in the sense that the operator could manually open up all of the breakers in the load block scheme, one at a time, to achieve the same result. Similarly, while an operator may initiate rotating load shed by entering a target reduction value, some load shed programs perform all of the necessary steps to automatically cycle through the load blocks until instructed to stop. In a similar manner, Smart Grid systems are often capable of multiple functions including demand response (essentially automatic load shed made possible by curtailing selected appliance load) as well as remote customer meter connect/disconnect (clearly a manual operation and the specific issue at hand). If the demand response functionality of the Smart Grid system is capable of reducing load by 300 MW or more, then it must be considered a Critical Cyber Asset even if load shed is not its "primary" function. The AMI Remote Disconnect function is theoretically capable of being misused to shed 300 MW or more, however that would be done one meter at a time given the programmatic capability

Organization	Yes or No	Question 1 Comment
		of the system. AMI Remote Disconnect is considered to be a manual function - one operator action against one meter. AMI Remote Disconnect is not and cannot be construed to be load shed functionality. The interpretation can be improved, clarified, and simplified by eliminating the explanatory discussion and simply responding to the narrowly focused question asked by OG&E. OG&E specifically asks if the AMI Remote Disconnect function is a system or facility critical to automatic load shedding under a common control system capable of shedding 300 MW or more. The similarly focused response should simply state that while other functions of a Smart Grid AMI system may be capable of automatically shedding 300 MW or more of load, the specific AMI Remote Disconnect function is not a system or facility critical to load shed. An AMI system specifically built and configured to only perform the Remote Disconnect function does not meet the criterion found in CIP-002-3, Requirement R1.2.5.
Response: Thank you for your response. The IDT did not answer the specific AMI question because the role of the IDT is to answer questions concerning the interpretation of the standards and not to answer specific technological applications under the standard. Each entity needs to understand their system and evaluate it under their RBAM. The IDT has made several changes to the wording of its response to make it clearer, however, including language specifying that "an AMI system specifically built and configured to perform the Remote Disconnect function that does not automatically shed load without human operator initiation would not meet the criteria found in CIP-002-3, Requirement R1.2.5."		
Public Utility Commission of Texas	No	I essentially agree with the interpretation but checked "No" because I think the last sentence needs more clarity. The last part of the last sentence reads "...so long as the AMI is not designed to or cannot, without human operator intervention, shed a load of 300MW or more."I propose that the sentence in the interpretation be reworded to read: "as long as the AMI is not designed to shed a load of 300MW or more, or at least cannot do so without human operator intervention."
Response: Thank you for your response. The interpretation has been reworded to improve clarity and to specify that it must be		

Organization	Yes or No	Question 1 Comment
both automatically and without human operator intervention. The IDT notes that the language quoted in the comment was from the background information that the IDT provided and is not part of the interpretation itself.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP believes that the interpretation developed by the drafting team comes to the correct conclusion - that OGE's Smart Grid AMI function is not likely going to be identified as a BES Critical Asset. However, it puts the onus on the Responsible Entity to assess the service loss caused by an asset which clearly does not serve a BES function. This effectively expands the scope of the RBAM to apply to equipment that has nothing to do with critical BES functions as they are presently understood. Perhaps of more concern, the drafting team has ignored the results of extensive investigation into this issue which took place during the development of CIP Version 4. In CIP-002-4, the corresponding bright-line criterion states the following:"1.13. Each system or Facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program."This language is unambiguous and fully addresses the concern by OGE that their Smart Grid Advanced Meter Infrastructure (AMI) could be considered a Smart Grid remote meter disconnect function to be a Critical Asset because it can be configured to shed an aggregate load greater than 300 MW. The intent is to identify UVLS and UFLS systems that are a part of a regional reliability program - not delve into remote meter connections. We are aware that NERC Compliance has taken a position that the bright-line criteria cannot replace the RBAM until CIP Version 4 takes effect in 2014. We are puzzled why an superior system which has been vetted by industry and approved by FERC should be out-of-bounds - especially since the stance does not appear to be related to reliability. Furthermore, there are costs to ambiguity - every dollar spent evaluating the AMI system takes away from other reliability needs. In addition, there is a hidden cost that a conservative reading of the interpretation will lead Responsible Entities to conclude that

Organization	Yes or No	Question 1 Comment
		cyber-hardening is necessary for Smart Grid technologies. If this becomes a wide-spread belief, then many will choose to delay or not deploy the capability. There are enormous societal benefits to Smart Grid (e.g.; intelligent energy conservation) that are at stake - so we urge the project team to take a more definitive stance that AMI systems are not part of the BES and do not need to be considered as Critical Assets.
Response: Thank you for your response. The IDT notes that a Responsible Entity's evaluation and application of its RBAM is necessarily driven by facts and circumstances. Furthermore, the IDT is responding to OGE's request within the context of CIP Versions 1 through 3, which include the RBAM, and based on Guidelines for Interpretation Drafting Teams. This interpretation will not apply to Version 4, which does not use the RBAM, and the IDT does not interpret the previous versions with the information that does not appear in the standard.		
Duke Energy	No	While the interpretation arrives at the correct conclusion, the logic in the third paragraph of the response is needlessly complicated and not supported by a reading of the plain language of R4. Suggested rewording of the third paragraph: "During the identification and documentation of the risk-based assessment methodology used to identify Critical Assets required by R1, a Responsible Entity shall consider "Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more" as specified in R1.2.5. R2 then requires the entity to apply this risk-based assessment methodology annually to identify Critical Assets. If a system or facility is not "critical to" automatically shedding load, or the common control system is not "capable of" automatically shedding 300 MW or more, the asset is not required to be considered in the methodology per R1.2.5, and the asset may not be a Critical Asset."Also, in the fifth paragraph of the response, insert the word "automatically" before the word "shedding".
Response: Thank you for your response. The IDT used your language to rewrite its response.		

Organization	Yes or No	Question 1 Comment
Muscatine Power and Water	No	MPW does not agree that the IDT can clearly state that the AMI is not critical under R1.2.5. The IDT should not make the following statement of:"Applying these requirements to the remote connect or disconnect functionality associated with advanced metering infrastructure (AMI), the drafting team concludes in its interpretation that AMI is not a Critical Asset under R1.2.5 so long as the AMI is not designed to or cannot, without human operator intervention, shed a load of 300MW or more". MPW disagrees with this interpretation for the following reasons; 1. R1.2.5 is written to specifically address "systems and facilities" that are "critical to automatic load shedding under a common control system capable of shedding 300 MW or more". Not that you have a threshold of "automatic load shedding under a common control system capable of shedding 300 MW or more". The use of 300 MW or more is a pseudo threshold. Consideration of "system and facilities" is the intent of the requirement. 2. Each applicable entity's RBAM should consider (R1.2) their "systems and facilities" that are critical to automatic load shedding...300 MW or more. Upon consideration, the entity may or may not elect to identify the "system or facility" as a Critical Asset, based on their RBAM. 3. MPW believes CIP-002-3 is clearly written and that the IDT cannot determine if an Entity's AMI is a Critical Asset or not.
Response: Thank you for your response. The IDT agrees that CIP-002-3 is clearly written and that it cannot determine if an entity's AMI is a Critical Asset. The entity would make that determination by using its RBAM. **In response to OGE's question, the IDT is making the point that AMI is potentially one of a number of potential methods to shed Load and that the entity would need to determine via its RBAM if it had a system that could "automatically" shed Load and whether the system qualified as a CA under the terms of the standard.**		

Organization	Yes or No	Question 1 Comment
ACES Power Marketing	No	Conceptually, we agree with the interpretation. We offer a few refinements to further improve the interpretation. 1) The first sentence in the third paragraph should reference CIP-002-3 R2 not CIP-002-3 R4. The annual application of the risk-based assessment (RBAM) is not required in CIP-002-3 R4 as interpretation implies. Rather it is required in CIP-002-3 R2. CIP-002-3 R4 requires the senior manager to approve the RBAM, list of Critical Assts, and list of Critical Cyber Assets. While this approval likely will require some level of review, it will be a management review not the annual RBAM application. Thus, "Each year, during the annual approval required under CIP-002-3, Requirement R4," should become "Each year per CIP-002-3 Requirement R2". 2) The interpretation needs to match the order of the application of the requirements more closely. In the first sentence of the third paragraph, we suggest "a Responsible Entity must reevaluate whether it has systems or facilities, as specified in Requirement R1.2.5" should be changed to a "Responsible Entity must annually apply its RBAM to identify if any system or facilities, as specified in Requirement R1.2.5, are Critical Assets". 3) In the last sentence of the third paragraph, "the asset may not be a Critical Asset" should be changed to "the asset is not required to be considered a potential Critical Asset in its RBAM through CIP-002-3 R1.2.5." Otherwise, it is not perfectly clear that the responsible entity does not have to consider these "systems and facilities" as potential Critical Assets in its RBAM. Otherwise, the responsible entity may be left confused if they are obligated to consider these "systems and

Organization	Yes or No	Question 1 Comment
		facilities". 4) In the third line of the third paragraph, R1.2 should be R1.2.5. 5) The fourth paragraph needs some modifications. "Asset" should be "Critical Asset and CIP-002-3, Requirement R1 should refer to Requirement R2. R1 does not compel identification of any assets of any type. Rather it simply requires that the responsible entity to identify and document an RBAM. 6) A more direct statement is needed to clarify that if the "systems and facilities" are not automatic and require operator (or user) intervention that they are not subject to R1.2.5. The last statement in the Background Information section of the comment form is much clearer than the interpretation and could be adopted. It reads: "Applying these requirements to the remote connect or disconnect functionality associated with advanced metering infrastructure (AMI), the drafting team concludes in its interpretation that AMI is not a Critical Asset under R1.2.5 so long as the AMI is not designed to or cannot, without human operator intervention, shed a load of 300MW or more." This really clarifies what is meant by automatic. "Systems and facilities" could be substituted for AMI to make the statement technology neutral.
Response: Thank you for your response. The IDT took your comments into consideration along with the recommendations made by other commenters and reworded its response. Q1 – Q4: The third paragraph has been reworded. Q5: Your recommended changes have been adopted. Q6: Based on its understanding of Guidelines for Interpretation Drafting Teams, the IDT believes that such a statement is more appropriately included as part of the background information as opposed to part of the interpretation itself. The IDT intends for the interpretation to provide an input to the RBAM consideration process, not to prescribe an outcome. However, based in part on this suggestion, the IDT did further clarify in the interpretation itself that "an AMI system specifically built and configured to perform the Remote Disconnect function that does not automatically shed load		

Organization	Yes or No	Question 1 Comment
without human operator initiation would not meet the criteria found in CIP-002-3, Requirement R1.2.5."		
Bonneville Power Administration	Yes	BPA agrees with this interpretation with the understanding that a System Operator does not have access to the AMI and a one push button cannot achieve 300MW or more.
Response: Thank you for your response. The IDT agrees with your comment and notes that "a one push button" is not automatic.		
Salt River Project	Yes	SRP supports OGE's interpretation that SmartGrid AMI systems are not designed to allow for automatic load shedding.
Response: Thank you for your response and supportive comment.		
FirstEnergy	Yes	We fundamentally agree with the interpretation but offer the following comments and suggested wording: Although the interpretation request is specific to CIP-002-3, the team should consider whether or not their response is within the spirit of CIP-002-4 bright line Attachment 1 criterion 1.13 which reads: "Each system or Facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program." The subtle difference between version 3 and version 4 is that version 4 seems to include only those systems associated with UVLS and UFLS and not more generically as in the wording of version 3 and is the reason the requestor indicates that the AMI system is not relied upon for its UVLS and UFLS functionality. Another key clarification the bright line made was in the phrase "without human operator initiation". It sounds like AMIs are intended as a convenience or efficiency gain of dropping load from a central

Organization	Yes or No	Question 1 Comment
		location and would be operator initiated. The risk of a hacker just breaking into some system and dropping load is likely not a BES reliability risk. Additionally, if the hacker would compromise the AMI such that the load can not be shed from a centralized location (assuming operator initiated) still does not impact BES reliability since the transmission operator would have EMS controls as a back-up for shedding load, even if the load shed is for a reliability purpose and not an economic need. The reason the bright line criterion 1.13 landed where it did is that the real risk is that a load shedding scheme performing automatic load shed during a critical frequency or voltage collapse cannot be compromised and must be available to act when automatic controls triggering those systems are met. In light of our comments, we suggest a slight modification to the last paragraph of the interpretation to include the phrase "without human operator initiation shed load for a critical BES reliability purpose" and suggest the following wording for the last paragraph:"Therefore, if a system or facility such as AMI meets the specifications of Requirement 1.2.5 (i.e., is both capable of shedding 300 MW or more and is set up and purposed to automatically, without human operator initiation, shed load for a critical BES reliability purpose), the Responsible Entity should consider the system or facility for identification as a Critical Asset under its RBAM. Otherwise, the Responsible Entity is not required to consider the system or facility for identification as a Critical Asset."
Response: Thank you for your response. The IDT reworded the last paragraph using the main points of your recommendation.		
ISO/RTO Council Standards Review Committee	Yes	In regards to the Response section of the Interpretation, the SRC requests the correction(s) shown below. Response Section, page 2 "Each year, during the annual approval required under CIP-002-3, Requirement R2, a Responsible Entity must reevaluate whether it has systems or facilities, as specified in Requirement R1.2.5, that

Organization	Yes or No	Question 1 Comment
		are “critical to automatic load shedding under a common control system capable of shedding 300 MW or more.” If it does, pursuant to Requirement R1.2, the Responsible Entity must consider that asset for identification as a Critical Asset under its RBAM required by CIP-002-3, Requirement R1. If a system or facility is not “critical to” automatical shedding load, or the common control system is not “capable of” shedding 300 MW or more, the asset may not be a Critical Asset.” Explanation: Requirement R2 is the requirement for the annual application of the risk-based assessment methodology required in R1. Requirement 4 is only for approval and not for update or reevaluation. The change to “automatical” is a grammatical fix. Response Section, page 3 ”Therefore, if a system or facility such as AMI meets the specifications of Requirement 1.2.5 (i.e., is critical to automatic load shedding under a common control system and is capable of shedding 300 MW or more), the Responsible Entity should consider the system or facility for identification as a Critical Asset under its RBAM.” An entity should consider AMI under its RBAM if the equipment/facility has the requisite capability - i.e. capable of shedding 300 MW or more - despite whether the equipment/facilities are in fact purposed to perform that function in practice. The reason that capability, and not actual function, should be the determining factor is because if the equipment can be manipulated to manipulate load, despite its actual practical function, it should be assessed for criticality because it can affect system reliability. Explanation: The SRC requests the interpretation be modified consistent with the above revisions because if an AMI system is capable of shedding load, despite its actual functionality, it has the potential to negatively impact the BES in the event of misuse or security breach.
Response: Thank you for your response. The IDT notes that there is not a need for a grammar fix, as the standard uses the term “automatic,” and the IDT cannot change the standard itself.		

Organization	Yes or No	Question 1 Comment
Southern Company	Yes	Southern Company appreciates the opportunity to provide the following comments regarding the interpretation of CIP-002-3, Requirement 1. As part of the annual approval, the methodology and logic as required by NERC CIP - 002 is used to determined the list of assets critical to the reliability of the Bulk Electric System. Southern Company agrees that each entity should determine its Critical Assets, if any.
Response: Thank you for your response and supportive comments.		
Pepco Holdings Inc.	Yes	PHI supports the interpretation
Response: Thank you for your support of the interpretation.		
ReliabilityFirst	Yes	ReliabilityFirst generally agrees with the drafted interpretation but offers one minor comment for consideration. ReliabilityFirst believes there is an incorrect reference to “an annual approval” per CIP-002-3 R4 in the draft Interpretation. ReliabilityFirst believes the correct reference should be to the “annual application of the RBAM” located in CIP-002-3 R2.
Response: Thank you for your comment. The IDT clarified the references.		
MidAmerican Energy Company	Yes	MidAmerican Energy Company believes CIP-002-3, R1.2.5 is clear as written, but does not disagree with the proposed interpretation response.
Response: Thank you for your response.		
MEAG Power	Yes	
Northeast Power Coordinating Council	Yes	

Organization	Yes or No	Question 1 Comment
SPP Standards Review Group	Yes	
PacifiCorp	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
NV Energy	Yes	
Entergy Services, Inc.	Yes	
American Electric Power	Yes	
Independent Electricity System Operator	Yes	
Westar Energy	Yes	
Essential Power, LLC	Yes	
City of Austin dba Austin Energy	Yes	
South Carolina Electric and Gas	Yes	

END OF REPORT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

When completed, email this form to:
maureen.long@nerc.net
For questions about this form or for assistance in completing the form, call Maureen Long at 813-468-5998.

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard

Date submitted: 2/24/11

Contact information for person requesting the interpretation:

Name: John Rhea

Organization: OGE Energy Corp.

Telephone: 405-553-3445

E-mail: rheajd@oge.com

Identify the standard that needs clarification:

Standard Number (include version number): CIP-002-3

(example: PRC-001-1)

Standard Title: Cyber Security – Critical Cyber Asset Identification

Identify specifically what requirement needs clarification:

Requirement Number and Text of Requirement:

CIP-002-3 R1.2.5 - Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

Clarification needed: Based on the text above, an auditor could apply this standard to the Smart Grid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality. While the AMI system is not designed to perform automatic load shedding of 300 MW it could be repurposed to shed an aggregate load of 300 MW or more. However, it is important to note that the AMI remote disconnect function is not used for under-voltage load shedding or under-frequency load shedding as a part of the region's load shedding program.

The primary purpose of the AMI remote connect/disconnect function is to connect and disconnect individual retail electric customers from a central location rather than at the meter itself to enable substantial efficiency gains.

OGE would like NERC to clarify that a company's SmartGrid AMI functionality, which may be able to disconnect 300+ MW of load, is not considered a system or facility critical to automatic load shedding under a common control system capable of shedding 300 mw and therefore it should not be included in the Company's risk based methodology. OGE believes this clarification is appropriate because CIP-002-3 R1.2.5 was written to address under-voltage and under-frequency load shedding systems; SmartGrid AMI disconnect functionality pertains to neither.

Identify the material impact associated with this interpretation:
Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard. The AMI Remote Disconnect function has no impact on OGE's ability to participate in SPP's load shedding program. The cost of compliance for OGE alone is in the millions of dollars without any significant benefit to the reliability of the Bulk Electric System.

Project 2012-INT-05: Response to Request for an Interpretation of NERC Standard CIP-002-3 for the OGE Energy Corporation

The following interpretation of NERC Standard CIP-002-3 Cyber Security — Critical Cyber Asset Identification, Requirement R1.2.5, was developed by a project team from the CIP Interpretation Drafting Team.

Requirement Number and Text of Requirement

R1. Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.

R1.2. The risk-based assessment shall consider the following assets:

R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

Question

OGE Energy Corporation seeks clarification on the meaning of CIP-002-3, Requirement R1.2.5 as it relates to "SmartGrid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality."

In its response, the Interpretation Drafting Team will answer whether a company's SmartGrid AMI functionality, which may be able to disconnect more than 300 MW of load, is considered a system or facility critical to automatic load shedding under a common control system capable of shedding 300 MW or more under CIP-002-3, Requirement 1.2.5.

Response

In evaluating OGE's request, the Interpretation Drafting Team (IDT) clarifies the meaning of CIP-002-3, Requirement R1.2.5 as it relates and applies to new technologies such as AMI. CIP-002-3, Requirement R1.2.5, along with the context of the standard as a whole, informed development of this interpretation.

CIP-002-3, Requirement R1.2 specifies that the Responsible Entity's risk-based assessment methodology ("RBAM") "shall consider" the assets described in Requirement R1.2.5 ~~for identification as Critical Assets.~~ .

~~Each year, during~~During the ~~annual approval required under CIP-002-3, Requirement R4~~identification and documentation of the RBAM, a Responsible Entity ~~must reevaluate whether it has systems or~~shall consider "Systems and facilities~~, as specified in Requirement R1.2.5, that are "~~ critical to automatic load shedding under a common control system capable of shedding 300 MW or more~~." If it does, pursuant~~" as specified in Requirement R1.2.5. Requirement R2 then requires the entity to apply this RBAM annually to identify Critical Assets. If a system or facility does not meet the specifications of Requirement R1.2.5, the ~~Responsible Entity must~~RBAM is not required to consider that asset.
~~for identification as a~~
~~Critical Asset under its RBAM required by CIP-002-3, Requirement R1. If a system or facility is not "critical to" automatically shedding load, or the common control system is not "capable of" shedding 300 MW or more, the asset may not be a Critical Asset.~~

The Critical Asset identification method under CIP-002-3, Requirement R1 is based on a facts and circumstance-driven analysis and is not dependent exclusively on specific technology or specific types of systems or facilities.~~-~~ For instance, systems or facilities such as AMI may have the potential or capability to be set up to automatically shed load, but having that potential or capability does not necessarily mean that the system or facility performs the function as described in Requirement R1.2.5. Therefore, an AMI system specifically built and configured to perform the Remote Disconnect function that does not automatically shed load without human operator initiation would not meet the criteria found in CIP-002-3, Requirement R1.2.5.

~~Therefore, if a system or facility such as AMI meets the specifications of Requirement 1.2.5 (i.e., is both capable of shedding 300 MW or more and is set up and purposed to automatically shed load), the Responsible Entity should consider the system or facility for identification as a Critical Asset under its RBAM. Otherwise, the Responsible Entity is not required to consider the system or facility for identification as a Critical Asset.~~

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Standards Announcement

Project 2012-INT-05 Interpretation of CIP-002-3 for OGE

Formal Comment Period Now Open: November 6, 2012 – December 20, 2012
Ballot Pool Forming Now: November 6, 2012 – December 5, 2012

Upcoming
Initial Ballot: December 11 – 20, 2012

Now Available

A formal comment period for the interpretation of **CIP-002-3** – Cyber Security – Critical Cyber Asset Identification is open through 8 p.m. Eastern on **Thursday, December 20, 2012.** A ballot pool is being formed and the ballot pool window is open through 8 a.m. Eastern on **Wednesday, December 5, 2012** (*please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly*).

Instructions for Joining Ballot Pool(s)

Registered Ballot Body members must join the ballot pool to be eligible to vote in the balloting of the interpretation of CIP-002-3. Registered Ballot Body members may join the ballot pool at the following page: Join Ballot Pool

During the pre-ballot window, members of the ballot pool may communicate with one another by using the "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.)
The ballot pool list server for this ballot pool is: bp-2012-INT-05@nerc.com.

The ballot pool is open **through 8 a.m. Eastern on Thursday, December 20, 2012.**

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Thursday, December 20, 2012.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An initial ballot will be conducted December 11, 2012 through 8 p.m. Thursday, December 20, 2012.

Background

Oklahoma Gas and Electric (OGE) submitted a request for interpretation of CIP-002-3 asking for clarification of Requirement R1.2.5 in relation to SmartGrid AMI functionality. Clarification was requested that a company's SmartGrid AMI functionality, which may be able to disconnect 300+ MW

of load, is not considered a system or facility critical to automatic load shedding under a common control system capable of shedding 300 MW and therefore it should not be included in the company's risk-based methodology.

The drafting team has reviewed all comments submitted in the previous posting of the interpretation, and it has made changes in the interpretation in response to those comments.

To sign up for the plus list for this project to follow along with meetings and work products, please email Wendy Muller.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Development Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2012-INT-06 – Interpretation of CIP-003-3 for Consumers Energy

Formal Comment Period Open: November 9, 2012 – December 10, 2012

Now Available

A formal comment period for the interpretation of CIP-003 for Consumers Energy is open through **8 p.m. Eastern on Monday, December 10, 2012**.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Monday, December 10, 2012.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller at Wendy.Muller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

The drafting team will consider all comments and determine whether to make changes to the interpretation response prior to posting the interpretation for a 45-day comment period and initial ballot.

Background

In May 2011, the Standards Committee appointed a standing CIP Interpretation Drafting Team (IDT) for the development of CIP Interpretations. A project team from the CIP IDT has reviewed Consumers Energy's request for interpretation and developed this interpretation pursuant to the NERC Guidelines for IDTs. Consumers Energy requested clarification on Section 4.1 of CIP-003-3 Requirement R2 as to if a registered entity can assign different CIP Senior Managers for different applicable functions it is registered for.

Additional information is available on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, at Wendy.Muller@nerc.net or at 404-446-2560.

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A. Introduction

1. Title: Cyber Security — Security Management Controls

2. Number: CIP-003-3

3. Purpose: Standard CIP-003-3 requires that Responsible Entities have minimum security management controls in place to protect Critical Cyber Assets. Standard CIP-003-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. Applicability:

4.1. Within the text of Standard CIP-003-3, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator.

4.1.2 Balancing Authority.

4.1.3 Interchange Authority.

4.1.4 Transmission Service Provider.

4.1.5 Transmission Owner.

4.1.6 Transmission Operator.

4.1.7 Generator Owner.

4.1.8 Generator Operator.

4.1.9 Load Serving Entity.

4.1.10 NERC.

4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-003-3:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets shall only be required to comply with CIP-003-3 Requirement R2.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:

R1.1. The cyber security policy addresses the requirements in Standards CIP-002-3 through CIP-009-3, including provision for emergency situations.

R1.2. The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.

R1.3. Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.

R2. Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity's implementation of, and adherence to, Standards CIP-002-3 through CIP-009-3.

R2.1. The senior manager shall be identified by name, title, and date of designation.

R2.2. Changes to the senior manager must be documented within thirty calendar days of the effective date.

R2.3. Where allowed by Standards CIP-002-3 through CIP-009-3, the senior manager may delegate authority for specific actions to a named delegate or delegates. These delegations shall be documented in the same manner as R2.1 and R2.2, and approved by the senior manager.

R2.4. The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.

R3. Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).

R3.1. Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).

R3.2. Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures.

R3.3. Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.

R4. Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.

R4.1. The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002-3, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.

R4.2. The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.

R4.3. The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.

R5. Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.

R5.1. The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.

R5.1.1. Personnel shall be identified by name, title, and the information for which they are responsible for authorizing access.

R5.1.2. The list of personnel responsible for authorizing access to protected information shall be verified at least annually.

R5.2. The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.

R5.3. The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.

R6. Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendor-related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.

C. Measures

M1. The Responsible Entity shall make available documentation of its cyber security policy as specified in Requirement R1. Additionally, the Responsible Entity shall demonstrate that the cyber security policy is available as specified in Requirement R1.2.

M2. The Responsible Entity shall make available documentation of the assignment of, and changes to, its leadership as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of the exceptions, as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation of its information protection program as specified in Requirement R4.

M5. The Responsible Entity shall make available its access control documentation as specified in Requirement R5.

M6. The Responsible Entity shall make available its change control and configuration management documentation as specified in Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Requirement R2 applies to all Responsible Entities, including Responsible Entities which have no Critical Cyber Assets. Modified the personnel identification information requirements in R5.1.1 to include name, title, and the information for which they are responsible for authorizing access (removed the business phone information). Changed compliance monitor to Compliance Enforcement Authority.	
3		Update version number from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	Update

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Note: A valid interpretation request is one that requests additional clarity about one or more requirements in approved NERC reliability standards, but does not request approval as to how to comply with one or more requirements.

When completed, email this form to:
laura.hussey@nerc.net
For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

Request for an Interpretation of a Reliability Standard	
Date submitted: June 9, 2011	
Contact information for person requesting the interpretation:	
Name: Jeanne M. Kurzynowski	
Organization: Consumers Energy Company	
Telephone: (517)788-1110	E-mail: jmkurzyn@cmsenergy.com
Identify the standard that needs clarification:	
Standard Number (include version number, e.g. PRC-001-1): CIP-003-3	
Standard Title: Cyber Security – Security Management Controls	
Identify specifically what requirement needs clarification:	
Requirement Number and Text of Requirement: R2. Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity's implementation of, and adherence to, Standards CIP-002-3 through CIP-009-3.	
Identify the nature of clarification that is requested: (Check as many as applicable)	
☐ Clarify the required performance ☐ Clarify the conditions under which the performance is required ☒ Clarify which functional entity is responsible for performing an action in a requirement ☐ Clarify the reliability outcome the requirement is intended to produce	
Please explain the clarification needed: Section 4.1 of CIP-003-3, "Applicability" specifies that a "Responsible Entity" shall mean…", and lists several functions. If one substitutes any of these functions for the term "Responsible Entity", it would appear that there could be a different Senior Manager for each function to which that entity is registered. With regard to CIP-003-3, R2 can a Registered Entity assign different CIP Senior Managers for different applicable	

functions for which it is registered? (If so, a Registered Entity could have more than one CIP senior manager, but each Responsible Entity would have a single CIP senior manager.)

Identify the material impact associated with this interpretation:

Identify the material impact to your organization or others, if known, caused by the lack of clarity or an incorrect interpretation of this standard.

An incorrect interpretation of the standard may impact an organization's CIP compliance structure.

Question

Consumers Energy Corporation seeks clarification on the meaning of CIP-003-3, Requirement R3 as it relates to designating a CIP Senior Manager.

In its response, the Interpretation Drafting Team will answer whether a Registered Entity may assign different CIP Senior Managers for different applicable functions for which it is registered.

Response

No, a Registered Entity cannot assign different CIP Senior Managers for different applicable functions for which it is registered.

Organizational Registration is a process defined in the NERC Rules of Procedure undertaken by NERC and Regional Entities to identify which entities are responsible for reliability functions within the Regional Entity's Region. Within the NERC Rules of Procedure a "Registered Entity" means an owner, operator, or user of the Bulk Power System, or the entity registered as its designee for the purpose of compliance, which is included in the NERC Compliance Registry.

The number of CIP Senior Managers depends on how the entity registers and appears in the NERC Compliance Registry. Each Registered Entity, even if registered as performing multiple registration functions, shall assign a single CIP Senior Manager. If the same single company has only one NERC ID, i.e. the entity is registered once for its GO/GOP and TO/TOP collectively, the entity assigns one CIP Senior Manager. If a single company has multiple Registered Entities (i.e. company has registered one business segment as a GO/GOP, and another business segment registered as TO/TOP) it could assign a different CIP Senior Manager to each Registered Entity, but that would not preclude the entity from assigning a single CIP Senior Manager to both Registered Entities.

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Note: A valid interpretation request is one that requests additional clarity about one or more requirements in approved NERC reliability standards, but does not request approval as to how to comply with one or more requirements.

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Organization: Consumers Energy Company	
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Identify the standard that needs clarification:	
Standard Number (include version number, e.g. PRC-001-1): CIP-003-3	
Standard Title: Cyber Security – Security Management Controls	
Identify specifically what requirement needs clarification:	
Requirement Number and Text of Requirement: R2. Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity's implementation of, and adherence to, Standards CIP-002-3 through CIP-009-3.	
Identify the nature of clarification that is requested: (Check as many as applicable)	
☐ Clarify the required performance ☐ Clarify the conditions under which the performance is required ☒ Clarify which functional entity is responsible for performing an action in a requirement ☐ Clarify the reliability outcome the requirement is intended to produce Please explain the clarification needed: Section 4.1 of CIP-003-3, "Applicability" specifies that a "Responsible Entity" shall mean…", and lists several functions. If one substitutes any of these functions for the term "Responsible Entity", it would appear that there could be a different Senior Manager for each function to which that entity is registered. With regard to CIP-003-3, R2 can a Registered Entity assign different CIP Senior Managers for different applicable	

functions for which it is registered? (If so, a Registered Entity could have more than one CIP senior manager, but each Responsible Entity would have a single CIP senior manager.)
Identify the material impact associated with this interpretation:
Identify the material impact to your organization or others, if known, caused by the lack of clarity or an incorrect interpretation of this standard. An incorrect interpretation of the standard may impact an organization's CIP compliance structure.

A. Introduction

1. Title: Cyber Security — Systems Security Management

2. Number: CIP-007-3

3. Purpose: Standard CIP-007-3 requires Responsible Entities to define methods, processes, and procedures for securing those systems determined to be Critical Cyber Assets, as well as the other (non-critical) Cyber Assets within the Electronic Security Perimeter(s). Standard CIP-007-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. Applicability:

4.1. Within the text of Standard CIP-007-3, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator.

4.1.2 Balancing Authority.

4.1.3 Interchange Authority.

4.1.4 Transmission Service Provider.

4.1.5 Transmission Owner.

4.1.6 Transmission Operator.

4.1.7 Generator Owner.

4.1.8 Generator Operator.

4.1.9 Load Serving Entity.

4.1.10 NERC.

4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-007-3:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007-3, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.

R1.1. The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.

R1.2. The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.

R1.3. The Responsible Entity shall document test results.

R2. Ports and Services — The Responsible Entity shall establish, document and implement a process to ensure that only those ports and services required for normal and emergency operations are enabled.

R2.1. The Responsible Entity shall enable only those ports and services required for normal and emergency operations.

R2.2. The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).

R2.3. In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.

R3. Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003-3 Requirement R6, shall establish, document and implement a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).

R3.1. The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the patches or upgrades.

R3.2. The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.

R4. Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software ("malware") prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic Security Perimeter(s).

R4.1. The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.

R4.2. The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention "signatures." The process must address testing and installing the signatures.

R5. Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.

R5.1. The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to know" with respect to work functions performed.

R5.1.1. The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-3 Requirement R5.

R5.1.2. The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.

R5.1.3. The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-3 Requirement R5 and Standard CIP-004-3 Requirement R4.

R5.2. The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.

R5.2.1. The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.

R5.2.2. The Responsible Entity shall identify those individuals with access to shared accounts.

R5.2.3. Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).

R5.3. At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:

R5.3.1. Each password shall be a minimum of six characters.

R5.3.2. Each password shall consist of a combination of alpha, numeric, and "special" characters.

R5.3.3. Each password shall be changed at least annually, or more frequently based on risk.

R6. Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible, implement automated tools or organizational process controls to monitor system events that are related to cyber security.

R6.1. The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.

R6.2. The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.

R6.3. The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008-3.

R6.4. The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.

R6.5. The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.

R7. Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-3.

R7.1. Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.

R7.2. Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.

R7.3. The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.

R8. Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:

R8.1. A document identifying the vulnerability assessment process;

R8.2. A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;

R8.3. A review of controls for default accounts; and,

R8.4. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.

R9. Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007-3 at least annually. Changes resulting from modifications to the systems or controls shall be documented within thirty calendar days of the change being completed.

C. Measures

M1. The Responsible Entity shall make available documentation of its security test procedures as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation and records of its security patch management program, as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation and records of its malicious software prevention program as specified in Requirement R4.

M5. The Responsible Entity shall make available documentation and records of its account management program as specified in Requirement R5.

M6. The Responsible Entity shall make available documentation and records of its security status monitoring program as specified in Requirement R6.

M7. The Responsible Entity shall make available documentation and records of its program for the disposal or redeployment of Cyber Assets as specified in Requirement R7.

M8. The Responsible Entity shall make available documentation and records of its annual vulnerability assessment of all Cyber Assets within the Electronic Security Perimeters(s) as specified in Requirement R8.

M9. The Responsible Entity shall make available documentation and records demonstrating the review and update as specified in Requirement R9.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Responsible Entity shall retain security–related system event logs for ninety calendar days, unless longer retention is required pursuant to Standard CIP-008-3 Requirement R2.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment and acceptance of risk. Revised the Purpose of this standard to clarify that Standard CIP-007-2 requires Responsible Entities to define methods, processes, and procedures for securing Cyber Assets and other (non-Critical)	

		Assets within an Electronic Security Perimeter. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. R9 changed ninety (90) days to thirty (30) days Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version numbers from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	

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maureen.long@nerc.net
For questions about this form or for assistance in completing the form, call Maureen Long at 813-468-5998.

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard

Date submitted: 12-28-2011

Contact information for person requesting the interpretation:

Name:	Charles Lewis
Organization:	ITC Transmission
Telephone:	248-946-3182
E-mail:	clewis@itctransco.com

Identify the standard that needs clarification:

Standard Number (include version number): CIP-007-3

(example: PRC-001-1)

Standard Title: Cyber Security – Systems Security Management

Identify specifically what requirement needs clarification:

Requirement Number and Text of Requirement:

R5. Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.

R5.3. At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:
R5.3.1. Each password shall be a minimum of six characters.
R5.3.2. Each password shall consist of a combination of alpha, numeric, and “special” characters.
R5.3.3. Each password shall be changed at least annually, or more frequently based on risk.

Clarification needed:

ITC respectfully requests an interpretation regarding the following:

1. Does each sub-requirement, including R5.3, of R5 require that both "technical and procedural controls" be utilized?

2. Do "technical controls", utilized in the context of R5.3, mean that each individual cyber asset device within an ESP has to automatically enforce each of the three R5.3 sub-requirements? The three bullets below are part of this question; they are examples if this is interpreted to be true.

- R5.3.1. Each password shall be a minimum of six characters. Each individual cyber asset device within an ESP has to automatically reject any password that does not conform to a minimum of six characters.
- R5.3.2. Each password shall consist of a combination of alpha, numeric, and "special" characters. Each individual cyber asset device within an ESP has to automatically reject any password that does not conform to a combination of alpha, numeric and "special" characters.
- R5.3.3. Each password shall be changed at least annually, or more frequently based on risk. Each individual cyber asset device within an ESP has to automatically force passwords to be changed at least annually or at a specified interval based on risk.

Identify the material impact associated with this interpretation:

Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard.

If it is interpreted that R5.3 requires "technical controls" that automatically enforce password requirements, then there will be a need for entities to file a significant number of additional TFEs. The majority of devices used in the industry, while allowing passwords that meet all of the R5.3 sub-requirements, are not able to automatically enforce the requirements of R5.3.1, R5.3.2 and R5.3.3. In addition, it is expected the TFEs submitted for this requirement will have to be kept in place for a long period of time until device manufacturers create products that can enforce R5.3.1, R5.3.2 and R5.3.3.

A correct interpretation is needed for entities to determine whether existing cyber assets within ESPs are fully compliant with this requirement to avoid penalties associated with noncompliance.

Question

ITC Transmission seeks clarification on the meaning of CIP-007-3, Requirement R5 as it relates to both technical and procedural controls.

In its response, the Interpretation Drafting Team will answer:

1. Whether each sub-requirement of R5 requires both "technical and procedural controls."
2. Whether technical controls in Requirement R5.3 mean that each individual Cyber Asset within the Electronic Security Perimeter (ESP) has to automatically enforce each of the three R5.3 sub-requirements.

Response

Question 1: Does each sub-requirement of Requirement R5 require use of <u>both</u> "technical and procedural controls"?

No, it is not necessary for both technical and procedural controls to be used in each sub-requirement of Requirement R5. The use of "and" in Requirement R5 indicates that the responsible entity must implement both technical and procedural controls to achieve collectively the sub-requirements within Requirement R5 and the associated sub-requirements. Both are not necessary for each sub-requirement individually. Generally, technical controls are carried out or managed by computer systems. That is distinct from a technical aspect that enables or confirms procedural enforcement. While it is possible to have a technical component, tool, or aspect for each procedural control, mere use of technology to enable or support a procedural control is not necessarily a technical control itself. If a control relies on ongoing human intervention, then it is generally a procedural control. Procedural controls are the actions that people take, and they are the process of developing and ensuring compliance with policy and procedures. The responsible entity must look at what's performing the control to determine whether it's technical or procedural: the control is accomplished either by a human being using technology (procedural) or a computer managing or performing the control (technical). The IDT also notes that regardless of control type (technical or procedural) the entity has the compliance requirement of implementing the control and demonstrating evidence of the control.

Question 2: Does the use of "technical controls" in Requirement R5.3 mean that each individual Cyber Asset within the Electronic Security Perimeter (ESP) has to automatically enforce each of the three R5.3 sub-requirements.

No, the IDT interprets the three sub-requirements within R5.3 no differently than the other sub-requirements of R5, with the exception of the technical feasibility exception (TFE) capability provided under R5.3. As requested under the request for interpretation, the concept of automatically enforcing controls is viewed by the IDT as the need to enforce the combination of the technical and procedural controls that are implemented to achieve strict compliance. The automatic enforcement component would apply to the technical controls that are implemented, however most procedural controls are not automatic. The IDT interprets that the responsible entity would need to demonstrate that controls have been put in place to achieve strict compliance with the three sub-requirements of R5.3. In the case where a specific device is not capable of implementing either a technical or procedural control, the entity would file for TFE treatment.

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Identify specifically what requirement needs clarification:

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R5.3.3. Each password shall be changed at least annually, or more frequently based on risk.

Clarification needed:

ITC respectfully requests an interpretation regarding the following:

1. Does each sub-requirement, including R5.3, of R5 require that both "technical and procedural controls" be utilized?

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A correct interpretation is needed for entities to determine whether existing cyber assets within ESPs are fully compliant with this requirement to avoid penalties associated with noncompliance.

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Standards Announcement

Project 2012-INT-04 – Interpretation of CIP-007-3 for ITC

Formal Comment Period Open: November 9, 2012 – December 10, 2012

Now Available

A formal comment period for the interpretation of **CIP-007-3** for ITC is open through **8 p.m. Eastern on Monday, December 10, 2012**.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Monday, December 10, 2012.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller at Wendy.Muller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

The drafting team will consider all comments and determine whether to make changes to the interpretation response prior to posting the interpretation for a 45-day comment period and initial ballot.

Background

In May 2011, the Standards Committee appointed a standing CIP Interpretation Drafting Team (IDT) for the development of CIP Interpretations. A project team from the CIP IDT has reviewed ITC's request for interpretation and developed this interpretation pursuant to the NERC Guidelines for IDTs. In its first question, ITC asked for clarification on whether each sub-requirement of CIP-007-3, Requirement R5 requires both "technical and procedural controls." In its second question, ITC asked for clarification on whether technical controls in CIP-007-3, Requirement R5.3 mean that each individual Cyber Asset within the Electronic Security Perimeter (ESP) has to automatically enforce each of the three R5.3 sub-parts.

Additional information is available on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, at Wendy.Muller@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2007-02 Operating Personnel Communications Protocols

Formal Comment Period Now Open: **November 14, 2012 – December 13, 2012**

RSAW Posted for Industry Comments: **November 14, 2012 – December 13, 2012**

Upcoming:
Successive Ballot and Non-binding Poll: December 4 – December 13, 2012

Now Available

A formal comment period for **COM-003-1 – Operating Personnel Communication Protocols** is open through **8 p.m. Eastern on Thursday, December 13, 2012.**

A successive ballot of COM-003-1 and a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted **Tuesday, December 4, 2012 through 8 p.m. Eastern on Thursday, December 13, 2012.**

In response to comments received during the last comment period and other input, the drafting team has adopted many of the recommendations of commenters and incorporated them into draft 4 of COM-003-1, as summarized below:

- Combined Requirements R1 and R3, and R2 and R4 to emulate CIP version 5. The language calls for an applicable entity to "implement documented communication protocols in a manner that identifies, assesses and corrects deficiencies……."
- Added additional language to clarify the definition of "Operating Instructions," as commenters expressed concerns over the scope of the term.
- Clarified that R1 and R2 now apply to Operating Instructions between Functional Entities.

This version was drafted in conjunction with the development of the Reliability Standard Audit Worksheet (RSAW). Changes were made to the RSAW to reflect the changes in draft 4 of COM-003-1 and changes suggested by some commenters. The RSAW is posted for an informal comment period along with COM-003-1.

Instructions for Commenting

A formal comment period on the draft standard is open through **8 p.m. Eastern on Thursday, December 13, 2012**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller at wendy.muller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

A comment period on the draft RSAW is open through **8 p.m. Eastern on Thursday, December 13, 2012**. The draft RSAW is posted on the NERC Compliance Reliability Standard Audit Worksheet page. Please submit comments on the draft RSAW by using the RSAW feedback form on the project page and sending to: RSAWfeedback@nerc.net.

Next Steps

A second successive ballot of COM-003-1 and a non-binding poll of the associated VRFs and VSLs will be conducted beginning on **Tuesday, December 4, 2012 through 8 p.m. Eastern on Thursday, December 13, 2012**.

Background

The purpose of this project is to require that real-time system operators use standardized communication protocols during normal and emergency operations to enhance the clarity of communications, improve situational awareness, shorten response time and ultimately serve reliability. As requested in the SAR, in the development of this proposed standard, the drafting team reviewed communication protocols in other NERC standards and considered the use of alert level guidelines and three-part communications to achieve consistency across regions. The proposed standard is designed to ensure that reliability-related information is conveyed effectively, accurately, consistently and in a timely manner to ensure mutual understanding by all key parties, both during alerts and emergencies and during the communication of routine operating instructions.

There are two projects that include the modification of the COM family of standards in the scope of their SAR. This project, Project 2007-02 – Operating Personnel Communications Protocols, is concerned with communication protocols for normal and emergency operations. The other project, Project 2006-06 – Reliability Coordination, is concerned with ensuring that the reliability-related requirements applicable to the Reliability Coordinator are clear, measurable, unique, enforceable, and sufficient to maintain reliability of the Bulk Electric System.

The Project 2006-06 Reliability Coordination drafting team (RC SDT) has limited the scope of its modifications to those that address communication during emergency operations. The RC SDT has developed a new term, “Reliability Directive,” to specifically address those communications, and this term has been approved by the ballot pool. The proposed definition of Reliability Directive is “A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impact.” The

RC SDT is proposing to require three-part communication for Reliability Directives, with a High Violation Risk Factor for those requirements.

Since Project 2007-02 – Operating Personnel Communications Protocols addresses communication protocols for normal *and* emergency operations, the drafting team has proposed a new term, "Operating Instruction," to define the scope of communications to which the COM-003-1 protocols would apply. The proposed definition of Operating Instruction is:

"*Operating Instruction —A command by a System Operator of a Reliability Coordinator, or of a Transmission Operator, or of a Balancing Authority, where the recipient of the command is expected to act, to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. Discussions of general information and of potential options or alternatives to resolve BES operating concerns are not commands and are not considered Operating Instructions.*"

The two standards complement each other. COM-003 establishes the practice of using communication protocols for all Operating Instructions, and provides for an entity to identify, assess and correct any deficiencies with that practice. COM-002 is focused on communications during emergency situations.

Additional information is available on the project page.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller, Standards Process Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. The Standards Committee (SC) approved the Standard Authorization Request (SAR) for posting on March 1, 2007.
2. The SAR was posted for comment from March 19 through April 17, 2007.
3. The SC sought SAR drafting team nominations April 18 through May 2, 2007.
4. The SAR drafting team posted reply comments to industry comments received on the first posting SAR on June 8, 2007
5. Standard drafting team appointed by SC Executive Committee on June 28, 2007
6. Version 1 draft of Standard posted November 2009 for Informal Comments closed January 15 2010.
7. Version 2 draft of Standard posted May 2012 for Formal Comments, Initial Ballot closed June 20 2012.
8. Version 3 draft of Standard posted August 2012 for Formal Comments, Initial Ballot closed September 20 2012.

~~7.~~

Description of Current Draft:

This is the ~~third~~ fourth draft of a new standard requiring the use of standardized communication protocols during normal and emergency operations to improve situational awareness and shorten response time. The drafting team requests posting for a 30-day concurrent Formal Comment period and Ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~1. Drafting team considers comments, makes conforming changes, and requests SC approval to proceed to pre-ballot comment period.~~	~~July 2012~~
~~2. Second Ballot of Standards.~~	~~August 2012~~
~~3. Successive Ballot of Standards~~	~~September 2012~~
1. Second Successive Ballot of Standards	~~October~~ November 2012

~~4.~~2.Recirculation ballot of standards.	January ~~October~~ ~~2012~~ 2013
~~5.~~3.Board adopts standards.	~~November~~ February ~~2012~~ 2013

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

When using terms or phrases contained in the Reliability Standards Glossary of Terms for communications it should be cited as the source. When used in written communications, terms or phrases contained in the Reliability Standards Glossary of Terms are capitalized.

Operating Instruction —A ~~C~~command ~~from~~ by a System Operator of a Reliability Coordinator, or of a Transmission Operator, or of a Balancing Authority, where the recipient of the command is expected to act, to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. Discussions of general information and of potential options or alternatives to resolve BES operating concerns are not commands and are not considered Operating Instructions.

A. Introduction

1. **Title:** Operating Personnel Communications Protocols

2. **Number:** COM-003-1

3. **Purpose:** To provide System Operators uniform communications protocols that reduce the possibility of miscommunication that could lead to action or inaction harmful to the reliability of BES.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1 Balancing Authority

   4.1.2 Distribution Provider

   4.1.3 Generator Operator

   4.1.4 Reliability Coordinator

   4.1.5 Transmission Operator

5. **(Proposed) Effective Date:** First day of first calendar quarter, twelve (12) calendar months following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustee adoption.

6. **Background:**

The SDT has incorporated within this standard a recognition that these requirements should not focus on individual instances of failure as a ~~sole~~ basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on whether there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying "implement" as follows:

> Each … shall implement, in a manner that identifies, assesses, and corrects deficiencies, . . .

The term *documented communication protocols* refers to a set of required protocols specific to the Functional Entity. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented protocols, but they must address all of the applicable parts of the Requirement. The documented protocols themselves are not required to include the ". . . identifies, assesses, and corrects deficiencies, . . ." elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented protocols and could be accomplished through other controls or compliance management activities.

~~5.~~

B. Requirements

R1. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall implement, in a manner that identifies, assesses and corrects deficiencies, ~~have~~ documented communication protocols for Operating Instructions between ~~f~~Functional ~~e~~Entities ~~that incorporate~~ include the following: [*Violation Risk Factor: Medium ~~Low~~*] [*Time Horizon: Long-term Planning*]

1.1. Use of the English language when issuing or responding to an oral or written Operating Instruction ~~between functional entities~~, unless another language is mandated by law or regulation. ~~Transmission Operators and Balancing Authorities may use an alternate language for internal operations.~~

1.2. Use of the 24-hour clock format when referring to clock times when issuing an oral or written Operating Instruction.

1.3. Use of the time, the time zone where the action will occur and indication of whether the time is daylight saving time or standard time w~~W~~hen issuing an oral or written Operating Instruction that refers to clock times between ~~functional~~ Functional ~~entities~~ Entities in different time zones~~, when referring to clock times include the time, the time zone where the action will occur and indicate whether the time is daylight saving time or standard time~~.

1.4. Use of the name specified by the owner(s) for each Transmission interface Element or Transmission interface Facility w~~W~~hen referring to a Transmission interface Element or a Transmission interface Facility~~(when issuing)~~ in an oral or written Operating Instruction ~~between functional entities, use the name specified by the owner(s) for that Transmission interface Element or Transmission interface Facility~~, unless another name is mutually agreed to by the F~~f~~unctional E~~e~~ntities.

1.5. Use of alpha-numeric clarifiers when issuing an oral Operating Instruction for Facilities and Elements in instances where the nomenclature of Facilities or Elements is in alpha-numeric format (~~e.g.~~ ~~(~~for example~~)~~ if an entity designated a circuit breaker "One two~~(12)~~Bravo" (12B). ~~o~~One two Bravo would need alpha-numeric clarifiers if used in an oral Operating Instruction)

1.6. When issuing an oral two party, person-to-person Operating Instruction, require the issuer to:

- Confirm that the response from the recipient of the Operating Instruction was accurate, or
- Reissue the Operating Instruction to resolve a misunderstanding.

1.7. When receiving an oral two party, person-to-person Operating Instruction, require the recipient to repeat, restate, rephrase, or recapitulate the Operating Instruction.

1.8. When issuing an oral Operating Instruction through a one-way burst messaging system used to communicate a common message to multiple parties in a short time

period (e.g. (for example) an all call system), verbally or electronically confirm receipt from one or more receiving parties.

1.9. When receiving an oral Operating Instruction through a one-way burst messaging system used to communicate a common message to multiple parties in a short time period (e.g. (for example) an all call system), request clarification from the initiator if the communication is not understood.

R2. Each Distribution Provider and Generator Operator shall implement, in a manner that identifies, assesses and corrects deficiencies, have documented communication protocols for Operating Instructions, between fFunctional eEntities ,that incorporate include the following: [*Violation Risk Factor: Low Medium*] [*Time Horizon: Long-term Planning*]

2.1. When receiving an oral two party, person-to-person Operating Instruction, require the recipient to repeat, restate, rephrase, or recapitulate the Operating Instruction.

2.2. When receiving an oral Operating Instruction through a one-way burst messaging system used to communicate a common message to multiple parties in a short time period (e.g. an all call system), request clarification from the initiator if the communication is not understood.

R3. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall implement a process for identifying deficiencies with adherence to the documented communication protocols specified in Requirement R1 that: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

3.1. Identifies potential deficiencies,

3.2. Assesses the deficiencies found,

3.3. Corrects the deficiencies, and

3.4. Evaluates the process based on deficiencies found external to Part 3.1 and either

- implements modifications to the process when the evaluation determines that modification of the process is necessary to address the deficiencies found; or
- demonstrates that no modification to the process is necessary to address the deficiencies.

R4. Each Distribution Provider and Generator Operator shall implement a process for identifying deficiencies with adherence to the documented communication protocols specified in Requirement R2 that: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

4.1. Identifies potential deficiencies,

4.2. Assesses the deficiencies found,

4.3. Corrects the deficiencies, and

4.4. Evaluates the process based on deficiencies found external to Part 4.1 and either

- ~~implements modifications to the process when the evaluation determines that modification of the process is necessary to address the deficiencies found; or~~
- ~~demonstrates that no modification to the process is necessary to address the deficiencies.~~

C. Measures

M1. Evidence must include each applicable entity's documented communications protocols developed for Requirement R1 and must demonstrat~~ing~~e that the protocols have been implemented in a manner that identifies, assesses and corrects deficiencies. ~~Each Balancing Authority, Reliability Coordinator, and Transmission Operator, shall provide its documented communications protocols developed for Requirement R1~~.

~~**M1.**~~**M2.** Evidence must include each applicable entity's documented communications protocols developed for Requirement R2 and must demonstrate that the protocols have been implemented in a manner that identifies, assesses and corrects deficiencies.

~~**M2.** demonstrating~~ ~~Each Distribution Provider and Generator Operator , shall provide its documented communications protocols developed for Requirement R2.~~

~~**M3.** Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall provide the results of its process developed for Requirement R3.~~

~~**M4.** Each Distribution Provider and Generator Operator shall provide the results of its process developed for Requirement R4.~~

~~**M5.**~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Transmission Operator, Balancing Authority, Reliability Coordinator, Generator Operator, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement

Authority to retain specific evidence for a longer period of time as part of an investigation:

Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall retain evidence of its manner that identifies, assesses and corrects deficiencies for Requirement ~~R3~~ R1 Measure ~~M3~~ M1 for the most recent 90 days.

Each Distribution Provider and Generator Operator shall retain evidence of its manner that identifies, assesses and corrects deficiencies for~~for~~ Requirement ~~R4~~ R2 Measure ~~M4~~ M2 for the most recent 90 days.

If a Transmission Operator, Balancing Authority, Reliability Coordinator, Generator Operator or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Additional Compliance Information

None

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long Term Planning	~~Low~~Medium	The ~~responsible~~ Responsible ~~entity~~ Entity did not include one (1) of the nine (9) parts of Requirement R1, Parts 1.1 to 1.9 in their documented communication protocols	The Responsible Entity ~~responsible entity~~ did not include two (2) of the nine (9) parts of Requirement R1, Parts 1.1 to 1.9 in their documented communication protocols	The Responsible Entity ~~responsible entity~~ did not include three (3) of the nine (9) parts of Requirement R1, Parts 1.1 to 1.9 in their documented communication protocols	The Responsible Entity ~~responsible entity~~ did not include four (4) or more of the nine (9) parts of Requirement R1, Parts 1.1 to 1.9 in their documented communication protocols OR The Responsible Entity ~~responsible entity~~ did not have documented communication protocols as required in Requirement R1 OR The Responsible Entity did not implement, in a manner that identifies, assesses and corrects deficiencies, their documented communication protocols as required in Requirement R1

R2	Long Term Planning	~~Low~~Medium	N/A	N/A	The Responsible Entity ~~responsible entity~~ did not include one (1) of the two (2) parts of Requirement R2, Parts 2.1 to 2.2 in their documented communication protocols	The Responsible Entity ~~responsible entity~~ did not include Parts 2.1 to 2.~~3~~ 2 ~~(3)~~ of Requirement R2, in their documented communication protocols OR The responsible entity did not have documented communication protocols as required in Requirement R2 OR The Responsible Entity did not implement, in a manner that identifies, assesses and corrects deficiencies, their documented communication protocols as required in Requirement R2

~~R3~~	~~Operations Planning~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Responsible Entity does not have a process for identifying deficiencies with adherence to the documented communication protocols specified in Requirement R1;~~ ~~Or~~ ~~The Responsible Entity did not evaluate their process based on deficiencies found external to Part 3.1 to determine whether modification of the process is necessary;~~ ~~Or~~ ~~The Responsible Entity did not implement modifications to the process when the evaluation determined that modification of the process was necessary to address the deficiencies found;~~ ~~Or~~ ~~The Responsible Entity did not demonstrate that no modification to the process was necessary to address the deficiencies found external to Part 3.1.~~

~~R4~~	~~Operations Planning~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Responsible Entity does not have a process for identifying deficiencies with adherence to the documented communication protocols specified in Requirement R2;~~ ~~Or~~ ~~The Responsible Entity did not evaluate their process based on deficiencies found external to Part 4.1 to determine whether modification of the process is necessary;~~ ~~Or~~ ~~The Responsible Entity did not implement modifications to the process when the evaluation determined that modification of the process was necessary to address the deficiencies found;~~ ~~Or~~ ~~The Responsible Entity did not demonstrate that no modification to the process was necessary to address the deficiencies found external to Part 4.1.~~

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-02 - Operating Personnel Communications Protocols

Implementation Plan for COM-003-1 – Operating Personnel Communications Protocols Standard

Approvals Required

COM-003-1 – Operating Personnel Communications Protocols Standard

Prerequisite Approvals

None

Revisions to Glossary

The following term is proposed for addition to the NERC Glossary of Terms:

Operating Instruction —

Operating Instruction —A command by a System Operator of a Reliability Coordinator, or of a Transmission Operator, or of a Balancing Authority, where the recipient of the command is expected to act to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. Discussions of general information and of potential options or alternatives to resolve BES operating concerns are not commands and are not considered Operating Instructions.

~~Command from a System Operator to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System.~~

Applicable Entities

Balancing Authority
Distribution Provider
Generator Operator
Reliability Coordinator
Transmission Operator

Revisions or Retirements to Approved Standards

Approved Requirement to be Retired	Proposed Replacement Requirement(s)
COM-001-1.1 Requirement R4 R4.Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and	COM-003-1 Requirement R1 Part 1.1 **R1.** Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall implement, in a manner that identifies, assesses and corrects

among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations	deficiencies, documented communication protocols for Operating Instructions between Functional Entities that include the following: [*Violation Risk Factor: ~~Low~~ Medium*] [*Time Horizon: Long-term Planning*] ~~R1. Each Balancing Authority, , Reliability Coordinator, and Transmission Operator shall have documented communications protocols for Operating Instructions that incorporate the following:~~ 1.1. Use of the English language when issuing an oral or written Operating Instruction between functional entities, unless another language is mandated by law or regulation. ~~Transmission Operators and Balancing Authorities may use an alternate language for internal operations.~~

Conforming Changes to Other Standards

None

Effective Dates

COM-003-1 shall become effective the first day of first calendar quarter, twelve calendar months following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve calendar months from the date of Board of Trustee adoption.

COM-001-1.1 Requirement R4 shall expire midnight of the day immediately prior to the Effective Date of COM-001-2 in the particular Jurisdiction in which COM-001-2 is becoming effective.

Project 2007-~~02~~ 02: Operating Personnel Communication Protocols

Mapping Document

1. **Mapping Document Showing Translation of COM-001-1, R4– Telecommunications into COM-003-1–Operating Personnel Communications Protocol**

Requirement in Approved Standard	Translation to New Standard or Other Action	Comments
R4.Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations	Moved into COM 003-1 R1.1	R1 Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall implement, in a manner that identifies, assesses and corrects deficiencies, documented communication protocols for Operating Instructions between Functional Entities that include the following:~~Each Balancing Authority, Distribution Provider, Generator Operator, Reliability Coordinator, and Transmission Operator shall have documented communications protocols that incorporate the following~~: 1.1. Use of the English language when issuing an oral or written Operating Instruction between functional entities, unless another language is mandated by law or regulation.

Requirement in Approved Standard	Translation to New Standard or Other Action	Comments
		~~Transmission Operators and Balancing Authorities may use an alternate language for internal operations~~.

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Project 2007-02, COM-003-1 Operating Personnel Communication Protocols Rationale and Technical Justification

Justification for Requirements in Draft 4

Rationale and Technical Justification

The Quality Review team for the draft 2 posting of COM-003-1 highly recommended that the OPCPSDT provide a justification or rationale document to aid reviewers in their examination of this draft of COM-003-1. The OPCPSDT agrees with the QR recommendation and has developed the following to support the standard and to help stakeholders understand the intent and scope of the standard. This version of the standard features a non traditional approach to standards that could alleviate concerns that surfaced in comments in drafts one, two and three.

Requirement R1

Requirement R1 requires entities that can both issue and receive Operating Instructions to implement documented communication protocols in a manner that identifies, assesses, and corrects deficiencies. Because Operating Instructions affect Facilities and Elements of the Bulk Electric System, the communication of those Operating Instructions must be understood by all involved parties, especially when those communications occur between functional entities. An EPRI study reviewed nearly 400 switching mishaps by electric utilities and found that roughly 19% of errors (generally classified as loss of load, breach of safety, or equipment damage) were due to communication failures.[1] This was nearly identical to another study of dispatchers from 18 utilities representing nearly 2000 years of operating experience that found that 18% of the operators' errors were due to communication problems. [2]The necessary protocols include the use of the

[1] Beare, A., Taylor, J. *Field Operation Power Switching Safety*, WO2944-10, Electric Power Research Institute.

[2] Bilke, T., *Cause and prevention of human error in electric utility operations*, Colorado State University, 1998.

English language (from COM-001-1.1 R4), time formatting, mutually agreed nomenclature for Transmission interface Elements, alpha-numeric clarifiers, and three part communications.

Requirement R2

Requirement R2 requires entities that only receive Operating Instructions to implement documented communication protocols in a manner that identifies, assesses, and corrects deficiencies .
The two protocols (R2 , Parts 2.1 and 2.2) required are repeat back for three part communication and clarification if an "all call" communication is unclear.

Rationale

The SDT has incorporated within this standard a recognition that these requirements should not focus on individual instances of failure as a basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on whether there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying "implement" as follows:

Each … shall implement, in a manner that identifies, assesses, and corrects deficiencies, . . .

The term *documented communication protocols* refers to a set of required protocols specific to the Functional Entity and the Functional Entities they must communicate with. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented protocols, but they must address all of the applicable parts of the Requirement. The documented protocols themselves are not required to include the ". . . identifies, assesses, and corrects deficiencies, . . ." elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented protocols and could be accomplished through other controls or compliance management activities.

Project 2007-2 – Operating Personnel Communications Protocol

VRF and VSL Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in COM 003-1 Operating Personnel Communications Protocols.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Operations Personnel Communications Protocol Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a

cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for COM-003-1:

There are ~~three~~ two requirements in COM-003-1, draft ~~4~~1. Requirements R1~~,~~ and R2 are assigned a "Medium" VRF~~,~~. ~~and R3 were assigned a "Medium" VRF.~~

The elimination of draft 3 R3 and R4 and the language change to R1 and R2 which now reads:"*Each ….. shall implement, in a manner that identifies, assesses and corrects deficiencies, documented communication protocols for Operating Instructions between Functional Entities that include the following:* " ~~may~~ warrants raising the VRF to "Medium" because it makes the requirement more than just administrative as it now features an evaluative process that would have a deeper impact on the reliability of the BES.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

The drafting team will complete the following table, providing of analysis and justification for each VRF and VSL, for each requirement.

VRF and VSL Justifications – COM 003-1, R1	
Proposed VRF	~~Low~~Medium
NERC VRF Discussion	R1 is a requirement in a planning time frame that, if violated, ~~would not~~could, under ~~the~~ emergency, abnormal, or restorative conditions anticipated by the preparations, ~~be expected to~~ directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. The VRF for this requirement is "Medium~~Low~~" which is consistent with NERC guidelines
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report:** R1 falls under Recommendation 24 of the Blackout Report. The VRF for this requirement is "Medium~~Low~~" which is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard :** The requirement has sub-requirements that are of equal importance and similarly address communication protocols; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards:** This requirement calls for the ~~establishment~~ implementation of documented communication protocols that reduce the possibility of miscommunication which could eventually lead to action or inaction harmful to the reliability of BES.

VRF and VSL Justifications – COM 003-1, R1			
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs:** Failure to utilize communication protocols properly could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of the requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is " Medium ~~Low~~" which is consistent with NERC guidelines		
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:** COM-003-1, Requirement R1 contains only one objective which is to specify clear, formal and universally applied communication protocols that reduce the possibility of miscommunication which could lead to action or inaction harmful to the reliability of BES. Since the requirement has only one objective, only one VRF was assigned.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity did not include one (1) of the nine (9) parts of Requirement R1, Parts 1.1 to 1.9 in their documented communication protocols ~~The responsible entity did not include one (1) of the nine (9) parts of Requirement R1, Parts 1.1 to 1.9 in their documented communication protocols~~	The Responsible Entity did not include two (2) of the nine (9) parts of Requirement R1, Parts 1.1 to 1.9 in their documented communication protocols~~The responsible entity did not include two (2) of the nine (9) parts of Requirement R1, Parts 1.1 to 1.9 in their documented communication protocols~~	The Responsible Entity did not include three (3) of the nine (9) parts of Requirement R1, Parts 1.1 to 1.9 in their documented communication protocols ~~The responsible entity did not include three (3) of the nine (9) parts of Requirement R1, Parts 1.1 to 1.9 in their documented~~	The Responsible Entity ~~responsible entity~~ did not include four (4) or more of the nine (9) parts of Requirement R1, Parts 1.1 to 1.9 in their documented communication protocols OR The Responsible Entity ~~responsible entity~~ did not have documented

VRF and VSL Justifications – COM 003-1, R1			
		~~communication protocols~~	communication protocols as required in Requirement R1. OR The Responsible Entity did not implement, in a manner that identifies, assesses and corrects deficiencies, their documented communication protocols as required in Requirement R1

VRF and VSL Justifications – COM 003-1, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Based on the VSL Guidance, the SDT developed four VSLs based on misapplication or absence of common communication protocols. If no communication protocols are used at all or if the number of required protocols falls below the listed thresholds, then the VSL is Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement

VRF and VSL Justifications – COM 003-1, R1	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – COM 003-1, R2	
Proposed VRF	~~Low~~Medium
NERC VRF Discussion	R2 is a requirement in a planning time frame that, if violated, ~~would not~~could, under ~~the~~ emergency, abnormal, or restorative conditions anticipated by the preparations, ~~be expected to~~directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. The VRF for this requirement is "Medium~~Low~~" which is consistent with NERC guidelines
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report:** R2 falls under Recommendation 24 of the Blackout Report. The VRF for this requirement is "Medium~~Low~~" which is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard :** The requirement has sub-requirements that are of equal importance and similarly address communication protocols; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards:** This requirement calls for the ~~establishment~~ implementation of documented communication protocols that reduce the possibility of miscommunication which could eventually lead to action or inaction harmful to the reliability of BES.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs:** Failure to utilize communication protocols properly could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of the requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Medium~~Low~~" which is consistent with NERC guidelines

VRF and VSL Justifications – COM 003-1, R2			
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:** COM-003-1, Requirement R2 contains only one objective which is to specify clear, formal and universally applied communication protocols that reduce the possibility of miscommunication which could lead to action or inaction harmful to the reliability of BES. Since the requirement has only one objective, only one VRF was assigned.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Responsible Entity ~~responsible entity~~ did not include one (1) of the two (2) parts of Requirement R2, Parts 2.1 to 2.2 in their documented communication protocols	The Responsible Entity ~~responsible entity~~ did not include Parts 2.1 to 2.~~3~~ 2 (~~3~~2) of Requirement R2, in their documented communication protocols OR The responsible entity did not have documented communication protocols as required in Requirement R2. OR The Responsible Entity did not implement, in a manner that identifies, assesses and corrects deficiencies, their documented

VRF and VSL Justifications – COM 003-1, R2			
			communication protocols as required in Requirement R1

VRF and VSL Justifications – COM 003-1, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Based on the VSL Guidance, the SDT developed ~~four~~ two VSLs based on misapplication or absence of common communication protocols. If no communication protocols are used at all or if the number of required protocols falls below the listed thresholds, then the VSL is Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement

VRF and VSL Justifications – COM 003-1, R2	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – COM-003-1, R3	
Proposed VRF	Medium
NERC VRF Discussion	R3 is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of the requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Medium" which is consistent with NERC guidelines
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report:** R3 falls under Recommendation 24 of the Blackout Report. The VRF for this requirement is "Medium" which is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard :** The requirement has sub-requirements that are of equal importance and similarly address communication protocols; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards:** This requirement calls for use of formal three part communication, among other communication protocols. This requirement is analogous to R2 of COM-002-2, which describes a communication protocol required for operating personnel to use when given a directive. The VRF for this requirement (COM-002-2, R2) is "Medium" which is consistent with COM-003-1 R3 at a "Medium". The SDT considers "Medium" as the proper assignment because it is consistent with NERC and FERC guidelines.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs:** Failure to utilize formal communication protocols could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of the requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Medium" which is consistent with NERC guidelines
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:** COM-003-1, Requirement R3 contains only one objective which is to implement a process for identifying

VRF and VSL Justifications – COM-003-1, R3			
	deficiencies with adherence to the documented communication protocols. Since the requirement has only one objective, only one VRF was assigned.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Responsible Entity does not have a process for identifying deficiencies with adherence to the documented communication protocols specified in Requirement R1; Or The Responsible Entity did not evaluate their process based on deficiencies found external to Part 3.1 to determine whether modification of the process is necessary; Or The Responsible Entity did not implement modifications to the process when the evaluation

VRF and VSL Justifications – COM-003-1, R3			
			determined that modification of the process was necessary to address the deficiencies found; Or The Responsible Entity did not demonstrate that no modification to the process was necessary to address the deficiencies found external to Part 3.1.

~~VRF and VSL Justifications – COM-003-1, R3~~	
~~FERC VSL G1~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~Since R3 represents a new approach that does not currently exist, the VSL does not lower the current level of compliance.~~
~~FERC VSL G2~~ ~~Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties~~ ~~Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent~~ ~~Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language~~	~~Guideline 2a:~~ ~~The VSL assignment for R3 is binary and Severe.~~ ~~Guideline 2b:~~ ~~The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~
~~FERC VSL G3~~ ~~Violation Severity Level Assignment Should Be Consistent with the~~	~~The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement~~

VRF and VSL Justifications – COM-003-1, R3	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non-CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non-CIP

VRF and VSL Justifications – COM-003-1, R4	
Proposed VRF	Medium
NERC VRF Discussion	R4 is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of the requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Medium" which is consistent with NERC guidelines
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report:** R4 falls under Recommendation 24 of the Blackout Report. The VRF for this requirement is "Medium" which is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard :** The requirement has sub-requirements that are of equal importance and similarly address communication protocols; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards:** This requirement calls foruse of formal three part communication, among other communication protocols. This requirement is analogous to R2 of COM-002-2, which describes a communication protocol required for operating personnel to use when given a directive. The VRF for this requirement (COM-002-2, R2) is "Medium" which is consistent with COM-003-1 R4 at a "Medium". The SDT considers "Medium" as the proper assignment because it is consistent with NERC and FERC guidelines.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs:** Failure to utilize formal communication protocols could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of the requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Medium" which is consistent with NERC guidelines
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:** COM-003-1, Requirement R4 contains only one objective which is to implement a process for identifying

VRF and VSL Justifications – COM-003-1, R4			
	deficiencies with adherence to the documented communication protocols. Since the requirement has only one objective, only one VRF was assigned.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Responsible Entity does not have a process for identifying deficiencies with adherence to the documented communication protocols specified in Requirement R2; Or The Responsible Entity did not evaluate their process based on deficiencies found external to Part 4.1 to determine whether modification of the process is necessary; Or The Responsible Entity did not implement modifications to the process when the evaluation

VRF and VSL Justifications – COM-003-1, R4			
			determined that modification of the process was necessary to address the deficiencies found; Or The Responsible Entity did not demonstrate that no modification to the process was necessary to address the deficiencies found external to Part 4.1.

VRF and VSL Justifications – COM-003-1, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Since R4 represents a new approach that does not currently exist, the VSL does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R4 is binary and Severe. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement

VRF and VSL Justifications – COM-003-1, R4	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non-CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non-CIP

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Standard Processes Manual Revisions to Implement SPIG Recommendations

The Standard Processes Manual (SPM) Drafting Team thanks all commenters who submitted comments on the SPM revisions. These SPM revisions were posted for a 45-day public comment period from August 29, 2012 through October 12, 2012. Stakeholders were asked to provide feedback on the revisions and associated documents through a special electronic comment form. There were 67 sets of comments, including comments from approximately 160 different people from approximately 122 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

1. In response to stakeholder feedback about changes to the commenting process, the SCPS clarified that all written comments received via informal feedback will be posted and that while drafting teams are not required to provide a written response to each individual comment received, the teams are encouraged to post a summary response that identifies how it used comments submitted by stakeholders (addressed in section 4.5). The SCPS revised sections 4.12 and 4.13 to clarify the requirements to consider and respond to all written comments.....16

2. In the first posted draft of the SPM, the SCPS proposed handling 'no' votes without comments or with unrelated comments in the way that ANSI recommends – by counting those votes toward quorum but not toward the calculation of consensus, with a detailed evaluation for determining whether a comment is relevant. With this proposed change, the SCPS was trying to encourage stakeholders to only submit the kind of constructive comments that help standard drafting teams improve the standard and reach technical consensus. Based on the comments received, the SPM has re-examined this issue and determined that the approach for evaluating the relevance of comments requires additional clarification, so it has eliminated the process for reviewing the relevance of comments from the proposed revisions. However, the SCPS has retained the concept of including 'no' ballots that are not accompanied by comments in the calculation of quorum, but not being counted in the calculation of consensus. Do you support this modified proposal for handling 'no' votes?.....42

3. Many stakeholders supported the SCPS's proposal to move measures from standards into Reliability Standards Audit Worksheets (RSAWs), as in most cases, measures included in standards are little more than a repeat of the requirement (offering little value to registered entities and compliance auditors). Under the proposed new process, measures will indeed be moved from standards to RSAWs, and the standard drafting team and compliance staff will collaborate to develop the RSAW alongside the standard to ensure consistency from early on in the standards project. As proposed in the first posting, the RSAW will then be posted alongside the standard during the final 45-day comment period, and the RSAW will be subject to a non-binding poll and ultimately presented to NERC's BOT for information. This process is already being piloted, and lessons learned during the pilot will be applied if this proposed process continues. Do you support the proposal to move measures to RSAWs and have drafting teams and compliance staff collaborate on RSAW development, as proposed in the first posting and again in the latest posted revisions to the SPM?.....57

4. In the first posted revisions to the SPM, the SCPS proposed eliminating Violation Risk Factors (VRFs) and the Violation Severity Levels (VSLs) to address several issues identified in the SPIG recommendations. Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional

clarification. Therefore, the proposed revisions to eliminate the VRFs and VSLs will be removed from the next draft of the SPM. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop concepts in response to the SPIG recommendations to ease the burden on the drafting teams and shorten development time frames associated with standard development projects – including strategies for eliminating VRFs and VSLs while maintaining the ERO's focus on the potential risk to the reliability of the BES. Do you support the continued use of VRFs and VSLs as the SCPS works towards a more effective solution for eliminating them from the standards process?.....45

5. Section 7.0 of the SPM, which concerns interpretations, was revised to ensure that stakeholders have a common understanding of what aspects of a standard may be addressed by an interpretation. Only requirements require technical expertise to interpret, and those kinds of interpretations thus require the traditional utilization of a drafting team. Other less technical questions, like a concern about an effective date, do not require the formation of a drafting team and ballot pool and all the associated processing. The SCPS does want to provide stakeholders the ability to maintain control over how interpretations are developed, but the interpretation process in its entirety can lead to large volumes of work and the delay of processing high-priority standards projects. With the revisions proposed in the posted SPM, the SC aims to increase transparency about the handling of interpretations, with the goal of reducing the number of rejected interpretations and ultimately decreasing the interpretation-related burden on drafting teams and stakeholders. Do you agree that this clarification on the use of interpretations will be useful?.....54

6. In the first posted revisions to the SPM, the SCPS proposed the addition of section 16.0, which introduced a waiver provision to allow the SC some flexibility in administering the standards process to meet reliability needs. In other words, the waiver process allows the SC to modify the standards process in rare cases for good cause. Many stakeholders were concerned about this addition, but the SCPS continues to believe that a waiver provision is essential for giving the SC, and thus the industry, the ability to act expeditiously when necessary for reliability (e.g., in responding to regulatory directives in a timely manner). The waiver provision would not give the SC unilateral power in modifying the process, but would require a presentation to the BOT explaining the need for the use of waiver. It could only be utilized if the BOT supported the explanation for the need of the waiver. With this additional clarification, can you support the addition of the waiver provision in section 16.0?.....107

7. If you have any other comments on these proposed revisions that you haven't already mentioned above, please provide them here.....84

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Randi Heise	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike	Garton	NPCC	5, 6
2.	Michael	Crowley	SERC	1, 5, 6
3.	Louis	Slade	RFC	5, 6
4.	Connie	Lowe	MRO	5, 6

2.	Group	Guy Zito	NPCC										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council,LLC	NPCC	10
2.	Carmen Agariloai	Independent Electricity System Operator	NPCC	2
3.	Gregory Campoli	New York Independent System Operator	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

4.	Sylvain Clermont	Hydro Quebec Trans Energie	NPCC	1
5.	Chris De Graffenried	Consolidated Edison Co. of NY	NPCC	1
6.	Gerry Dunbar	NPCC	NPCC	10
7.	Kathleen Goodman	ISO-New England	NPCC	2
8.	Michael Jones	National Grid	NPCC	1
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1
10.	Michael Lombardi	Northeast Utilities	NPCC	1
11.	Randy Mac Donald	New Brunswick Power Transmission	NPCC	9
12.	Bruce Metruck	New York State Power Authority	NPCC	6
13.	Silvia Parada Mitchell	Next Era Energy	NPCC	5
14.	Lee Pedowicz	NPCC	NPCC	10
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1
16.	Si Truc Phan	Hydro Quebec TransEnergie	NPCC	1
17.	David Ramkalawan	Ontario Power Generation	NPCC	5
18.	Brian Robinson	Utility Services	NPCC	8
19.	Michael Schiavone	National Grid	NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Donald Weaver	New Brunswick System Operator	NPCC	2
22.	Ben Wui	Orange and Rockland Utilities	NPCC	1
23.	Peter Yost	Consolidated Edison Co. of N. Y.y	NPCC	3

3.	Group	Joseph DePoorter	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6
2.	Tom Breene	WPS	MRO	3, 4, 5, 6
3.	Chuck Lawrence	ATC	MRO	1
4.	Jodi Jensen	WAPA	MRO	1, 6
5.	Ken Goldsmith	ALT	MRO	4
6.	Dave Rudolf	BEPC	MRO	1, 3, 5, 6
7.	Kayleigh Wilkerson	LES	MRO	1, 3, 5, 6
8.	Joseph DePoorter	MGE	MRO	3, 4, 5, 6
9.	Scott Nichels	RPU	MRO	4
10.	Terry Harbour	MEC	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

11.	Marie Knox	MISO	MRO	2
12.	Lee Kittelson	OTP	MRO	1, 3, 4, 5
13.	Scott Bos	MPW	MRO	1, 3, 5, 6
14.	Tony Eddleman	NPPD	MRO	1, 3, 5
15.	Mike Brytowski	GRE	MRO	1, 3, 5, 6
16.	Dan Inman	MPC	MRO	1, 3, 5, 6

4.	Group	Ed Skiba	ISO/RTO Council's Standards Review Committee		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ali Miremadi	CA-ISO	WECC	2
2.	Steve Myers	ERCOT	ERCOT	2
3.	Ben Li	IESO	NPCC	2
4.	Kathleen Goodman	ISO-NE	NPCC	2
5.	Greg Campoli	NY-ISO	NPCC	2
6.	Stephanie Monzon	PJM	RFC	2
7.	Charles	Yeung	SPP	2

5.	Group	David Dockery, NERC Reliability Compliance Coordinator	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X			

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

6.	Group	Kent Kujala	Detroit Edison			X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeff DePriest		RFC	3, 4, 5

7.	Group	Steve Alexanderson P.E.	Western Small Entity Comment Group			X	X					X

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ronald Sporseen	Blachly-Lane Electric Cooperative	WECC	3
2.	Ronald Sporseen	Central Electric Cooperative	WECC	3
3.	Ronald Sporseen	Consumers Power	WECC	1, 3
4.	Ronald Sporseen	Clearwater Power Company	WECC	3
5.	Ronald Sporseen	Douglas Electric Cooperative	WECC	3
6.	Ronald Sporseen	Fall River Rural Electric Cooperative	WECC	3
7.	Ronald Sporseen	Northern Lights	WECC	3
8.	Ronald Sporseen	Lane Electric Cooperative	WECC	3
9.	Ronald Sporseen	Lincoln Electric Cooperative	WECC	3
10.	Ronald Sporseen	Raft River Rural Electric Cooperative	WECC	3
11.	Ronald Sporseen	Lost River Electric Cooperative	WECC	3
12.	Ronald Sporseen	Salmon River Electric Cooperative	WECC	3
13.	Ronald Sporseen	Umatilla Electric Cooperative	WECC	1, 3
14.	Ronald Sporseen	Coos-Curry Electric Cooperative	WECC	3
15.	Ronald Sporseen	West Oregon Electric Cooperative	WECC	4
16.	Ronald Sporseen	Pacific Northwest Generating Cooperative	WECC	3, 4, 8
17.	Ronald Sporseen	Power Resources Cooperative	WECC	5

8.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	John Boshears	City Utilities of Springfield	SPP	1, 4
3.	Greg Froehling	Rayburn Country Electric Cooperative	SPP	3
4.	Jonathan Hayes	Southwest Power Pool	SPP	2
5.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
6.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
7.	Stephen McGie	City of Coffeyville	SPP	NA

9.	Group	Brent Ingebrigtson	PPL Corporation NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Lyn Truhe	PPL Electric Utilities	RFC	1
2.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered	RFC	5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

		Entities		
3.	Annette M Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	WECC	5
4.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6
5.	Elizabeth A. Davis	PPL EnergyPlus, LLC	RFC	6
6.	Elizabeth A. Davis	PPL EnergyPlus, LLC	SPP	6
7.	Elizabeth A. Davis	PPL EnergyPlus, LLC	WECC	6

10.	Group	Larry Raczkowski	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William J Smith		RFC	1
2.	Stephan M Kern		RFC	3
3.	Douglas G Hohlbaugh	Ohio Edison	RFC	4
4.	Kenneth J Dresner		RFC	5
5.	Kevin J Querry		RFC	6

11.	Group	John Babik	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson	JEA	FRCC	1
2.	Garry Baker	JEA	FRCC	3

12.	Group	David Dworzak	Edison Electric Institute	X									

Additional members listed here: http://www.eei.org

13.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Solomon	Hoosier Energy	RFC	1
2.	Bill Watson	Old Dominion Electric Cooperative	SERC	3, 4
3.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
4.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
5.	Kevin Lyons	Central Iowa Power Cooperative	MRO	

14.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1. John Sullivan		Ameren Services Company	SERC 1										
2. James Manning		NC Electric Membership Corporation	SERC 1										
3. Jim Kelley		PowerSouth Energy Cooperative	SERC 1										
4. Philip Kleckley		SC Electric & Gas Company	SERC 1										
5. Bob Jones		Southern Company Service	SERC 1										
6. McCall, Richard		NCEMC	SERC 1										
7. David Greene		SERC Reliability Corporation	SERC 10										
8. Amir Najafzadeh		SERC Reliability Corporation	SERC 10										
15.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				
Additional Member		**Additional Organization**	**Region**	**Segment Selection**									
1. Lorissa Jones		Transmission Internal Operations	WECC	1									
2. Erika Doot		Generation Support	WECC	3, 5, 6									
3. Hardev Juj		Planning & Asset Management	WECC	1									
16.	Group	Brenda Hampton	Luminant						X				
Additional Member		**Additional Organization**	**Region**	**Segment Selection**									
1. Mike Laney		Luminant Generation Company LLC	ERCOT	5									
17.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
18.	Individual	Ryan Millard	PacifiCorp	X		X		X	X				
19.	Individual	Jana Van Ness, Director Regulatory Compliance	Arizona Public Service Company	X		X		X	X				
20.	Individual	Jack Cashin	EPSA					X	X				
21.	Individual	Barry Lawson	National Rural Electric Cooperative Association (NRECA)				X						
22.	Individual	Steven Powell	Trans Bay Cable LLC										
23.	Individual	Molly Devine	Idaho Power Co.	X		X							
24.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
25.	Individual	Thomas Lyons	Owensboro Municipal Utilities			X							
26.	Individual	Jim Cyrulewsmki	JDRJC Associates								X		
27.	Individual	Laura Lee	Duke Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
28.	Individual	Steve Rueckert	WECC										X
29.	Individual	Thad Ness	American Electric Power	X		X		X	X				
30.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
31.	Individual	Michelle R. D'Antuono	Occidental Energy Ventures Corp			X		X		X			
32.	Individual	Joe O'Brien	NIPSCO	X		X		X	X				
33.	Individual	Patrick Brown	Essential Power, LLC					X					
34.	Individual	Scott McGough	Georgia System Operations Corporation			X							
35.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
36.	Individual	John Brockhan	CenterPoint Energy Houston Electric L.L.C.	X									
37.	Individual	William O. Thompson	NIPSCO					X					
38.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
39.	Individual	Brian Murphy	NextEra Energy	X		X		X	X				
40.	Individual	David Thorne	Pepco Holdings Inc	X		X							
41.	Individual	Mace Hunter	Lakeland Electric	X		X		X					
42.	Individual	J. S. Stonecipher, PE	City of Jacksonville Beach, FL dba/Beaches Energy Services	X									
43.	Individual	Steven Wallace	Seminole Electric Cooperative, Inc.			X	X	X	X				
44.	Individual	Kathleen Goodman	ISO New England Inc.		X								
45.	Individual	David Jendras	Ameren	X		X		X	X				
46.	Individual	Tracy Sliman	Tri-State G & T	X									
47.	Individual	Jim Howard	Lakeland Electric	X		X		X	X				
48.	Individual	Angie Sheffield	Georgia Transmission Corp.	X									
49.	Individual	Terri Pyle	Oklahoma Gas & Electric	X		X		X					
50.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
51.	Individual	Michael Falvo	Independent Electricity System Operator		X								
52.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
53.	Individual	Clay Young	South Carolina Electric and Gas	X		X		X	X				
54.	Individual	Thomas Hanzlik	SCE&G	X		X		X	X				
55.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
56.	Individual	Steven Powell	Trans Bay Cable LLC	X									
57.	Individual	Patrick Brown	Canadian Electricity Association										
58.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
59.	Individual	dmason	HHWP					X					
60.	Individual	Maggy Powell	Exelon Corporation and its affiliates	X		X	X	X	X				
61.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
62.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
63.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
64.	Individual	Tony Kroskey	Brazos Electric Power Cooperative	X									
65.	Individual	Allen Mosher	American Public Power Association	X		X	X	X	X				
66.	Individual	Jose H Escamilla	CPS Energy	X		X		X					
67.	Individual	Darryl Curtis	Oncor Electric Delivery	X									

IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE.

Organization	Yes or No	Do you agree with another entity's comment?
Dominion	Agree	
Associated Electric Cooperative, Inc. - JRO00088	Agree	NRECA
Luminant	Agree	Edison Electric Institute (EEI)
JDRJC Associates	Agree	MISO/SRC
NIPSCO	Agree	"Reference the comments submitted for NIPSCO by Joe O'Brien."
Seminole Electric Cooperative, Inc.	Agree	NRECA
ISO New England Inc.	Agree	We support the comments submitted by the ISO/RTO Council Standards Review Committee (SRC)
Lakeland Electric	Agree	FMPA
Georgia Transmission Corp.	Agree	NRECA - Barry Lawson
Illinois Municipal Electric Agency	Agree	Florida Municipal Power Agency
Nebraska Public Power District	Agree	MRO NSRF (Midwest Reliability Organization - NERC Standards Review Forum)

Organization	Yes or No	Do you agree with another entity's comment?
Indiana Municipal Power Agency	Agree	Indiana Municipal Power Agency supports the comments submitted by Floriday Municipal Power Agency.
Brazos Electric Power Cooperative	Agree	ACES Power Marketing

Summary Consideration:

An initial ballot of Draft 2 of the proposed revisions to the SPM concluded on October 12, 2012 and received a 63% approval. The SC, its subcommittees, and NERC staff continue to be grateful for the industry support and thoughtful comments on the improvements to the standard development process.

The SCPS and Standards Committee have reviewed all of the comments and made the following substantive changes in response to the comments:

- **VRFs, VSLs, Measures, and RSAWs** - The majority of the commenters recognize the burden that the development of VRFs and VSLs has on SDTs and support the development of potential alternatives. Commenters also expressed support for drafting team participation in developing RSAWs. Both of these items will require collaboration between the Standards Committee, NERC Standards staff, and NERC and Regional Compliance programs to develop and implement. Therefore the SCPS is continuing to work toward the elimination of the VRFs and the VSLs through the development of potential alternatives and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. In the same vein, NERC's Compliance program is working with Regions and stakeholders to develop and implement the Reliability Assurance Initiative (RAI), and as this effort evolves the SC and NERC Standards staff will leverage opportunities to align drafting teams and compliance staff to ensure that the intent of drafting teams is captured in approaches to monitoring compliance.

  While these concepts are further developed, Measures, VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll of VRFs and VSLs will continue to be conducted consistent with current process.

- **Treatment of 'No' Votes During a Final Ballot** - Several commenters identified that during a Final ballot, there is no comment period. There is no obligation in the current SPM to accept comments during a recirculation ballot, and the proposed revisions to the SPM are consistent with the current SPM in that there is no comment period associated with a Final Ballot. Therefore, all 'no' votes submitted in a Final Ballot will count toward determination of both the quorum and consensus. Clarifying language and a new Footnote 24 have been inserted in section 4.11, to clarify this important point. Footnote 24 reads: The Final Ballot is used to confirm consensus achieved during the Formal Comment and Ballot stage. Ballot Pool members voting negative on the Final Ballot will be deemed to have commented or supported the comments of other groups during prior Formal Comment periods.

- **Section 16.0 Waiver Provision** - In response to stakeholders concerns regarding transparency, openness and due process protections, the SCPS incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when

the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee.

- **In addition, stakeholders identified a number of minor typographical errors and minor clarifications. These corrections have been made and are shown in the redline.**

1. **In response to stakeholder feedback about changes to the commenting process, the SCPS clarified that all written comments received via informal feedback will be posted and that while drafting teams are not required to provide a written response to each individual comment received, the teams are encouraged to post a summary response that identifies how it used comments submitted by stakeholders (addressed in section 4.5). The SCPS revised sections 4.12 and 4.13 to clarify the requirements to consider and respond to all written comments. These sections now read:**

   4.12 Consideration of Comments A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted.

   However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an additional ballot will be conducted.

   4.13 Additional Ballots If a stakeholder or ballotter proposes a significant revision to the Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last additional ballot prior to conducting a Final Ballot.

   With these revisions, indicated in redline form in the posted SPM, do you support the proposed the new process for addressing comments?

Summary Consideration:

By far, the majority of concerns by comments on Question 1 were related to the perception that ceasing to require the drafting team to respond individually to each and every submitted comment would negatively affect the quality of the effort made by the drafting team to consider all input. The drafting team discussed this topic in great detail. The SPM revision drafting team has concluded that, while there is some validity to the concerns, the expectation is that much greater gains in efficiency in the process and clarity of the consensus development will greatly outweigh any such negative impacts.

The comment process has been streamlined and revised to allow for summary responses to comments and only one formal comment period during which a drafting team is required to respond to comments in writing. In every case where written comments are accepted, the complete record of comments submitted will be posted as part of the development record of the standard.

The process envisions the use of a variety of methods to collect informal stakeholder feedback on preliminary drafts of its documents, including the use of informal comment periods, webinars, industry meetings, workshops, or other mechanisms. As the drafting team uses the various methods, a robust draft will be developed. Once the draft is ready for posting, it should be a high quality product which already addresses industry concerns.

The 30 day informal comment period has been removed to provide more flexibility in the use of informal mechanisms for collecting feedback from stakeholders. This change is consistent with SPIG Recommendations 1 and 5. There is no ANSI requirement to have informal comment periods for 30 days.

If a drafting team determines that significant changes are needed as a result of a comment period, there is no formal obligation for a drafting team to respond to comments in writing. Rather, drafting teams may make any needed changes and communicate these changes via webinar or other informal methods. Drafting teams are mindful that in order to build consensus it is imperative to be responsive to comments, however, responding in writing to every single comment at every stage of standard development is time-intensive and can be inefficient. For this reason, the ability to provide informal feedback to stakeholders regarding how a team is responding to comments allows for necessary flexibility.

The drafting teams will be encouraged to reach out to commenters for explanation of any comments they do not understand. In addition, although the drafting teams are not allowed to receive one-on-one comments from individual commenters, which could be perceived to be biased or unequal access to the process, commenters are free to attend any public meeting of the drafting team and give input at that meeting.

The drafting teams will be encouraged to develop a summary of actions taken to make changes or other disposition of comments received. Although the drafting teams will not be required to develop individual summaries, the background information provided at the beginning of documents posted will explain what is being posted and why. The drafting teams almost certainly will find action summaries to be very useful in developing the document postings.

Following a substantive change, a proposal will again be posted for a 45 day comment period and ballot, accompanied by an explanation of the major changes proposed in the revised proposal. Once a drafting team has responded to comments in writing, a proposal may proceed to the Final Ballot. These changes reflect the minimum ANSI requirements.

Some comments were received in response to this question raising issues which are more appropriately addressed in responses to other questions in the posting. Commenters are encouraged to review all responses to all questions for complete coverage of their comments.

Organization	Yes or No	Question 1 Comment
Western Small Entity Comment Group	No	The comment group objects to summary comment responses. We note that summary comment responses have already been used by some teams, and we find that our comments are not always summarized properly. When the team continues to provide a response, we find they may have not addressed our concerns at all. We fail to see how the summary response will result in an efficiency gain, since more ballots and comment periods will be needed to gather the needed affirmative votes.
Response: The drafting team appreciates your comments. The SDT understands your recommendation and did discuss them. The team continues to support encouraging drafting teams to post a summary response during the informal feedback period that identifies how it used comments submitted by stakeholders, and points to Section 4.12 which requires, in part, that: "All comments received and all responses shall be publicly posted." Additionally, during the balloting process, should you believe your comment was misunderstood or not addressed in the summary of comments, you can either discuss your concerns during an open meeting or directly contact the drafting team to discuss their comments. Please note standard drafting team meetings are open to observers for discussion of multiple perspectives. Additionally, during the balloting process, should your comment not be addressed or misunderstood, please note standard drafting team meetings are open to observers for discussion of multiple perspectives. Also available is the option to directly contact a drafting team chair or member to further discuss any concerns regarding comments.		
ACES Power Marketing Standards Collaborators	No	(1) We simply do not believe that this proposal will have the intended effect of shortening the standards development process. In fact, we believe it will actually lengthen the standards development process in some cases. (2) While

Organization	Yes or No	Question 1 Comment
		the proposal conceptually sounds like a reasonable approach, we are concerned that the actual implementation will result in comments that are not considered appropriately. We have observed that many drafting team's have provided responses to our comments that have indicated they did not fully understand the comments. This results in issues that are raised repeatedly in the future comment phases. The current requirement that a drafting team has to respond to all comments creates a discipline that each comment is at least considered on a cursory basis. This proposal eliminates that discipline which means that comments will be even less likely to be given full consideration. While we understand that comments for some projects (CIP for example) have been so numerous that this approach is not workable for every project, we believe that responding to every comment in writing in most projects is still very manageable. This is especially true if the work is divided up among drafting team participants. Furthermore, even if the drafting team proposes a significant change that will result in an additional ballot per 4.13, we believe it makes sense to respond in writing to all comments to explain how the significant change addresses the comment. Otherwise, the same comment may be re-submitted to the drafting team during the next ballot. (3) The current standards development process has essentially become a "bring me a rock exercise". The drafting team responds to comments and then posts for formal comment and ballot during the next phase. Commenters then submit additional comments often indicating some intricacy of the same or similar issue that the drafting team has not considered fully. Essentially, they say either you did not understand our comments or the proposed changes don't fully address our comments. For major issues, we believe a better approach would be for the drafting team to reach out to commenters in between postings to ensure that the response to comments will address the issue. While this might slightly increase the time in between postings, it is likely to result in fewer postings which results in greater efficiencies. Because NERC requires the commenter to provide contact information when submitting comments, we cannot see any

Organization	Yes or No	Question 1 Comment
		reason this outreach should not occur for the typical standards development effort.
Response: Thank you for your comments. In response to your first comment, it is recognized that it is your opinion that the process may not be shortened by the proposed SPM changes, however, the SCPS does believe that the changes will result in a shorter process and other process benefits. Specific to your second comment, the discipline to consider all comments is intended to continue. There are other options available should you feel that your comments are not specifically addressed. During the balloting process, should your comment not be addressed or misunderstood, please note standard drafting team meetings are open to observers for discussion of multiple perspectives. Also available is the option to directly contact a drafting team chair or member to further discuss any concerns regarding comments. The team continues to support encouraging drafting teams to post a summary response during the informal feedback period that identifies how it used comments submitted by stakeholders, and points to Section 4.12 which requires, in part, that: "All comments received and all responses shall be publicly posted." Additionally, during the balloting process, should you believe your comment was misunderstood or not addressed in the summary of comments, you can either discuss your concerns during an open meeting or directly contact the drafting team to discuss their comments. Please note standard drafting team meetings are open to observers for discussion of multiple perspectives. The intent is for the SDT to use many informal sources of input for the creation of their draft consensus document BEFORE they draft the document and post it for comments and ballot. This process should result in a more robust draft that already contains the majority of the industry consensus input. Regarding your third comment to have the drafting team contact a commenter to discuss responses to their comments, this communication is already available and drafting teams have reached out to commenters to clarify their comment or a particular change would address their concern. Drafting teams are encouraged by NERC to contact commenters to gain better clarification of comments when needed. Your suggestion that the SDT should reach out to commenters is a good one and a revision will be made to the SPM draft to include such activities as a form of informal information gathering to be used between postings/ballots.		
National Rural Electric Cooperative Association (NRECA)	No	NRECA strongly urges the SC to rethink the provisions related to SDT comment response processes. NRECA requests that the SPM be revised to require, not only encourage, a SDT to post a summary response that identifies how it used stakeholder comments in informal comment periods. Otherwise commenters will not know whether and how their comments were considered until possibly the end of the process. NRECA also strongly urges the SC to revise the SPM to require individual, not summary, comment responses during the final formal

Organization	Yes or No	Question 1 Comment
		comment period. If these provisions are not addressed carefully, it could limit, or appear to limit, the ability of stakeholders to effectively participate in the standard development process. This could potentially bring about an increased number of appeals submitted to NERC due to stakeholders not believing their comments were properly addressed and responded to.
Response: Thank you for your comments. The SDT understands your recommendation and did discuss them. The team continues to support encouraging drafting teams to post a summary response during the informal feedback period that identifies how it used comments submitted by stakeholders, and points to Section 4.12 which requires, in part, that: "All comments received and all responses shall be publicly posted." Additionally, during the balloting process, should you believe your comment was misunderstood or not addressed in the summary of comments, you can either discuss your concerns during an open meeting or directly contact the drafting team to discuss their comments. Please note standard drafting team meetings are open to observers for discussion of multiple perspectives.		
Trans Bay Cable LLC	No	Since NERC is moving towards NOT COUNTING no votes without comment, then they are stating comments are required. If comments are required, then the drafting teams/NERC should directly respond to the comments. A lot of time, money, energy is spent in developing, reviewing and writing comments to provide feedback to standard drafting teams. If NERC would decide allow NEGATIVE or NO votes without comment I would support the recommendation.If significant changes are going to be made to a standard, then I agree a response is not required, but the entity who submitted the comment should be responded to stating their comment will be addressed in the updated standard. Again, a lot of time, effort and man power is put into reading, reviewing and responding to standards.
Response: The drafting team reminds you that Section 4.12 of the draft SPM provides for the following: "Consideration of Comments A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted."		

Organization	Yes or No	Question 1 Comment
Duke Energy	No	Section 4.5 should require, not just encourage, summary responses to informal comments. This is an important part of the dialogue between the industry (those providing the informal comments) and the standard drafting team. Similarly, the standard drafting team should be required in section 4.12 to respond in writing with a summary of the significant revisions identified in consideration of comments submitted.
Response: Thank you for your comments. The SDT understands your recommendation and did discuss them. The team continues to support encouraging drafting teams to post a summary response during the informal feedback period that identifies how it used comments submitted by stakeholders, and points to Section 4.12 which requires, in part, that: "All comments received and all responses shall be publicly posted." Additionally, during the balloting process, should you believe your comment was misunderstood or not addressed in the summary of comments, you can either discuss your concerns during an open meeting or directly contact the drafting team to discuss their comments. Please note standard drafting team meetings are open to observers for discussion of multiple perspectives.		
Ameren	No	A summary response would be acceptable as long as all responses are easily searchable under the commenting entity's name; otherwise, there would be no easy way to learn of response to individual comments and also to compile responses to entity's comments to disseminate internally to SMEs.
Response: Thank you for your comments. Serious consideration was given to your recommendation; however, because the number of commenters may be voluminous, it may be impractical and administratively burdensome to require the drafting team to include all commenters' names. The direction is not to make changes to the SPM to include this additional requirement.		
Consumers Energy	No	Consumers Energy believes it is best for the drafting team to respond to all comments as a normal course of action, as it is then clear to the commenting entity exactly what was done/not done to address their concerns. Also, an explanation of why the drafting team disagrees with a comment may clear up the reason for the comment so the entity making the comment does not carry it forward.

Organization	Yes or No	Question 1 Comment
Response: The drafting team appreciates your comments. The drafting teams are encouraged to provide responses to the written comments in a summary form where possible. The Drafting teams are also encouraged to post a summary response that identifies how it used comments submitted by stakeholders. The intent is to gather stakeholder feedback on a "working document" before the document reaches the point where it is considered the "final draft". **Additionally, during the balloting process, should your comment not be addressed or misunderstood, please note standard drafting team meetings are open to observers for discussion of multiple perspectives. Also available is the option to directly contact a drafting team chair or member to further discuss any concerns regarding comments.**		
Trans Bay Cable LLC	No	Having reviewed summarized comments posted from other standards, knowing the oritinal comment provided and reading the "summarized" version, the meaning and intent of the original comment was lost. Comments should be posted as they are submitted.
Response: Thank you for your comments. The SDT points to Section 4.12 which requires, in part, that: "All comments received and all responses shall be publicly posted." Additionally, during the balloting process, should you believe your comment was misunderstood or not addressed in the summary of comments, you can either discuss your concerns during an open meeting or directly contact the drafting team to discuss their comments. Please note standard drafting team meetings are open to observers for discussion of multiple perspectives.		
Exelon Corporation and its affiliates	No	Exelon supports the revision to remove the 30 day time frame for informal comment periods. This is useful to give flexibility to the informal process. More frequent use of the informal comment periods to gather constructive input in the early stages allows the drafting team to utilize the iteration process without the burden of formal response to comment. More robust use of the informal stages could have been sufficient to render the revisions made to the response to comments provision unnecessary. No clear justification or reasoning is given for how the changes will expedite the development process. Presumably, the assumption is that if SDT members don't have to spend so much time on responding to comments then they can continue with the drafting work. This may be exchanging a workload concern for potential quality and consensus

Organization	Yes or No	Question 1 Comment
		building concerns. The response to comments serves a few purposes for entities - an acknowledgement of the entity voice, an indication of whether the SDT understood the comments, and as a tool for confirming language understanding. It is the communications process between the SDT and technical experts at the voting entities over the iterative process. Putting all responses at the end of the process is summary form may eliminate the value that the response to comments contributed to language development and getting to yes votes.
Response: Thank you for your comments and appreciates your support of the revisions to comments received during the informal feedback period. In large part, your comments correctly summarize the intent of the revisions to the SPM. However, please review the draft Sections 4.12 and 4.13 to see that all comments must be posted and all summary responses must be posted. **There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot.** **If a stakeholder or ballotter proposes a significant revision to the Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to written comments received in the last Additional Ballot prior to conducting a Final Ballot.** **The drafting team agrees that communications is important to make the process successful.**		
Oncor Electric Delivery	No	Process OverviewOncor does not support the new commenting process as proposed. In Section 4.13 it states "If a stakeholder or ballotter proposes a significant revision to the Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such

Organization	Yes or No	Question 1 Comment
		revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot." The proposed process also states that if the Standard Development Team chooses to post the revisions for additional comment and ballot that previous comments do not require a response in writing.Oncor takes the position that when a stakeholder submits a significant revision during the initial formal commenting period which improves the quality, clarity, or enforceability of a Reliability Standard, then, the drafting team would be remiss [“may choose”] not to consider the validity of the comments by providing a written response to stakeholder concerns and by allowing them to participate in an additional ballot.Oncor takes the position that the current language in the ROP should remain as follows.”If a stakeholder or balloter proposes a significant revision to the Reliability Standard during the formal comment period or concurrent initial ballot that will improve the quality, clarity, or enforceability of that Reliability Standard then the drafting team shall make such revisions and post the revised Reliability Standard for another public comment period and ballot.”
Response: Thank you for your comments. The drafting team wishes to clarify that whether to include significant revisions is a decision to be made by the SDT. However, we believe that such revisions which do, in fact, improve the quality, clarity, or enforceability of the Reliability Standard are almost certain to be adopted by the SDT. There may be other decisions or options available which lead the SDT to select a different, equally effective option. In any case, when significant revisions are made, the SDT is not required to spend unnecessary time in responding to all comments. The SDT will notify the commenters that a significant revision will be made and, as a result, an additional posting/ballot will be required. In all cases, prior to the final ballot, the SDT must consider and respond to all remaining comments. The drafting team believes the language included in Sections 4.12 and 4.13 do require what you suggest.		
Kansas City Power & Light	No	
HHWP	No	
MRO NSRF	Yes	Yes, we agree with these changes. We encourage the standard drafting team to

Organization	Yes or No	Question 1 Comment
		post the revised Reliability Standard for another 45 calendar day public comment period and ballot each time a stakeholder or ballotter proposes a significant revision to the Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard.
Response: Thank you for your comments and support. The drafting team wishes to clarify that whether to include significant revisions is a decision to be made by the SDT. However, we believe that such revisions which do, in fact, improve the quality, clarity, or enforceability of the Reliability Standard are almost certain to be adopted by the SDT. There may be other decisions or options available which lead the SDT to select a different, equally effective option. The drafting team believes the new language proposed in Sections 4.12 and 4.13 do require what you suggest.		
SPP Standards Review Group	Yes	While we understand the necessity of streamlining the process by cutting down on the number of responses made to comments, making this change leaves the impression that consideration for all comments received may not be given. We are accustomed to seeing responses to our comments posted in the next draft of a standard. However, the SPM does provide encouragement that all comments will be considered.
Response: Thank you for your comments and support.		
American Electric Power	Yes	The text for 4.12 as provided in the comment form above is shown as 4.12 in the draft, and the text for 4.13 provided in the comment form above is shown as 4.12 in the draft. It would appear that the draft is incorrect and that the format provided in the comment form is correct.
Response: Thank you for your comments and support. We believe that you may have been referencing the June posting of the draft SPM which did have the order of Sections 4.12 and 4.13 reversed.		
Occidental Energy Ventures Corp	Yes	Occidental Energy Ventures Corp (OEVC) agrees that the elimination of a requirement to individually address each stakeholder comment could result in

Organization	Yes or No	Question 1 Comment
		substantial savings in development time. However, we are concerned that if some consideration is not demonstrated, most entities (including us) will likely re-submit the comment during the following review. If this consistently occurs, the result could be extra review cycles - and eliminate the benefit of not developing a response in the first place.
Response: Thank you for your comments and support. We understand your concern and believe it is addressed by the ability of the commenter to either discuss their concerns during an open meeting or directly contact the drafting team to discuss their comments. Please note standard drafting team meetings are open to observers for discussion of multiple perspectives.		
Georgia System Operations Corporation	Yes	This is yes is continguent up additional clarity in providing the response to the comments.
Response: Thank you for your support. Be assured that all comments will be addressed by the drafting teams.		
Oklahoma Gas & Electric	Yes	We understand the need to streamline the stakeholder process; however, the responses to comments can provide valuable information. We are in support of one response for multiple comments that are similar and that the option of not responding to comments be used only when significant changes are needed and additional ballots are conducted.
Response: Thank you for your comments and support.		
EPSA	Yes	See comprehensive comments in Question 7
NPCC	Yes	
ISO/RTO Council's Standards Review Committee	Yes	
Detroit Edison	Yes	

Organization	Yes or No	Question 1 Comment
PPL Corporation NERC Registered Affiliates	Yes	
FirstEnergy	Yes	
JEA	Yes	
SERC Planning Standards Subcommittee	Yes	
Bonneville Power Administration	Yes	
Southern Company	Yes	
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Idaho Power Co.	Yes	
Public Service Enterprise Group	Yes	
Owensboro Municipal Utilities	Yes	
WECC	Yes	
The United Illuminating Company	Yes	
Essential Power, LLC	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 1 Comment
CenterPoint Energy Houston Electric L.L.C.	Yes	
American Transmission Company	Yes	
NextEra Energy	Yes	
Pepco Holdings Inc	Yes	
City of Jacksonville Beach, FL dba/Beaches Energy Services	Yes	
Liberty Electric Power LLC	Yes	
Independent Electricity System Operator	Yes	
South Carolina Electric and Gas	Yes	
American Public Power Association	Yes	
CPS Energy	Yes	
Organization	Yes or No	Question 1 Comment
Western Small Entity Comment Group	No	The comment group objects to summary comment responses. We note that summary comment responses have already been used by some teams, and we find that our comments are not always summarized properly. When the team continues to provide a response, we find they may have not addressed our concerns at all. We fail to see how the summary response will result in an efficiency gain, since more ballots and comment periods will be needed to

Organization	Yes or No	Question 1 Comment
		gather the needed affirmative votes.
Response: The drafting team appreciates your comments. The SDT understands your recommendation and did discuss them. The team continues to support encouraging drafting teams to post a summary response during the informal feedback period that identifies how it used comments submitted by stakeholders, and points to Section 4.12 which requires, in part, that: "All comments received and all responses shall be publicly posted." Additionally, during the balloting process, should you believe your comment was misunderstood or not addressed in the summary of comments, you can either discuss your concerns during an open meeting or directly contact the drafting team to discuss their comments. Please note standard drafting team meetings are open to observers for discussion of multiple perspectives. Additionally, during the balloting process, should your comment not be addressed or misunderstood, please note standard drafting team meetings are open to observers for discussion of multiple perspectives. Also available is the option to directly contact a drafting team chair or member to further discuss any concerns regarding comments.		
ACES Power Marketing Standards Collaborators	No	(1) We simply do not believe that this proposal will have the intended effect of shortening the standards development process. In fact, we believe it will actually lengthen the standards development process in some cases. (2) While the proposal conceptually sounds like a reasonable approach, we are concerned that the actual implementation will result in comments that are not considered appropriately. We have observed that many drafting team's have provided responses to our comments that have indicated they did not fully understand the comments. This results in issues that are raised repeatedly in the future comment phases. The current requirement that a drafting team has to respond to all comments creates a discipline that each comment is at least considered on a cursory basis. This proposal eliminates that discipline which means that comments will be even less likely to be given full consideration. While we understand that comments for some projects (CIP for example) have been so numerous that this approach is not workable for every project, we believe that responding to every comment in writing in most projects is still very manageable. This is especially true if the work is divided up among drafting team participants. Furthermore, even if the drafting team proposes a significant change that will result in an additional ballot per 4.13, we believe it makes sense

Organization	Yes or No	Question 1 Comment
		to respond in writing to all comments to explain how the significant change addresses the comment. Otherwise, the same comment may be re-submitted to the drafting team during the next ballot.(3) The current standards development process has essentially become a "bring me a rock exercise". The drafting team responds to comments and then posts for formal comment and ballot during the next phase. Commenters then submit additional comments often indicating some intricacy of the same or similar issue that the drafting team has not considered fully. Essentially, they say either you did not understand our comments or the proposed changes don't fully address our comments. For major issues, we believe a better approach would be for the drafting team to reach out to commenters in between postings to ensure that the response to comments will address the issue. While this might slightly increase the time in between postings, it is likely to result in fewer postings which results in greater efficiencies. Because NERC requires the commenter to provide contact information when submitting comments, we cannot see any reason this outreach should not occur for the typical standards development effort.
Response: Thank you for your comments. In response to your first comment, it is recognized that it is your opinion that the process may not be shortened by the proposed SPM changes, however, the SCPS does believe that the changes will result in a shorter process and other process benefits. Specific to your second comment, the discipline to consider all comments is intended to continue. There are other options available should you feel that your comments are not specifically addressed. During the balloting process, should your comment not be addressed or misunderstood, please note standard drafting team meetings are open to observers for discussion of multiple perspectives. Also available is the option to directly contact a drafting team chair or member to further discuss any concerns regarding comments. The team continues to support encouraging drafting teams to post a summary response during the informal feedback period that identifies how it used comments submitted by stakeholders, and points to Section 4.12 which requires, in part, that: "All comments received and all responses shall be publicly posted." Additionally, during the balloting process, should you believe your comment was misunderstood or not addressed in the summary of comments, you can either discuss your concerns during an open meeting or directly contact the drafting team to discuss their comments. Please note standard drafting team meetings are open to observers for discussion of multiple perspectives. The intent is for the SDT to use many informal sources of input for the creation of their draft consensus document BEFORE they draft the		

Organization	Yes or No	Question 1 Comment
document and post it for comments and ballot. This process should result in a more robust draft that already contains the majority of the industry consensus input. Regarding your third comment to have the drafting team contact a commenter to discuss responses to their comments, this communication is already available and drafting teams have reached out to commenters to clarify their comment or a particular change would address their concern. Drafting teams are encouraged by NERC to contact commenters to gain better clarification of comments when needed. Your suggestion that the SDT should reach out to commenters is a good one and a revision will be made to the SPM draft to include such activities as a form of informal information gathering to be used between postings/ballots.		
National Rural Electric Cooperative Association (NRECA)	No	NRECA strongly urges the SC to rethink the provisions related to SDT comment response processes. NRECA requests that the SPM be revised to require, not only encourage, a SDT to post a summary response that identifies how it used stakeholder comments in informal comment periods. Otherwise commenters will not know whether and how their comments were considered until possibly the end of the process. NRECA also strongly urges the SC to revise the SPM to require individual, not summary, comment responses during the final formal comment period. If these provisions are not addressed carefully, it could limit, or appear to limit, the ability of stakeholders to effectively participate in the standard development process. This could potentially bring about an increased number of appeals submitted to NERC due to stakeholders not believing their comments were properly addressed and responded to.
Response: Thank you for your comments. The SDT understands your recommendation and did discuss them. The team continues to support encouraging drafting teams to post a summary response during the informal feedback period that identifies how it used comments submitted by stakeholders, and points to Section 4.12 which requires, in part, that: "All comments received and all responses shall be publicly posted." Additionally, during the balloting process, should you believe your comment was misunderstood or not addressed in the summary of comments, you can either discuss your concerns during an open meeting or directly contact the drafting team to discuss their comments. Please note standard drafting team meetings are open to observers for discussion of multiple perspectives.		
Trans Bay Cable LLC	No	Since NERC is moving towards NOT COUNTING no votes without comment, then they are stating comments are required. If comments are required, then the drafting teams/NERC should directly respond to the comments. A lot of

Organization	Yes or No	Question 1 Comment
		time, money, energy is spent in developing, reviewing and writing comments to provide feedback to standard drafting teams. If NERC would decide allow NEGATIVE or NO votes without comment I would support the recommendation.If significant changes are going to be made to a standard, then I agree a response is not required, but the entity who submitted the comment should be responded to stating their comment will be addressed in the updated standard. Again, a lot of time, effort and man power is put into reading, reviewing and responding to standards.
Response: This one needs input from the "No" vote team. I suggest also including the following: The drafting team reminds you that Section 4.12 of the draft SPM provides for the following: "Consideration of Comments A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted."		
Duke Energy	No	Section 4.5 should require, not just encourage, summary responses to informal comments. This is an important part of the dialogue between the industry (those providing the informal comments) and the standard drafting team. Similarly, the standard drafting team should be required in section 4.12 to respond in writing with a summary of the significant revisions identified in consideration of comments submitted.
Response: Thank you for your comments. The SDT understands your recommendation and did discuss them. The team continues to support encouraging drafting teams to post a summary response during the informal feedback period that identifies how it used comments submitted by stakeholders, and points to Section 4.12 which requires, in part, that: "All comments received and all responses shall be publicly posted." Additionally, during the balloting process, should you believe your comment was misunderstood or not addressed in the summary of comments, you can either discuss your concerns during an open meeting or directly contact the drafting team to discuss their comments. Please note standard drafting team meetings are open to observers for discussion of multiple perspectives.		
Ameren	No	A summary response would be acceptable as long as all responses are easily

Organization	Yes or No	Question 1 Comment
		searchable under the commenting entity's name; otherwise, there would be no easy way to learn of response to individual comments and also to compile responses to entity's comments to disseminate internally to SMEs.
Response: Thank you for your comments. Serious consideration was given to your recommendation; however, because the number of commenters may be voluminous, it may be impractical and administratively burdensome to require the drafting team to include all commenters' names. The direction is not to make changes to the SPM to include this additional requirement.		
Consumers Energy	No	Consumers Energy believes it is best for the drafting team to respond to all comments as a normal course of action, as it is then clear to the commenting entity exactly what was done/not done to address their concerns. Also, an explanation of why the drafting team disagrees with a comment may clear up the reason for the comment so the entity making the comment does not carry it forward.
Response: The drafting team appreciates your comments. The drafting teams are encouraged to provide responses to the written comments in a summary form where possible. The Drafting teams are also encouraged to post a summary response that identifies how it used comments submitted by stakeholders. The intent is to gather stakeholder feedback on a "working document" before the document reaches the point where it is considered the "final draft". **Additionally, during the balloting process, should your comment not be addressed or misunderstood, please note standard drafting team meetings are open to observers for discussion of multiple perspectives. Also available is the option to directly contact a drafting team chair or member to further discuss any concerns regarding comments.**		
Trans Bay Cable LLC	No	Having reviewed summarized comments posted from other standards, knowing the oritinal comment provided and reading the "summarized" version, the meaning and intent of the original comment was lost. Comments should be posted as they are submitted.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. The SDT points to Section 4.12 which requires, in part, that: "All comments received and all responses shall be publicly posted." Additionally, during the balloting process, should you believe your comment was misunderstood or not addressed in the summary of comments, you can either discuss your concerns during an open meeting or directly contact the drafting team to discuss their comments. Please note standard drafting team meetings are open to observers for discussion of multiple perspectives.		
Exelon Corporation and its affiliates	No	Exelon supports the revision to remove the 30 day time frame for informal comment periods. This is useful to give flexibility to the informal process. More frequent use of the informal comment periods to gather constructive input in the early stages allows the drafting team to utilize the iteration process without the burden of formal response to comment. More robust use of the informal stages could have been sufficient to render the revisions made to the response to comments provision unnecessary. No clear justification or reasoning is given for how the changes will expedite the development process. Presumably, the assumption is that if SDT members don't have to spend so much time on responding to comments then they can continue with the drafting work. This may be exchanging a workload concern for potential quality and consensus building concerns. The response to comments serves a few purposes for entities - an acknowledgement of the entity voice, an indication of whether the SDT understood the comments, and as a tool for confirming language understanding. It is the communications process between the SDT and technical experts at the voting entities over the iterative process. Putting all responses at the end of the process is summary form may eliminate the value that the response to comments contributed to language development and getting to yes votes.
Response: Thank you for your comments and appreciates your support of the revisions to comments received during the informal feedback period. In large part, your comments correctly summarize the intent of the revisions to the SPM. However, please review the draft Sections 4.12 and 4.13 to see that all comments must be posted and all summary responses must be posted. **There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any**		

Organization	Yes or No	Question 1 Comment
comments submitted during the Final Ballot. If a stakeholder or ballotter proposes a significant revision to the Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to written comments received in the last Additional Ballot prior to conducting a Final Ballot. The drafting team agrees that communications is important to make the process successful.		
Oncor Electric Delivery	No	Process OverviewOncor does not support the new commenting process as proposed. In Section 4.13 it states "If a stakeholder or ballotter proposes a significant revision to the Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot." The proposed process also states that if the Standard Development Team chooses to post the revisions for additional comment and ballot that previous comments do not require a response in writing.Oncor takes the position that when a stakeholder submits a significant revision during the initial formal commenting period which improves the quality, clarity, or enforceability of a Reliability Standard, then, the drafting team would be remiss [“may choose”] not to consider the validity of the comments by providing a written response to stakeholder concerns and by allowing them to participate in an additional ballot.Oncor takes the position that the current language in the ROP should remain as follows.”If a stakeholder or balloter proposes a significant revision to the Reliability Standard during the formal comment period or concurrent initial ballot that will improve the quality, clarity, or enforceability of that Reliability Standard then the drafting team shall

Organization	Yes or No	Question 1 Comment
		make such revisions and post the revised Reliability Standard for another public comment period and ballot."
Response: Thank you for your comments. The drafting team wishes to clarify that whether to include significant revisions is a decision to be made by the SDT. However, we believe that such revisions which do, in fact, improve the quality, clarity, or enforceability of the Reliability Standard are almost certain to be adopted by the SDT. There may be other decisions or options available which lead the SDT to select a different, equally effective option. In any case, when significant revisions are made, the SDT is not required to spend unnecessary time in responding to all comments. The SDT will notify the commenters that a significant revision will be made and, as a result, an additional posting/ballot will be required. In all cases, prior to the final ballot, the SDT must consider and respond to all remaining comments. The drafting team believes the language included in Sections 4.12 and 4.13 do require what you suggest.		
Kansas City Power & Light	No	
HHWP	No	
MRO NSRF	Yes	Yes, we agree with these changes. We encourage the standard drafting team to post the revised Reliability Standard for another 45 calendar day public comment period and ballot each time a stakeholder or ballotter proposes a significant revision to the Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard.
Response: Thank you for your comments and support. The drafting team wishes to clarify that whether to include significant revisions is a decision to be made by the SDT. However, we believe that such revisions which do, in fact, improve the quality, clarity, or enforceability of the Reliability Standard are almost certain to be adopted by the SDT. There may be other decisions or options available which lead the SDT to select a different, equally effective option. The drafting team believes the new language proposed in Sections 4.12 and 4.13 do require what you suggest.		
SPP Standards Review Group	Yes	While we understand the necessity of streamlining the process by cutting down on the number of responses made to comments, making this change leaves the impression that consideration for all comments received may not be given. We are accustomed to seeing responses to our comments posted in the next draft

Organization	Yes or No	Question 1 Comment
		of a standard. However, the SPM does provide encouragement that all comments will be considered.
Response: Thank you for your comments and support.		
American Electric Power	Yes	The text for 4.12 as provided in the comment form above is shown as 4.12 in the draft, and the text for 4.13 provided in the comment form above is shown as 4.12 in the draft. It would appear that the draft is incorrect and that the format provided in the comment form is correct.
Response: Thank you for your comments and support. We believe that you may have been referencing the June posting of the draft SPM which did have the order of Sections 4.12 and 4.13 reversed.		
Occidental Energy Ventures Corp	Yes	Occidental Energy Ventures Corp (OEVC) agrees that the elimination of a requirement to individually address each stakeholder comment could result in substantial savings in development time. However, we are concerned that if some consideration is not demonstrated, most entities (including us) will likely re-submit the comment during the following review. If this consistently occurs, the result could be extra review cycles - and eliminate the benefit of not developing a response in the first place.
Response: Thank you for your comments and support. We understand your concern and believe it is addressed by the ability of the commenter to either discuss their concerns during an open meeting or directly contact the drafting team to discuss their comments. Please note standard drafting team meetings are open to observers for discussion of multiple perspectives.		
Georgia System Operations Corporation	Yes	This is yes is contingent up additional clarity in providing the response to the comments.
Response: Thank you for your support. Be assured that all comments will be addressed by the drafting teams.		
Oklahoma Gas & Electric	Yes	We understand the need to streamline the stakeholder process; however, the responses to comments can provide valuable information. We are in support of

Organization	Yes or No	Question 1 Comment
		one response for multiple comments that are similar and that the option of not responding to comments be used only when significant changes are needed and additional ballots are conducted.
Response: Thank you for your comments and support.		
EPSA	Yes	See comprehensive comments in Question 7
NPCC	Yes	
ISO/RTO Council's Standards Review Committee	Yes	
Detroit Edison	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
FirstEnergy	Yes	
JEA	Yes	
SERC Planning Standards Subcommittee	Yes	
Bonneville Power Administration	Yes	
Southern Company	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 1 Comment
Arizona Public Service Company	Yes	
Idaho Power Co.	Yes	
Public Service Enterprise Group	Yes	
Owensboro Municipal Utilities	Yes	
WECC	Yes	
The United Illuminating Company	Yes	
Essential Power, LLC	Yes	
Manitoba Hydro	Yes	
CenterPoint Energy Houston Electric L.L.C.	Yes	
American Transmission Company	Yes	
NextEra Energy	Yes	
Pepco Holdings Inc	Yes	
City of Jacksonville Beach, FL dba/Beaches Energy Services	Yes	
Liberty Electric Power LLC	Yes	
Independent Electricity System	Yes	

Organization	Yes or No	Question 1 Comment
Operator		
South Carolina Electric and Gas	Yes	
American Public Power Association	Yes	
CPS Energy	Yes	

2. In the first posted draft of the SPM, the SCPS proposed handling 'no' votes without comments or with unrelated comments in the way that ANSI recommends – by counting those votes toward quorum but not toward the calculation of consensus, with a detailed evaluation for determining whether a comment is relevant. With this proposed change, the SCPS was trying to encourage stakeholders to only submit the kind of constructive comments that help standard drafting teams improve the standard and reach technical consensus.

Based on the comments received, the SPM has re-examined this issue and determined that the approach for evaluating the relevance of comments requires additional clarification, so it has eliminated the process for reviewing the relevance of comments from the proposed revisions. However, the SCPS has retained the concept of including 'no' ballots that are not accompanied by comments in the calculation of quorum, but not being counted in the calculation of consensus.

Do you support this modified proposal for handling 'no' votes?

Summary Consideration:

Although a number of commenters expressed concern about discounting negative ballots without comments in the determination or consensus, the SC believes that this is a necessary and reasonable step to provide drafting teams with the information needed to develop a consensus standard. All negative votes with comments, including those votes submitted by balloters that participated in the development of group comments, will count in the determination of both a quorum as well as consensus. Although some commenters identified that this may cause some balloters to submit meaningless comments with their 'no' vote, the SC believes that the opportunity to participate in submitting comments through one of the many industry groups that develop consensus comments provides stakeholders who do not wish to develop their own set of comments with opportunities to inform standard drafting teams of their concerns without resorting to such tactics.

Several commenters identified that during a Final ballot, there is no comment period. There is no obligation in the current SPM to accept comments during a recirculation ballot, and the proposed revisions to the SPM are consistent in that there is no comment period associated with a Final Ballot. Therefore, all 'no' votes submitted in a Final Ballot will count toward determination of both the quorum and consensus. Clarifying language and a new Footnote 24 have been inserted in section 4.11, to clarify this important point. Footnote 24 reads: *The Final Ballot is used to confirm consensus achieved during the Formal Comment and Ballot stage. Ballot Pool members voting negative on the Final Ballot will be deemed to have commented or supported the comments of other groups during prior Formal Comment periods.*

Organization	Yes or No	Question 2 Comment
Detroit Edison	No	On page 6- I disagree with the last part of the statement. the requirement to a add a comment to a negative vote should not be required. - A two-thirds majority of the weighted segmentSegment votes cast shall be affirmative. The number of votes cast is the sum of affirmative and negative votes with related comments or stated objections, excluding abstentions and, non-responses., negative votes without comments, and negative votes with unrelated comments.On page 27 under 4.11- requiring a comment for a negative vote is not acceptable
Response: Thank you for your comment. Participation in the NERC Ballot Pools comes with responsibility to participate and be helpful to the process. The value of any comment during the process cannot be underestimated and it is imperative to the NERC Standard Drafting Teams that they know why the entities voted negatively. It is not a burden and provides the drafters with the necessary information to know why their ballot did not achieve consensus and what may be done to improve the quality of the standard in an efficient manner. The reference to "related" comment included in the text box will be struck from the SPM.		
ACES Power Marketing Standards Collaborators	No	(1) We believe that comments in response to the last posting indicated little support for discounting 'no' votes for any reason. Given the comments, we believe the drafting team should eliminate any plan to discount negative votes for any reason until evidence and analysis is presented that demonstrates that 'no' votes without supporting comments has delayed the standard development process significantly. (2) We disagree with counting discounted 'no' votes towards quorum. Some 'no' votes appropriately will not provide constructive feedback for how to improve the standard simply because the balloter believes the standard is unnecessary. Such a balloter may simply choose not to provide a comment because it only slows the drafting team down because they have to respond to the comment. It would be totally inappropriate to discount such a 'no' vote and then count it towards quorum.
Response: Thank you for your comment. The NERC SC has given further consideration to the matter and in this latest draft will not dismiss any no vote with a comment associated with it. The industry needs to be encouraged to submit comments that are helpful to the drafting teams writing the standards. Participation in the NERC Ballot Pools comes with responsibility to participate		

Organization	Yes or No	Question 2 Comment
and be helpful to the process. The value of any comment during the process cannot be underestimated and it is imperative to the NERC Standard Drafting Teams that they know why the entities voted negatively. It is not a burden to either the drafting team or the commenter to review or provide a comment and provides the drafters with the necessary information to know why their ballot did not achieve consensus and what may be done to improve the quality of the standard in an efficient manner. Simply counting all the no votes and not knowing why the entities voted negatively provides no information to the drafting teams to consider making a revision to the satisfaction of these stakeholders. Casting a negative Ballot with no comment slows the process down and the drafting teams won't know what the issues are with the posted standards.		
SERC Planning Standards Subcommittee	No	Even if there are no comments included, a "No" vote should count in the calculation of consensus.
Response: Thank you for your comment. Participation in the NERC Ballot Pools comes with responsibility to participate and be helpful to the process. The value of any comment during the process cannot be underestimated and it is imperative to the NERC Standard Drafting Teams that they know why the entities voted negatively. To submit no votes and not provide the drafting teams with a reason why leads to inefficiencies and contributes to poor productivity.		
Arizona Public Service Company	No	As proposed, essentially all "no" votes are subject to not being counted in the calculation of consensus.
Response: Thank you for your comment however, the latest proposal only would dismiss those "no" votes without comment in the calculation of consensus. This attribute will encourage commenters to provide some information on why they voted negatively.		
Trans Bay Cable LLC	No	Per the ANSI standard document, their standards are "guidelines" for industry practice, such as siesmic standards for buildings. It's not a "regulated" or "audited" standard that has possible financial penalties for violations. Also, within this same update, NERC is requesting to not repond to all comments, so not only do they want more comments, they don't want to respond to them either.
Response: Thank you for your comment. The NERC SC recognizes the difference between ANSI standards and NERC Reliability Standards and it is because of these differences that it is vitally important to have the industry fully participate in the Standard		

Organization	Yes or No	Question 2 Comment
development process by providing thoughtful comments that support their balloting position as a Ballot Pool Member. Although the NERC Standards Development Process is an ANSI accredited process, the NERC Reliability Standards are not filed with, nor approved by ANSI. Therefore a comparison between ANSI standards and NERC Reliability Standards is not an appropriate assessment to draw conclusions from on how the NERC Standard Development Process should be managed. There are different classes of comments. The most important of which is the comment causing a "no" vote. The drafting teams needs the information why an entity is voting against the standard and the industry needs to be encouraged to provide constructive comments in order to move the standards forward in an efficient manner. There is a difference between comments that come out during a ballot versus an informal comment period. The proposal is to consider all comments gathered during all comment periods to consider all concerns. However there will be informal comment periods where comments will not be responded to individually, rather, will be grouped by type and the drafting team is encouraged one response given to each type.		
Owensboro Municipal Utilities	No	OMU does not support the provision where negative votes are elimintated as part of the calculation of consensus, if these votes do not contain comments.
Response: Thank you for your comment. Participation in the NERC Ballot Pools comes with responsibility to participate and be helpful to the process. The value of any comment during the process cannot be underestimated and it is imperative to the NERC Standard Drafting Teams that they know why the entities voted negatively. The drafting teams needs this information and the industry needs to be encouraged to provide constructive comments in order to move the standards forward in an efficient manner.		
NIPSCO	No	Comments should be related and relevent.
Response: Thank you for your comment. As a first step towards ensuring relevancy of comments related to the proposal, NERC is proposing to accept all comments as qualifiers to count a "no" ballot towards consensus.		
Manitoba Hydro	No	Because the text related to negative votes without comments has been deleted from section 4.11 and not replaced with alternate wording, it is now not clear what will happen when someone submits a negative vote without comments.As a related question, we have several voting representative in our entity, but only submit one commenting form on the entity's behalf. Will this be sufficient?

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. "No" ballots without comments will not be counted in the calculation of consensus. If an entity references comments made by others, that response will be sufficient to count the "no" ballot.		
CenterPoint Energy Houston Electric L.L.C.	No	CenterPoint Energy does not agree with the modified proposal for handling "no" votes. The Company agrees with an incentive to provide constructive comments with an entity's "no" vote, however CenterPoint Energy strongly believes if a "no" vote is not to be counted in the calculation of consensus, then the vote should not count towards the calculation of quorum. CenterPoint Energy is concerned that this method has the potential to skew a ballot in favor of passage when that may not be the consensus of industry voters. In addition, the Company believes these "hidden" "no" votes should be posted so that an accurate picture of industry support for a project be displayed for all participants to view. CenterPoint Energy recommends if a "no" vote with no comments is not to be counted toward consensus then that vote should not be counted towards quorum.
Response: Thank you for your comment. Participation in the NERC Ballot Pools comes with responsibility to participate and be helpful to the process. The value of any comment during the process cannot be underestimated and it is imperative to the NERC Standard Drafting Teams that they know why the entities voted negatively. The drafting teams needs this information and the industry needs to be encouraged to provide constructive comments in order to move the standards forward in an efficient manner. NERC Standards Committee does not believe the burden outweighs the benefit of knowing the opinions of those negative ballot positions and why they voted "no". NERC Standard Committee is not considering this attribute to skew the results of the ballot but rather to encourage comments that provide sufficient guidance to the drafting teams. Since the last draft of the SPM, the relevancy qualifier has been dropped and now "any" comment submitted that accompanies a no ballot will qualify that ballot to be counted. All details of the voting will be provided and a recommendation to identify those votes that did not include comments.		
Lakeland Electric	No	Removal of the comments entry field from the ballot screen causes this proposal to be a problem. My concern is that this will cause a burden on the vote compilers to look in the comment files for comments that are related to the "no" or negative vote. One solution may be to provide some type of link to the comments when a negative

Organization	Yes or No	Question 2 Comment
		vote is entered.
Response: Thank you for your comment. NERC Standards Committee is aware of this situation and NERC has committed the resources necessary to accurately identify negative votes with associated comments.		
Tri-State G & T	No	The SCPS should retain the concept of including 'no' ballots in the calculation of the consensus.
Response: Thank you for your comment. Participation in the NERC Ballot Pools comes with responsibility to participate and be helpful to the process. The value of any comment during the process cannot be underestimated and it is imperative to the NERC Standard Drafting Teams that they know why the entities voted negatively. The drafting teams needs this information and the industry needs to be encouraged to provide constructive comments in order to move the standards forward in an efficient manner.		
South Carolina Electric and Gas	No	All votes should be counted in the calculation of consensus.
Response: Thank you for your comment. Participation in the NERC Ballot Pools comes with responsibility to participate and be helpful to the process. The value of any comment during the process cannot be underestimated and it is imperative to the NERC Standard Drafting Teams that they know why the entities voted negatively. The drafting teams needs this information and the industry needs to be encouraged to provide constructive comments in order to move the standards forward in an efficient manner.		
SCE&G	No	All votes should be counted in the calculation of consensus.
Response: Thank you for your comment. Participation in the NERC Ballot Pools comes with responsibility to participate and be helpful to the process. The value of any comment during the process cannot be underestimated and it is imperative to the NERC Standard Drafting Teams that they know why the entities voted negatively. The drafting teams needs this information and the industry needs to be encouraged to provide constructive comments in order to move the standards forward in an efficient manner.		

Organization	Yes or No	Question 2 Comment
Consumers Energy	No	At this time, NERC's ballot tool does not include a mechanism for direct comments with the ballot. It has been stated that a new tool will be in place by the time these revisions take effect. However, until the tool is in place, there is no way to know for certain that the balloter will be able to directly attach comments to their ballot. Therefore, it is still feasible that a negative ballot would be submitted and that NERC would be unable to locate the related comments, thus rendering the ballot as 'no vote' for purposes of calculating the consensus.
Response: Thank you for your comment. NERC Standards Committee is aware of this situation and NERC has committed the resources necessary to accurately identify negative votes with associated comments.		
Trans Bay Cable LLC	No	If industry isn't empowered to have a right for a "NO" or "Negative" vote to have the same weight as a yes vote, regardless of comments, it's no longer a "vote" and we are simply ceding all the authority to the drafting team and NERC when the intent of the legislation was for industry-approved standards. We realize and understand the guiding standards developed by other organizations adhere and support not counting "NO" votes without comment, but as stated by many the other industry standards are only guidelines and carry no punitive damages. Since NERC standards can and do carry punitive damages all registered voting entities should retain their voting rights to vote for or against any standard or revision without comment.
Response: Thank you for your comment. Participation in the NERC Ballot Pools comes with responsibility to actively participate and be helpful to the process. The value of any comment during the process cannot be underestimated and it is imperative to the NERC Standard Drafting Teams that they know why the entities voted negatively. The drafting teams needs this information and the industry needs to be encouraged to provide constructive comments in order to move the standards forward in an efficient manner. The current standards productivity is not meeting the expectations of the regulators and it is important that the drafting teams be given as much information as possible, especially information on why entities voted negatively, to develop standards efficiently and expeditiously. It is burdensome for the drafting teams to continually revise standards to try to gain industry consensus when they don't have all the concerns.		

Organization	Yes or No	Question 2 Comment
HHWP	No	This proposed handling of makes a ballot pool member non-response a more powerful negative voice than a "'no' votes without comments". A "'no' vote without comments" supports the development of a quorum and has no value in the majority vote count, whereas a ballot pool member non-response works against adoption through obstructing the development of a quorum.
Response: Thank you for your comment. NERC Standards Committee recognizes this however the proposal is meant to encourage industry submittal of comments that are the issue of determining the "no" ballots. The value of any comment during the process cannot be underestimated and it is imperative to the NERC Standard Drafting Teams that they know why the entities voted negatively. The drafting teams needs this information and the industry needs to be encouraged to provide constructive comments in order to move the standards forward in an efficient manner. The goal is to provide the Standards Drafting teams with the best opportunity be successful in the development of a standard that supports the reliability objective in the shortest amount of time.		
Oncor Electric Delivery	No	Oncor does not support the proposal for the handling "no" votes. In Section 4.10, it states "Abstentions and, non-responses, and negative votes without comments shall not be counted for the purposes of determining the fractional affirmative vote for a Segment." Section 4.10 also describes that a quorum is established by at least 75% of the members of the ballot pool submitting a response (which includes Negative votes without comment).The rationale used for the elimination of negative votes without comments is consistent with NERC's ANSI accreditation, however, Oncor takes the position that the elimination of Negative votes without comments for the purpose of determining the fractional affirmative vote for a Segment encourages the submission of comments that serve no useful purpose, other than to fulfill the requirement for a comment to accompany a "No" vote. It appears to go against the spirit of fairness and transparency.Oncor takes the position that all votes should be counted for both the quorum and the establishment of the Affirmative vote. Oncor recommends the following language to support that position as prescribed in Section 4.10: "A quorum, which is established by at least 75% of the members of the ballot pool submitting a response with an affirmative vote, a negative vote, or an abstention."Oncor also recommends that the appropriate software to support a more effective process for

Organization	Yes or No	Question 2 Comment
		balloting, commenting and responding be designed and implemented as part of this initiative. The software should simplify the process for correlating "No" votes to comments in a way which supports the SDTs to be able to assemble comments and potential prioritize for review and implementation. Ultimately, streamline the process to ensure constructive input from the industry and be reviewed and potentially implemented to allow for an efficient standards development process.
Response: Thank you for your comment. Participation in the NERC Ballot Pools comes with responsibility to participate and be helpful to the process. The value of any comment during the process cannot be underestimated and it is imperative to the NERC Standard Drafting Teams that they know why the entities voted negatively. The drafting teams needs this information and the industry needs to be encouraged to provide constructive comments in order to move the standards forward in an efficient manner. NERC Standards Committee is aware of the issues of correlation between "no" votes and comment and NERC has committed the resources necessary to accurately identify negative votes with associated comments.		
Kansas City Power & Light	No	
Western Small Entity Comment Group	Yes	The comment group agrees, but is concerned how no votes without comments are determined. It is no longer possible to submit comments along with a ballot; a separate process must be used. In addition, a balloter may rely on comments submitted by someone else within the same entity, another entity, or comments submitted by a group of entities. The individual name may not be present in the entity comments, or may have altered spelling if listed in group comments. Variations of entity names may also differ from ballot to comments. We expect these issues have or will be addressed.
Response: Thank you for your comment. NERC Standards Committee is aware of the issues of correlation between "no" votes and comment and NERC has committed the resources necessary to accurately identify negative votes with associated comments.		
PPL Corporation NERC Registered Affiliates	Yes	The PPL Companies appreciate the work of the drafting team as it tries to create a process that encourages stakeholder participation in creating Standards that are carefully contemplated and well drafted. While the PPL Companies prefer that all

Organization	Yes or No	Question 2 Comment
		'no' votes be counted, regardless of whether they are accompanied by comments, we can support counting only those 'no' votes that are accompanied by comments, as long as there is not any 'litmus test' regarding the relevance of the comments. We believe that the approach for evaluating the relevance of comments does not require additional clarification (as stated in the question above), as this evaluation is unnecessary and should be removed entirely from the process. The PPL Companies also support the utilization of a tool that would alert submitters to the fact that they are submitting no comments along with their ballot, and to the consequences of such an action.
Response: Thank you for your comments. As a first step, the SPM will not apply a litmus test to ascertain a comment's relevancy or validity and proposes to count all "no" ballots with any comment. The suggestion for "alerting a balloter that comment is not included with a negative ballot and will therefore be dismissed" will be communicated to NERC Staff for possible incorporation to the balloting software.		
Bonneville Power Administration	Yes	BPA agrees that additional work needs to be done towards the approach of evaluating the relevance of the comments.
Response: Thank you for your comments.		
EPSA	Yes	See comprehensive comments in Question 7
Response: Thank you for your comment. However EPSA's submittal to Question 7 has no specifics with respect to the "no" ballot counting.		
Occidental Energy Ventures Corp	Yes	OEVC appreciates the project team's decision to remove the allowance for "No" votes with non-relevant comments to be discarded. As an active member in a Trade Association, OEVC will often refer to comments that they submit - and want to be sure that our input will count against the final tally. In addition, we were concerned that someone would make a value judgment on the applicability of our comments, which we believe is not appropriate.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment and support of the proposal. Comments that refer to other's comments will be deemed acceptable.		
Essential Power, LLC	Yes	The SC must ensure that the commenting function is included in the balloting software prior to implementing this change.
Response: Thank you for your comment. NERC Standards Committee is aware and NERC has committed the resources necessary to accurately associate comments with ballots.		
Ameren	Yes	Please consider adding a pop-up window on the web portal to remind the voter that he/she is about to submit a 'no' vote without comments and as such the vote will only be counted in the calculation of quorum, and not in the calculation of consensus".
Response: Thank you for your comment. The suggestion for "alerting a balloter via a "pop-up window" that comment is not included with a negative ballot and will therefore be dismissed" will be communicated to NERC Staff for possible incorporation to the balloting software.		
Liberty Electric Power LLC	Yes	1. There is still language in the section on rationale which discusses the 'relevance' of a comment, this should be deleted.2. Current comment procedure requires the submission of a comment form outside of the voting process. The disqualification of no votes without comment should not occur until there is a process for submitting comments during the vote. Further, comment forms have been quite lengthy at times with dozens of questions. There needs to be a simple method of commenting which assures a commenter will have his no vote counted. Comment forms such as the CIP form, which covers multiple standards, should be disallowed so there is no confusion in this process.
Response: Thank you for your comment.		

Organization	Yes or No	Question 2 Comment
1. Conforming changes will be made to the process manual to be consistent with the latest proposal. 2. The identified shortcomings of the NERC software has been communicated by NERC Standards Committee to NERC staff as suggestions for potential revision to the existing balloting software.		
American Electric Power	Yes	AEP has no objections as currently proposed, however the comment field was removed from balloting earlier this year, and it remains to be seen what approach would be taken to reference and acknowledge comments made using the electronic comment form.
Response: Thank you for your comment. NERC Standards Committee is aware of the commenting issue and NERC has committed the resources necessary to accurately associate comments with ballots. The identified shortcomings of the NERC software has been communicated by NERC Standards Committee to NERC staff as suggestions for potential revision to the existing balloting software.		
Tacoma Power	Yes	Tacoma Power supports the proposed handling of 'no' votes without comments. The process should not be hindered by actions, such as a 'no' vote without comment, that are not productive to building an industry consensus.However, it should be noted that the ability to submit comments with votes has recently been deleted from the process. In addition, there is no current method to link a submitted comment under the commenting process with a vote. Therefore the ability to submit comments with votes must be reinstated.
Response: Thank you for your comment. NERC Standards Committee is aware of the commenting issue and NERC staff has committed the resources necessary to accurately associate comments with ballots. The identified shortcomings of the NERC software has been communicated by NERC Standards Committee to NERC staff as suggestions for potential revision to the existing balloting software.		
NPCC	Yes	
MRO NSRF	Yes	

Organization	Yes or No	Question 2 Comment
SPP Standards Review Group	Yes	
FirstEnergy	Yes	
JEA	Yes	
Southern Company	Yes	
PacifiCorp	Yes	
Idaho Power Co.	Yes	
Public Service Enterprise Group	Yes	
Duke Energy	Yes	
WECC	Yes	
The United Illuminating Company	Yes	
Georgia System Operations Corporation	Yes	
American Transmission Company	Yes	
NextEra Energy	Yes	
Pepco Holdings Inc	Yes	

Organization	Yes or No	Question 2 Comment
City of Jacksonville Beach, FL dba/Beaches Energy Services	Yes	
Oklahoma Gas & Electric	Yes	
Independent Electricity System Operator	Yes	
American Public Power Association	Yes	
CPS Energy	Yes	
Dominion	Yes	
ISO/RTO Council's Standards Review Committee		Regarding the No voting without responses, we recommend NERC change their tool such that the submitter gets an error message unless something is included in the comments field. We find it problematic for the tool to accept a No vote without comments and then exclude the No vote in the opposition count without providing notification to the submitter that their vote will not be counted.As currently drafted and without the changes to the tool, there are inconsistencies between Sections 4.10 and 4.11. Section 4.11 removed the reference that allowed a ballot pool member to submit a negative vote without comment. However, Section 4.10 indicates that negative votes without comments can be submitted but they will not be counted in determining the consensus but will be used in determining quorum. The two sections are inconsistent.
Response: Thank you for your comment. The suggestion for "alerting a balloter via a "pop-up window" that comment is not included with a negative ballot and will therefore be dismissed" will be communicated to NERC Staff for possible incorporation to the balloting software.		

Organization	Yes or No	Question 2 Comment
Exelon Corporation and its affiliates		Exelon accepts the move to require comments with negative votes, though the balloting portal must be revised to accommodate this new requirement.
Response: Thank you for your comment. NERC Standards Committee is aware of the commenting issue and NERC staff has committed the resources necessary to accurately associate comments with ballots. The identified shortcomings of the NERC software has been communicated by NERC Standards Committee to NERC staff as suggestions for potential revision to the existing balloting software.		

3. **Many stakeholders supported the SCPS's proposal to move measures from standards into Reliability Standards Audit Worksheets (RSAWs), as in most cases, measures included in standards are little more than a repeat of the requirement (offering little value to registered entities and compliance auditors).**

   Under the proposed new process, measures will indeed be moved from standards to RSAWs, and the standard drafting team and compliance staff will collaborate to develop the RSAW alongside the standard to ensure consistency from early on in the standards project. As proposed in the first posting, the RSAW will then be posted alongside the standard during the final 45-day comment period, and the RSAW will be subject to a non-binding poll and ultimately presented to NERC's BOT for information. This process is already being piloted, and lessons learned during the pilot will be applied if this proposed process continues.

   Do you support the proposal to move measures to RSAWs and have drafting teams and compliance staff collaborate on RSAW development, as proposed in the first posting and again in the latest posted revisions to the SPM?

Summary Consideration:

Individual commenters were provided with the following response:

The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans.

Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.

Based on the majority of the commenters' responses and the initial ballot results, the industry supports the SCPS in continuing the pursuit of the elimination of the Measures from the Reliability Standards and establishing the process for the collaborative (SDT &

Compliance) development of the companion RSAW during the Standard Development Process. As the details of the 'Reliability Assurance Initiative' are finalized, the SC and SCPS will work with the NERC Compliance Organization to continue the collaboration between the SDTs and the Compliance Organization to produce the accompanying Compliance documents that support the Reliability Standards.

Organization	Yes or No	Question 3 Comment
NPCC	No	Comments: It is important for Stakeholders to be able to provide input into the Measures via the Reliability Standards, specifically to ensure there are not additional Requirements inadvertently incorporated into the RSAWs. Because there is no obligation for NERC to include comments from the Stakeholders in the RSAWs, the Measures should not be moved from the Standards development process.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
ISO/RTO Council's Standards Review Committee	No	We believe it is important for Stakeholders to be able to provide input into the Measures via the Reliability Standards, specifically to ensure there are not additional Requirements inadvertently incorporated into the RSAWs. Since, there is no obligation for NERC to include comments from the Stakeholders in the RSAWs, we do

Organization	Yes or No	Question 3 Comment
		not support moving the Measures from the Standards development process.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
PPL Corporation NERC Registered Affiliates	No	The PPL Companies believe it is important for Stakeholders to be able to provide input into the Measures via the Reliability Standards, specifically to ensure there are not additional Requirements inadvertently incorporated into the RSAWs. Since, there is no obligation for NERC to include comments from the Stakeholders in the RSAWs, the PPL Companies do not support moving the Measures from the Standards development process.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans.		

Organization	Yes or No	Question 3 Comment
Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
SERC Planning Standards Subcommittee	No	We continue to feel that the measures should remain with the standards. Since there is a potential for the measures to modify requirements, the measures should remain subject to industry approval.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
Southern Company	No	The proposed revisions must provide more clarity on the parallel development of Reliability Standards Audit Worksheets (RSAWs) and Reliability Standards. The Standards Committee Process Subcommittee's consideration of initial comments to the first posting of the revised SPM indicate that RSAWs will be posted for industry review and that the new process will include a non-binding poll during the final 45 day comment/ballot period to gauge industry support. We concur with this approach but it is not clear how the latest draft of the SPM incorporates this concept. We do note that Section 3.10 explains how RSAWs will be developed through collaboration

Organization	Yes or No	Question 3 Comment
		of standards drafting teams and NERC Compliance Staff. Additionally, we note that footnote 20 provides more detail in this regard. The uncertainty over where and how stakeholders will have an opportunity to participate should be codified in the illustration provided in the Process for Developing or Modifying a Reliability Standard (Section 4.0, Figure 1).
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
PacifiCorp	No	PacifiCorp does not support the proposal to move measures to RSAWs as revisions to RSAWs are not subject to the same standards balloting process. The absence of a binding process for the rejection or approval of revisions to the RSAW could create inconsistency between the way a standard is written and the way it is measured in the RSAW. PacifiCorp prefers that the measures remain in the standards template to ensure that changes to a standard and to the way a standard is measured are evaluated concurrently within the same document.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures		

Organization	Yes or No	Question 3 Comment
in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
Arizona Public Service Company	No	While we fully support the development and revision of RSAWs by the drafting team at the time of the development/revision, until such time as all Standards are accompanied by RSAWs, the measures within the Standards are a helpful tool for industry to determine auditor focus and intent.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
National Rural Electric Cooperative Association	No	The elimination of Measures from the standards and effectively replacing them with RSAWs creates several issues of concern. With Measures currently a part of the

Organization	Yes or No	Question 3 Comment
(NRECA)		standard there is certainty of these provisions since they cannot be changed outside of the standard development process. RSAWs, on the other hand, are controlled by NERC compliance staff and they can be updated outside of the standard development process. NRECA is concerned that after the proposed SDT role of working collaboratively with NERC compliance on RSAW development, the RSAWs can be revised without the consultation and straw poll provisions of the proposed SPM. There is currently no assurance that NERC compliance will work to avoid revising the RSAWs after the SDT's role is complete. One possible solution if the SDT is no longer in place to perform this task would be to seek SC concurrence with any future RSAW changes. Additionally, it's still unclear what the roles are for NERC staff and the SDTs regarding RSAW development. NRECA requests that further structure be added to the SPM on the respective roles of NERC compliance and the SDTs regarding RSAW development. Without this NRECA is unsure of the role that SDTs will have in this important role.Footnote 7 - The inclusion of the word "technically" potentially creates confusion as it is used here to qualify whether something is part of a standard or not. Something is either part of the standard or not - eliminate the word "technically" from the second line of the footnote. Footnote 33 - In the second line it states that the RSAWs "may" have a non-binding poll. NRECA requests that this be revised to require that a non-binding poll on RSAWs be conducted, similar to how VSLs/VRFs are handled today.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans.		

Organization	Yes or No	Question 3 Comment
Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
Duke Energy	No	Measures should be kept in the standard itself due to the fact that the RSAWs can be changed without industry input after the standard has been approved, but measures are currently an element of the reliability standard subject to industry vote, Board of Trustee and FERC approval. Keeping the measures as part of the Reliability Standard itself provides compliance certainty and ensures they are considered during the Quality Review, ultimately resulting in greater consistency and higher quality of the measures and the standard overall. This change would necessitate adding the Measures to section 4.6 Conduct Quality Review.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
Georgia System Operations Corporation	No	This would be acceptable if the industry had the right to approve the RSAWs.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the		

Organization	Yes or No	Question 3 Comment
majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
Manitoba Hydro	No	If the measures are to be moved into the RSAWs then there should be a binding vote on the RSAWs. There is no obligation by compliance staff and the SDT to make modifications based on comments submitted in non-binding polls. As an example, even though draft CANs are posted for comment, very few comments are ever incorporated into the CANs. A binding poll on measures, whether they are in the standards or RSAWs, will lead to measures that are more acceptable to industry as a whole.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance		

Organization	Yes or No	Question 3 Comment
documents.		
Lakeland Electric	No	I support FMPA comments on this question
Response: Thank you for your comment. However FMPA did not provide comments to this question.		
Ameren	No	(1) Because the RSAW including the measures would be subject only to a non-binding poll, and the SDT is not required to respond to stakeholder comments we provided for the RSAW/Measures. Therefore, we prefer measures to continue as a part of the standard. (2) We also want to guard against additional requirements which may creep into the RSAW/Measures resulting in a scope change of the standard with a non-binding vote.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
Tri-State G & T	No	This is only acceptable if the RSAW is available as a part of the standard, otherwise the entity may not have ready and reasonable access to the expected evidence to show compliance.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and		

Organization	Yes or No	Question 3 Comment
the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
Oklahoma Gas & Electric	No	After further review, we prefer that measures be included in the Standard instead of the RSAW. We do support the RSAW development during the drafting of the Standard since those two documents should be lock-step.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
Oncor Electric Delivery	No	Oncor takes the position that since the RSAW is in itself, not subject to approval by

Organization	Yes or No	Question 3 Comment
		the standards development process, the validity and effectiveness of the measures could be better served by not placing them in the RSAW, but retaining them in the standards and by performing selected improvements to their clarity and their relativeness.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
SPP Standards Review Group	Yes	We very much appreciate the effort to include the drafting teams in the development of the RSAWs in conjunction with NERC compliance and enforcement staff. This will work great on the initial development of the standard and associated RSAW. We do have concerns that down the road there may be changes to the RSAW such that it may no longer be compatible with the standard. The only way to ensure that the content of the RSAW remains consistent with the standard is to involve the drafting team whenever changes are made to the RSAW.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision		

Organization	Yes or No	Question 3 Comment
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FirstEnergy	Yes	FirstEnergy (FE) supports the new process that has the SDT and NERC Compliance Staff working collaboratively to develop the RSAW at the same time that the Standard is being developed.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
ACES Power Marketing Standards Collaborators	Yes	We support the proposal as long as the RSAWs provide real guidance on how compliance will be measured. If the RSAWs become like the measures and some of the current RSAWs by simply repeating the requirement, we would not support the proposal. Furthermore, we request that a link to the RSAW be included in the

Organization	Yes or No	Question 3 Comment
		standard for ease of reference.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
Bonneville Power Administration	Yes	BPA supports this proposal. BPA emphasizes the need for the SDT to have the authority to develop the standard without interference from the compliance staff. BPA agrees that many benefits can be gained from the compliance staff collaborating with the SDT to create the RSAW. The SDT needs to be the author of the standard and the compliance staff needs to be the author of the RSAW once the standard is developed.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans.		

Organization	Yes or No	Question 3 Comment
Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
EPSA	Yes	See comprehensive comments in Question 7.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
Trans Bay Cable LLC	Yes	My team really liked the format of the test RSAW
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans.		

Organization	Yes or No	Question 3 Comment
Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
American Electric Power	Yes	We see the potential benefit of proposing RSAWs during the comment period as it gets the RSAW closer to the original drafting team, however AEP is concerned that industry would now have a very limited say in their content by virtue of the non-binding poll for RSAWs. AEP sees the benefit of having the RSAWs be an attachment of standard itself, thereby serving as a "one stop shop", and affording industry the opportunity to provide comment and vote on the "attached RSAW".
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
Occidental Energy Ventures Corp	Yes	OEVC believes that the project team has addressed many of our concerns that we submitted to the original draft of the Standards Development Process Manual. Although we would still like to see a binding vote on the RSAW, it is essential that its coordinated development with the Reliability Standard is essential to consistency in the findings of violations - a high priority outcome from our perspective.

Organization	Yes or No	Question 3 Comment
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
City of Jacksonville Beach, FL dba/Beaches Energy Services	Yes	We support the concept; however, what almost causes us to cast a "negative" vote is footnote 7. Currently, the industry has control of the Measures as they are part of the balloted standard, albeit, the industry sometimes does not do a good job developing them. With footnote 7, ERO Staff will have unilateral right to change the Measures (and other Compliance Elements) that the industry as a whole currently controls. We believe this is inappropriate. So, while we agree with the concept, we disagree with the proposed governance of measures and retention at minimum which we believe should not be under the unilateral control of ERO Staff.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans.		

Organization	Yes or No	Question 3 Comment
Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		
Liberty Electric Power LLC	Yes	While supportive of this provision, I do note moving the measures from a binding vote to a non-binding poll could cause problems in the future.
Response: Thank you for your comment and support.		
Tacoma Power	Yes	Tacoma Power supports moving the measures to the RSAWs. We believe the measures and the RSAWs should be tools for the industry to understand how the auditors will perform the compliance with the standards. By moving the measures to the RSAWs, we expect to see fewer conflicts between the documents and the quality and clarity of the RSAW can be improved.
Response: Thank you for your comment and support.		
MRO NSRF	Yes	
Detroit Edison	Yes	
JEA	Yes	
Western Small Entity Comment Group	Yes	
Idaho Power Co.	Yes	
Dominion	Yes	

Organization	Yes or No	Question 3 Comment
Public Service Enterprise Group	Yes	
Owensboro Municipal Utilities	Yes	
WECC	Yes	
NIPSCO	Yes	
Essential Power, LLC	Yes	
American Transmission Company	Yes	
NextEra Energy	Yes	
Pepco Holdings Inc	Yes	
Independent Electricity System Operator	Yes	
South Carolina Electric and Gas	Yes	
Trans Bay Cable LLC	Yes	
HHWP	Yes	
Kansas City Power & Light	Yes	
American Public Power	Yes	

Organization	Yes or No	Question 3 Comment
Association		
CPS Energy	Yes	
The United Illuminating Company	Yes	
Exelon Corporation and its affiliates		Exelon appreciates the move to develop compliance tools/RSAWs for comment along-side the proposed standard language. It is valuable to develop compliance tools such as the RSAW concurrently with the standard development. This improves the likelihood that the intent of the standard language will be reflected in the compliance tool. In addition, it is useful for applicable entities to understand the compliance implications and obligation of the standard prior to building a compliance program. However, a concern remains that replacing Measures (currently part of the approved standard) with the RSAW (not part of the standard and subject to future revision) removes the stability of the compliance instruction. While it may be preferable to remove the Measures from the standard to enable revisions to the measures/RSAWs without embarking on a standard revision project, greater discussion of and commitment to the value of stable, durable RSAWs would be helpful.Whatever the compliance tool utilized with the standard, it should request reasonable information, in a clear and concise manner, to assist in audit-prep for both entities and auditors, it should strictly and accurately reflect the standard language and intent, and it should be stable over time so that entities can incorporate RSAW completion into their compliance programs without multiple iterations of RSAWs.
Response: The SCPS thanks all commenters for their input concerning the removal of Measures from the Reliability Standards and the collaborative development of RSAWs between the Standard Drafting Teams and the NERC Compliance Department. Although the majority of the commenters supported the proposed process, the Standard Process Manual has been revised to retain the Measures in the Reliability Standards and eliminate the language describing SDT involvement in the development of the RSAWs. This revision comes at the request of the NERC Compliance Organization to allow sufficient time for the development of the 'Reliability Assurance		

Organization	Yes or No	Question 3 Comment
Initiative' which includes a review of the existing RSAW content, development process and use by the industry and ERO Compliance Organizations. This time also allows the more focused review of the Standards Development Process that was recently discussed at the NERC MRC and BOT meetings in New Orleans. Therefore, the SPM has been revised to eliminate all references to the development of RSAWs. The collaboration between the SDT and the NERC Compliance Organization will continue through the development of the Measures and any accompanying Compliance documents.		

4. In the first posted revisions to the SPM, the SCPS proposed eliminating Violation Risk Factors (VRFs) and the Violation Severity Levels (VSLs) to address several issues identified in the SPIG recommendations. Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification.

Therefore, the proposed revisions to eliminate the VRFs and VSLs will be removed from the next draft of the SPM. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM.

The SCPS will continue to develop concepts in response to the SPIG recommendations to ease the burden on the drafting teams and shorten development time frames associated with standard development projects – including strategies for eliminating VRFs and VSLs while maintaining the ERO's focus on the potential risk to the reliability of the BES.

Do you support the continued use of VRFs and VSLs as the SCPS works towards a more effective solution for eliminating them from the standards process?

Summary Consideration:

The majority of the commenters recognize the burden that the development of VRFs and VSLs has on the SDTs and supports the development of potential alternatives to the existing Enforcement processes (i.e., revisions to the Penalty Matrix that utilizes the VRFs and VSLs exclusively for determining the starting point for enforcement actions). Commenters expressed concerns with the 'Sanctions Table' concepts and the SCPS has re-examined the concepts and has concluded that certain aspects of the proposal require additional clarification. Therefore the SCPS is continuing to work toward the elimination of the VRFs and the VSLs through the development of potential alternatives to the existing Enforcement processes and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. While these concepts are fully vetted, the VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM.

The SPCS recognizes that the development of VRFs and VSLs takes a significant amount of time and potentially extends the duration of standard development projects. The SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition team.

Organization	Yes or No	Question 4 Comment
NPCC	No	Comments: The development of the VRFs and VSLs takes a significant amount of time and effort in the Standards development process. Since the resulting "benefit" does not outweigh the cost of this effort, we suggest these be eliminated.
Response: Thank you for your comment. The NERC SPCS agrees with the commenter in that the development of VRFs and VSLs takes a significant amount of time and potentially extends the life of standard development projects. The SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition team. The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts.		
ISO/RTO Council's Standards Review Committee	No	It has been our experience that the development of the VRFs and VSLs takes a significant amount of time and effort in the Standards development process. Since the resulting "benefit" does not outweigh the cost of this effort, we suggest these be eliminated.
Response: Thank you for your comment. The NERC SPCS agrees with the commenter in that the development of VRFs and VSLs takes a significant amount of time and potentially extends the life of standard development projects. The SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition team. The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC		

Organization	Yes or No	Question 4 Comment
and Regional Enforcement staff to establish a consensus on the concepts.		
ACES Power Marketing Standards Collaborators	No	We can find little correlation between actual penalties and VRFs and VSLS. As a result, we cannot support their continued use in the current form. There have been many proposals to modify the process by which VSLs and VRFs are developed. These proposals have ranged from complete elimination to developing pro forma VSLs that would be used for every requirement to developing a spreadsheet tool that outputs VRFs based on a series of questions. We do not understand why one of these proposals cannot be piloted. Industry and drafting teams simply spend an inordinate amount of time developing and commenting on VSLs. The amount time spent is simply not commensurate with the impact on reliability.
Response: Thank you for your comment. The NERC SPCS agrees with the commenter in that the development of VRFs and VSLs takes a significant amount of time and potentially extends the life of standard development projects. The SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS has further developed guidance for the SDTs to assist with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition team. The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts.		
Southern Company	No	Southern Company raises the following concerns with Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs):We acknowledge the Standard Committee's challenge to address standards development process efficiencies while incorporating various recommendations from the SCPS and the SPIG. We also note that in drafting SPM revisions, the SCPS suspended an approach to eliminate VRFs and VSLs while incorporating a Sanctions Table. We concur with this approach as it may create opportunities for further review and discussion of specific and comprehensive

Organization	Yes or No	Question 4 Comment
		solutions. Certain portions of the SPM create conflicting messages concerning the manner in which compliance elements such as VRFs/VSLs will be developed and approved. Footnote 4 suggests that NERC staff and the BOT will have an opportunity to revise the stakeholder-approved compliance elements if directed by FERC. Sections 4.4.4, 4.9 and 4.16 provide ample description of how drafting teams and NERC staff will work together to develop, ballot and obtain approval of VRFs and VSLs. The Standards Committee should clarify that a stakeholder's participation in the development process will not be minimized as a result of provisions which allow NERC and the BOT to modify stakeholder-approved compliance elements. We recommend elimination of footnote 4 as a way to mitigate potential conflicts.

Response: Thank you for your comments. The NERC SPCS agrees with the commenter in that the development of VRFs and VSLs takes a significant amount of time and potentially extends the life of standard development projects. The SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts.

Footnote 5 has been revised to address the commenters concern as follows:

[5]It is the responsibility of the ERO staff to develop compliance elements for each standard; however while these elements are not ~~technically~~ part of the standard, they are included in the standard and referenced in this manual because the preferred approach to developing these elements is to use a transparent process that leverages the technical and practical expertise of the drafting team and ballot pool. If directed by FERC, NERC may file revisions to compliance elements following approval of the NERC Board of Trustees.

The SPM has undergone minor revisions in regards to the VRFs and VSLs, to improve the clarity of the process without altering the concepts which dictate the development of, the associated non-binding polls, and the ERO responsibilities to ensure that the VFRs and VSLs meet the criteria established by the ERO and the applicable government agencies.

Organization	Yes or No	Question 4 Comment
PacifiCorp	No	PacifiCorp does not support the continued use of VRFs and VSLs as the SCPS works towards a more effective solution for eliminating them from the standards process. VRFs and VSLs are a faulty process to determine the level of severity for a potential violation. The increase in severity levels and risk factors during updates of existing standards provides little constructive information. The inclusion of the VRFs and VSLs in the balloting process (without binding balloting by the industry) is a drain on industry resources and the balloting process and serves no helpful purpose.
Response: Thank you for your comments. The NERC SPCS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards. The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. While the alternatives that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition.		
Arizona Public Service Company	No	Until the SCPS has developed a more effective solution, VRF and VSL should be eliminated. It may take a long time before the process is developed and continuing in the meantime is not advised, because the VRFs and VSLs are not being applied consistently and there is no transparency regarding the fines that are issued.
Response: Thank you for your comments. The NERC SPCS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards. The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In		

Organization	Yes or No	Question 4 Comment
support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition.		
Duke Energy	No	It would be preferable to eliminate the VRFs and VSLs as part of a comprehensive overhaul of the Compliance Monitoring and Enforcement Program in order to alleviate the burden on the Standard Drafting Team.
Response: Thank you for your comments. The NERC SPCS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards. The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition.		
WECC	No	I bleive that the intention behind removing the VRFs and VSLs was sound. I also understand the opposition voiced by the Compliance represenatives from the different regions. I urge the SC and the SCPS to continue pursuing this effort.
Response: Thank you for your comments. The NERC SPCS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards. . The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition.		

Organization	Yes or No	Question 4 Comment
American Electric Power	No	AEP is disappointed that the SPCS has seemingly abandoned the concept of pursuing the elimination of VRFs and VSLs from the standard template in favor of a Sanction Table Reference. We believe it was an opportunity to encourage SPIG to evaluate the current compliance practice that requires 100% compliance at all times, specifically in regards to requirements that have a very large scope and application. For example, these standards have driven entities to track many thousands of individual due dates which must all be met in order to be fully compliant. To track and meet this volume of distinct parameters is not only extremely challenging, but creates a statistical certitude that violations will occur. We suggest that future standards be developed in such a way that promotes the reliability of the BES in a manner which yields a more reasonable volume of milestones and deliverables to track and meet.AEP liked where the SPCS was going in regards to the Sanction Table Reference, and cannot comment on continuing the use of VRFs and VSLs until a newer methodology is proposed. In the meanwhile, AEP encourages the team to continue working towards an effective solution for eliminating VRFs and VSLs from the standards process. It is our hope that this could be accomplished in the near term, rather than years from now.
Response: Thank you for your comments. The NERC SPCS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards. The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition.		
Georgia System Operations Corporation	No	If the VRFs and VSLs are continued to be used in enforcement they should be part of the standard development process.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. The NERC SPCS believes that the best option is to eliminate the VRFs and VSLs from the Reliability Standards. However, the elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. The NERC SCPS agrees with the commenter in that the development of the VRFs and VSLs should remain in the Standard Development Process. While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition.		
NextEra Energy	No	As stated in its original comments NextEra Energy, Inc. (NextEra) does not see the value in the VSLs. NextEra generally favors the approach of eliminating VRFs and VSLs as presented in the original SPIG changes, subject to NextEra's specific comments on the replacement tables.
Response: Thank you for your comments. The NERC SPCS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition.		
Oncor Electric Delivery	No	In the absence of an alternative path, continuing to utilize VRF's and VSL's is the only option. The industry is nearing the 6th year since the implementation of compliance and enforcement, and it seems the appropriate time to revisit the strategic and programmatic framework of compliance and enforcement policies and practices.

Organization	Yes or No	Question 4 Comment
		With a potential shift in the enforcement practices beginning with Find, Fix and Track (FFT) and the internal controls concept (often referred to as "zero defect language") being introduced into standards/RSAWs during the development process, Oncor recommends that SCPS partner with RISC to identify the appropriate framework including participation for this critical initiative.
Response: Thank you for your comments. The NERC SPCS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards. The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition.		
Kansas City Power & Light	No	
MRO NSRF	Yes	We support the SCPS' efforts to create a more effective solution for eliminating VRFs and VSLs from the standards process.
Response: Thank you for the Comments and support of the concepts presented. The NERC SPCS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards. The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma		

Organization	Yes or No	Question 4 Comment
VSL team and the VRF Definition.		
Bonneville Power Administration	Yes	BPA was in the support of the removal during the first phase and understands the industry's concerns regarding developing strategies for eliminating VRFs and VSLs while continuing to focus on the potential risks of the reliability of the BES.
Response: Thank you for the Comments and support of the concepts presented. The NERC SPCS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards. The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition.		
EPSA	Yes	See comprehensive comments in Question 7.
Occidental Energy Ventures Corp	Yes	Although OEVC understands that a significant savings in time could result from the elimination of VRFs and VSLs, we agree that it is premature to proceed down this path. The existing strategy to determine the risk of a violation to the BES has resulted in a level of consistency that is understood by all involved.
Response: Thank you for the Comments and support of the concepts presented. The NERC SPCS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards. The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes		

Organization	Yes or No	Question 4 Comment
associated with standard development projects In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition.		
City of Jacksonville Beach, FL dba/Beaches Energy Services	Yes	However, we encourage expedited action to develop alternatives to VSLs and VRFs.
Response: Thank you for the Comments and support of the concepts presented. The NERC SPCS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards. The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition.		
Ameren	Yes	We believe this is a step in the right direction at this time, and we also encourage efforts by the SDT to move towards a more effective solution for eliminating them from the standards process.
Response: Thank you for the Comments and support of the concepts presented. The NERC SPCS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards. The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and		

Organization	Yes or No	Question 4 Comment
the VRF Definition.		
Tri-State G & T	Yes	An explanation box for Section 3 (p 12) indicates that the VRFs and VSLs are being removed from the standards in this draft. Section 4.4.4 also indicates that the VRFs and VSLs will be developed by the drafting team. Why are VRFs and VSLs removed from the third line of Section 4.8?
Response: Thank you for your comments. The text box (explanation box) on page 10 of the draft SPM will be revised to remove the reference to the elimination of the VRFs and VSLs. Section 4.8 has been revised to include the language specific to VRFs and VSLs. This language was not replaced when the reference to the 'Sanctions Tables' was removed.		
Tacoma Power	Yes	Tacoma Power supports the continued use of the VRFs and VSLs while the SCPS works toward an effective solution for eliminating them.
Response: Thank you for the Comments and support of the concepts presented. The NERC SPCS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards. The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition.		
American Public Power Association	Yes	APPA supports continued use of VRFs and VSLs as inputs to the Sanctions Table but only until such time as consensus can be reached among stakeholders and the regions on the Risk-Based Matrix approach that was proposed by the SCPS. It is essential that NERC identify efficiencies in the standards development process to free up industry, SDT and NERC staff resources to focus on higher value initiatives such as joint development of RSAWS, CEAP and implementation guides and to speed

Organization	Yes or No	Question 4 Comment
		standard development and approval.
Response: Thank you for the Comments and support of the concepts presented. The NERC SPCS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards. The elimination of the VFRs and VSLs requires the development of an alternative to the existing enforcement process. In support of these efforts, the SCPS is further developing alternatives, including, but not limited to, the 'Sanctions Table' concepts originally proposed during the initial formal comment period, and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS is further developing guidance for the SDTs to assist them with the development of the VRFs and VSLs which incorporates the concepts developed by the Pro Forma VSL team and the VRF Definition.		
Detroit Edison	Yes	
Dominion	Yes	
Western Small Entity Comment Group	Yes	
SPP Standards Review Group	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
FirstEnergy	Yes	
JEA	Yes	
SERC Planning Standards Subcommittee	Yes	

Organization	Yes or No	Question 4 Comment
Trans Bay Cable LLC	Yes	
Idaho Power Co.	Yes	
Public Service Enterprise Group	Yes	
Owensboro Municipal Utilities	Yes	
The United Illuminating Company	Yes	
NIPSCO	Yes	
Essential Power, LLC	Yes	
Manitoba Hydro	Yes	
CenterPoint Energy Houston Electric L.L.C.	Yes	
American Transmission Company	Yes	
Pepco Holdings Inc	Yes	
Oklahoma Gas & Electric	Yes	
Liberty Electric Power LLC	Yes	
Independent Electricity	Yes	

Organization	Yes or No	Question 4 Comment
System Operator		
South Carolina Electric and Gas	Yes	
Consumers Energy	Yes	
Trans Bay Cable LLC	Yes	
HHWP	Yes	
Exelon Corporation and its affiliates	Yes	
CPS Energy	Yes	

5. **Section 7.0 of the SPM, which concerns interpretations, was revised to ensure that stakeholders have a common understanding of what aspects of a standard may be addressed by an interpretation. Only requirements require technical expertise to interpret, and those kinds of interpretations thus require the traditional utilization of a drafting team. Other less technical questions, like a concern about an effective date, do not require the formation of a drafting team and ballot pool and all the associated processing.**

   The SCPS does want to provide stakeholders the ability to maintain control over how interpretations are developed, but the interpretation process in its entirety can lead to large volumes of work and the delay of processing high-priority standards projects. With the revisions proposed in the posted SPM, the SC aims to increase transparency about the handling of interpretations, with the goal of reducing the number of rejected interpretations and ultimately decreasing the interpretation-related burden on drafting teams and stakeholders.

   Do you agree that this clarification on the use of interpretations will be useful?

Summary Consideration:

The governing principle of Section 7.0 is laid out in its first paragraph. "A valid interpretation response provides additional clarity about one or more Requirements, *but does not expand on any Requirement and does not explain how to comply with any Requirement*." See Proposed SPM Section 7.0 Revisions at P 1, emphasis added. An Interpretation request is not the appropriate vehicle to identify a gap or perceived weakness in an approved Reliability Standard. Rather, the primary function of an Interpretation request is to provide clarity regarding Requirements. The proper vehicle for the identification of a gap or weakness in a Reliability Standard is a SAR.

Interpretations are balloted in the same manner as Reliability Standards, and through this mechanism, registered entities are very much a part of the interpretation process and are in involved in the approval of the interpretation.

Organization	Yes or No	Question 5 Comment
NPCC	No	Comments: While we agree with clarification on the use of Interpretations, we do not agree that the Interpretations are limited in the cases of "Where an issue can be addressed by an active standard drafting team." or "Where a question has already been addressed in the record." In the first instance, although duplication of effort is

Organization	Yes or No	Question 5 Comment
		not desirable, it is not acceptable that a Responsible Entity may be found in violation and subsequently penalized while awaiting development of a standards development process. In the second instance, if there is a question that has been 'addressed in the record' we believe that this clarity should be incorporated into the Reliability Standard itself.
Response: Thank you for your comments. It is evident that NPCC and NERC share the same objective—that duplication of effort is not desirable. It is this objective that forged the key governing principle regarding interpretations in the SPM: namely that "A valid interpretation response provides additional clarity about one or more Requirements, *but does not expand on any Requirement and does not explain how to comply with any Requirement*." *See* Proposed SPM Section 7.0 Revisions at P 1, *emphasis added*. A SAR has always been and presently remains the best method of clarifying an ambiguity that a Responsible Entity has identified within a reliability standard. Permitting an entity to submit an Interpretation request while the requirement at issue could be addressed by an active standard drafting team would violate this foundational principle, and divert industry attention and resources away from their proper procedural channel. **Regarding #5, "where a question has already been addressed in the record" NPCC states that "if there is a question that has been 'addressed in the record' we believe that this clarity should be incorporated into the Reliability Standard itself." We disagree. If there is a factual question that has been asked and answered in the standard development process or in the record at the Federal Energy Regulatory Commission, an interpretation is inappropriate and would needlessly expend both NERC and industry resources in a duplicative effort.**		
ISO/RTO Council's Standards Review Committee	No	While we agree with clarification on the use of Interpretations, we do not agree that the Interpretations are limited in the cases of "Where an issue can be addressed by an active standard drafting team." or "Where a question has already been addressed in the record." In the first instance, although we understand that duplication of effort is not desirable, it is not acceptable that a Responsible Entity may be found in violation and subsequently penalized while awaiting development of a standards development process. In the second instance, if there is a question that has been 'addressed in the record' we believe that this clarity should be incorporated into the Reliability Standard itself.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comments. It is evident that ISO/RTO and NERC share the same objective—that duplication of effort is not desirable. It is this objective that forged the key governing principle regarding interpretations in the SPM: namely that "A valid interpretation response provides additional clarity about one or more Requirements, *but does not expand on any Requirement and does not explain how to comply with any Requirement*." *See* Proposed SPM Section 7.0 Revisions at P 1, *emphasis added*. A SAR has always been and presently remains the best method of clarifying an ambiguity that a Responsible Entity has identified within a reliability standard. Permitting an entity to submit an Interpretation request while the requirement at issue could be addressed by an active standard drafting team would violate this foundational principle, and divert industry attention and resources away from their proper procedural channel. **Regarding #5, "where a question has already been addressed in the record" ISO/RTO states that "if there is a question that has been 'addressed in the record' we believe that this clarity should be incorporated into the Reliability Standard itself." We disagree. If there is a factual question that has been asked and answered in the standard development process or in the record at the Federal Energy Regulatory Commission, interpretation is inappropriate and would needlessly expend both NERC and industry resources in a duplicative effort.**		
Western Small Entity Comment Group	No	The comment group agrees that non-technical questions do not require the formation of a drafting team, but the revised SPM provides no alternative path to address such questions. The comment group would also like to point out that the Applicability sections of some of the proposed standards are getting very technical, and can see that entities may need clarification on applicability as well as on the requirements.
Response: Thank you for your comments. The Interpretation process is intended to clarify questions regarding specific *requirements*. "A valid interpretation response provides additional clarity about one or more Requirements, *but does not expand on any Requirement and does not explain how to comply with any Requirement*." *See* Proposed SPM Revisions at P 1, *emphasis added*. Any non-technical question would likely refer to another, non-Requirement provision of a reliability standard, and thus violate this core governing principle of SPM Section 7.0. An interpretation request is thus, likely an improper vehicle to submit non-technical questions.		
PPL Corporation NERC Registered Affiliates	No	The PPL Companies support the intent and the majority of the changes to this section, but suggest a change in the last sentence of the first paragraph of Section

Organization	Yes or No	Question 5 Comment
		7.0. Since not all NERC Board of Trustees-approved Standards have a future effective date in the United States, we suggest changing the language to state, "Interpretations will only be provided for Board of Trustees-approved Reliability Standards, and only for the current effective or later versions of the Reliability Standard."Also, while the PPL Companies agree with clarification on the use of Interpretations, we do not agree that the Interpretations are limited in the cases of "Where an issue can be addressed by an active standard drafting team." or "Where a question has already been addressed in the record." In the first instance, although we understand that duplication of effort is not desirable, it is not acceptable that a Responsible Entity may be found in violation and subsequently penalized while awaiting development of a standards development process. In the second instance, if there is a question that has been 'addressed in the record' we believe that this clarity should be incorporated into the Reliability Standard itself. The PPL Companies do not support, as it is currently written, the proposed addition of the paragraph (in Section 7.0) "The NERC Reliability Standards and Legal Staff shall review the final Interpretation to determine whether it has met the requirements for a valid Interpretation. Based on this review, the NERC Reliability Standards and Legal Staff shall make a recommendation to the NERC Board of Trustees regarding adoption." We would support language that made clear "the requirements for a valid interpretation" that the NERC Staff would be using and language that clearly stated that the NERC Staff would only be using such limited requirements in determining its recommendation.

Response: Thank you for your comments. The intent of the language referenced by PPL is to allow Interpretations only for current or future versions of Reliability Standards. Interpretations for no longer effective versions of Reliability Standards should be rejected because they are inconsistent with the purpose of Interpretations- which is to provide clarity and not to provide guidance on compliance. In order to clarify this point, NERC will modify the last sentence of the first paragraph to read "Interpretations will not be provided for versions of reliability standards that are no longer effective."

It is evident that PPL and NERC share the same objective—that duplication of effort is not desirable. It is this objective that forged the key governing principle regarding interpretations in the SPM: namely that "A valid interpretation response provides additional clarity about one or more Requirements, *but does not expand on any Requirement and does not explain how to comply with any*

Organization	Yes or No	Question 5 Comment
		***Requirement*." *See* Proposed SPM Revisions Section 7.0 at P 1, *emphasis added*. A SAR has always been and presently remains the best method of clarifying an ambiguity that a Responsible Entity has identified within a reliability standard. Permitting an entity to submit an Interpretation request while the requirement at issue could be addressed by an active standard drafting team would violate this foundational principle, and divert industry attention and resources away from their proper procedural channel. Interpretations should not be used as a method to shortcut the standard development process.** **If there is a factual question that has been asked and answered in the standard development process, an interpretation is inappropriate and would needlessly expend both NERC and industry resources in a duplicative effort.** **The purpose of the final review of the Interpretation is to ensure that the final product comports with the requirements set forth in the Standard Processes Manual.**
PacifiCorp	No	PacifiCorp understands the concern that the interpretation process may lead to large volumes of work for drafting teams and delay in processing other pending standards projects, but those reasons alone are insufficient to limit an otherwise significant right of registered entities: to request reasonable clarifications or interpretations of approved standards that may otherwise be imprecise as presently drafted. It does not appear reasonable for NERC to focus its efforts on processing "high-priority standards projects" when there is a legitimate and reasonable request by registered entities to seek clarification of current active standards with which entities are already required to comply. To that end, PacifiCorp disagrees with certain of the enumerated example circumstances by which an Interpretation request may be rejected, as they actually appear to target the core reason as to when registered entities may bring legitimate Interpretation requests. For example, rejecting an Interpretation request that "[i]dentifies a gap or perceived weakness in the approved Reliability Standard," fails to align with a common legitimate justification for a request; approved standards or requirements may have an identified gap or weakness that, as written, impact registered entities' ability to have assurance that it may wholly comply. Further, rejecting an Interpretation request "[w]here an issue can be addressed by an active standard drafting team," is insufficient as a general rule to justify a rejection; an active NERC project may not necessarily address the precise issue in the request and there is no telling how long the active drafting team

Organization	Yes or No	Question 5 Comment
		may take with its project, in any event.
Response: Thank you for your comments. The governing principle of Section 7.0 is laid out in its first paragraph. "A valid interpretation response provides additional clarity about one or more Requirements, *but does not expand on any Requirement and does not explain how to comply with any Requirement*." *See* Proposed SPM Section 7.0 Revisions at P 1, *emphasis added*. An Interpretation request is not the appropriate vehicle to identify a gap or perceived weakness in an approved Reliability Standard. Rather, the primary function of an Interpretation request is to provide clarity regarding Requirements. The proper vehicle for the identification of a gap or weakness in a Reliability Standard is a SAR. **Additionally, PacifiCorp cited example #3 of the proposed modifications to Section 7.0 as being insufficient as a general rule to justify a rejection. That example reads "[w]here an issue can be addressed by an active standard drafting team," it may be rejected. PacifiCorp asserted that "an active NERC project may not necessarily address the precise issue in the request and there is no telling how long the active drafting team may take with its project…" We remind PacifiCorp that Interpretations are required to follow the same process as Reliability Standards, and that Interpretations are a Requirement clarification mechanism, not a compliance tool. Going forward, it is intended for RSAWs to be drafted simultaneously with standards, allowing for such issues to be raised during the development process. We refer Pacificorp to the April 2011 Guidelines issued by Standards Committee titled *Guidelines for Interpretation Drafting Teams*. That document lists four explicit prohibitions regarding what an interpretation may not do:** **An interpretation may not:** **• be used to change an approved Reliability Standard or its applicability;** **• address a gap or perceived weakness in the approved Reliability Standard;** **• clarify or interpret sections of an approved Reliability Standard other than the requirements of the standard;** **• provide an opinion on a particular approach to complying with the requirements.** **If there is an issue that can be addressed by a standing drafting team, use of the interpretation process is not appropriate.**		
Trans Bay Cable LLC	No	I would recommend working towards writing more clear standards. They have become more "legal" than industry and thus require more review which leads to

Organization	Yes or No	Question 5 Comment
		more clarifying questions. Make it simple, easy to use.
Response: Thank you for your comment. NERC is continually striving to improve its standard development process by working with all stakeholders to promulgate clear, understandable Reliability Standards. If Trans Bay has any specific comments regarding the proposed modifications to SPM Section 7.0 on Interpretation processes, please make them known so that we may consider such input in drafting the final version of the SPM.		
Georgia System Operations Corporation	No	It could be acceptable if registered entities were involved in the approval of the interpretation.
Response: Thank you for your comment. We remind GSOC that Interpretations are balloted in the same manner as Reliability Standards, and through this mechanism, registered entities are very much a part of the interpretation process and are in involved in the approval of the interpretation.		
NextEra Energy	No	NextEra continues to favor its approach as presented in its original comments that clarifies how interpretations should be addressed.
Response: Thank you for your comment. Please let us know if there are any elements presented in your original comments that are suitable for specific consideration in Section 7.0.		
Ameren	No	The proposal and its intent are good, but without further details (transparency criteria) we cannot support it at this time.
Response: Thank you for your comment. It is unclear to us what Ameren means precisely by" further details (transparency criteria)." The text within the blue box in the upper right-hand corner of the proposed modifications to Section 7.0 defines the scope of this effort: **[c]hanges to Section 7.0 are intended to clarify the basis and process for rejecting an interpretation, consistent with guidance issued by the NERC Board of Trustees in November 2009, and to incorporate some of the elements of the Standards Committee's *Guidelines to Interpretation Drafting Teams*.** **The proposed changes to Section 7.0 are intended to provide additional clarity and transparency to the processing of**		

Organization	Yes or No	Question 5 Comment
Interpretations.		
Kansas City Power & Light	No	
ACES Power Marketing Standards Collaborators	Yes	Overall, we think the section will be helpful but do note a one issue. While we agree that it would be useful for the interpretation drafting team to develop a SAR for a reliability gap that they identified, we disagree with the language in this section that states they must do this. The team members were nominated to fulfill a purpose which is the interpretation of a standard. They were not nominated to write a standard. While many interpretation drafting teams may wish to submit a SAR, team members may decide that it is beyond their commitment and they simply do not have the time. Development of a standard is more time consuming than interpreting a standard.
Response: Thank you for your comment. If ACES's primary concern is that writing a SAR may be too taxing on the time of Interpretation drafting team members, then we are willing to amend the proposed language. Our primary concern is that if a reliability gap is identified by the Interpretation drafting team, it is made known to the Standards Committee without delay. Thus we will not require that a SAR be written, but rather only require that the Standards Committee be notified of the reliability gap.		
Southern Company	Yes	At Section 7.0: Process for Developing an Interpretation, it is not clear why an interpretation request should be rejected when it "identifies a gap or perceived weakness in the approved Reliability Standard." Is this example correct?
Response: We would like to thank Southern for its comments regarding Question #5. Yes, the example provided is correct. **Southern asked for clarification regarding example #2 listed on the first page of the proposed modifications to SPM Section 7.0. These examples illustrate conditions in which an Interpretation Request might be rejected. Specifically, example #2 states that when an Interpretation Request "[i]dentifies a gap or perceived weakness in the approved Reliability Standard" it may be rejected.** **The governing principle of Section 7.0 is laid out in its first paragraph. "A valid interpretation response provides additional clarity about one or more Requirements, *but does not expand on any Requirement and does not explain how to comply with any*****		

Organization	Yes or No	Question 5 Comment
Requirement." ***See*** **Proposed SPM Section 7.0 Revisions at P 1, *emphasis added*. An Interpretation Request is not the appropriate vehicle to identify of a gap or perceived weakness in an approved Reliability Standard. Rather, the primary function of an Interpretation Request is to provide clarity regarding Requirements. The proper vehicle for the identification of a gap or weakness in a Reliability Standard is SAR.** **Additionally, we refer Southern to the April 2011 Guidelines issued by the Standards Committee titled *Guidelines for Interpretation Drafting Teams*. That document lists four explicit prohibitions regarding what an interpretation may not do (please note second item listed):** **An interpretation may not:** **• be used to change an approved Reliability Standard or its applicability;** **• address a gap or perceived weakness in the approved Reliability Standard;** **• clarify or interpret sections of an approved Reliability Standard other than the requirements of the standard;** **• provide an opinion on a particular approach to complying with the requirements.**		
EPSA	Yes	See comprehensive comments in Question 7.
Response: Thank you for your comments. The EPSA comments in Question 7 do not appear to address interpretations.		
Duke Energy	Yes	1) Please expand on the term "plain on its face" in the eighth example of why an Interpretation may be rejected. It is not clear how that will be assessed. 2) As noted in the response to Question 3, Measures should be retained as an element of the reliability standard and should be subject to interpretation as they could require technical expertise to interpret.
Response: We would like to thank Duke for its comments regarding question #5. The term "plain on its face" is meant as it is commonly used to mean something that is clear and unambiguous to a reasonable person. **Duke encouraged NERC to retain Measures as elements of a reliability standard and to permit measures to be subject to Interpretations. However, the governing principle of Section 7.0 is laid out in its first paragraph. "A valid interpretation response**		

Organization	Yes or No	Question 5 Comment
provides additional clarity about one or more Requirements, *but does not expand on any Requirement and does not explain how to comply with any Requirement*." *See* Proposed SPM Section 7.0 Revisions at P 1, *emphasis added*. The primary function of an Interpretation Request is to provide clarity regarding Requirements. **Additionally, we refer Duke to the April 2011 Guidelines issued by the Standards Committee titled *Guidelines for Interpretation Drafting Teams*. That document lists four explicit prohibitions regarding what an interpretation may not do (please note the third item listed):** **An interpretation may not:** **• be used to change an approved Reliability Standard or its applicability;** **• address a gap or perceived weakness in the approved Reliability Standard;** **• clarify or interpret sections of an approved Reliability Standard other than the requirements of the standard;** **• provide an opinion on a particular approach to complying with the requirements.**		
American Electric Power	Yes	In Step 3 of the process flow, it states "If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for rejecting the SAR to the entity...". Should this instead state "shall provide a written explanation for rejecting the Interpretation Request to the entity"?
Response: We would like to thank AEP for its comments regarding Question #5. AEP pointed out a typo in Step 3 of the process flow chart. We thank AEP for identifying this mistake and will fix it.		
Occidental Energy Ventures Corp	Yes	OEVC believes that by instituting a concurrent standard/RSAW review process, the project team has embarked upon a path which will greatly reduce the need for interpretations and Compliance Application Notices. Although never quite perfectly achievable, that is the appropriate goal of the Standards Development process. We have no problem with language that discourages the submission of minor issues into the interpretations process.

Organization	Yes or No	Question 5 Comment
Response: We would like to thank Occidental for its comments regarding Question #5. We are pleased to have its support behind the proposed modifications to SPM Section 7.0.		
MRO NSRF	Yes	
Dominion	Yes	
Detroit Edison	Yes	
SPP Standards Review Group	Yes	
FirstEnergy	Yes	
JEA	Yes	
SERC Planning Standards Subcommittee	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
Idaho Power Co.	Yes	
Public Service Enterprise Group	Yes	
Owensboro Municipal Utilities	Yes	

Organization	Yes or No	Question 5 Comment
NIPSCO	Yes	
Essential Power, LLC	Yes	
CenterPoint Energy Houston Electric L.L.C.	Yes	
American Transmission Company	Yes	
Pepco Holdings Inc	Yes	
City of Jacksonville Beach, FL dba/Beaches Energy Services	Yes	
Oklahoma Gas & Electric	Yes	
Liberty Electric Power LLC	Yes	
Independent Electricity System Operator	Yes	
South Carolina Electric and Gas	Yes	
Trans Bay Cable LLC	Yes	
HHWP	Yes	
American Public Power Association	Yes	

Organization	Yes or No	Question 5 Comment
CPS Energy	Yes	
Oncor Electric Delivery	Yes	
National Rural Electric Cooperative Association (NRECA)		NRECA is not clear on why an interpretation can't be done for the reason listed in item 2. Please support this provision or delete it. Also, in item 8, NRECA requests that clarification be added to the SPM on who determines whether the meaning of a Reliability Standard is plain on its face. In the second to last paragraph of Section 7.0, in the second line after "Based on this review," add "and after passing industry ballot" to clarify this language.

Response: Thank you for your comments. NRECA inquired as to why an Interpretation could not be offered for an Interpretation request that "identifies a gap or perceived weakness in the approved Reliability Standard" as specified in Example #2 on the first page of the proposed modifications to SPM Section 7.0. The governing principle of Section 7.0 is laid out in its first paragraph. "A valid interpretation response provides additional clarity about one or more Requirements, *but does not expand on any Requirement and does not explain how to comply with any Requirement*." *See* Proposed SPM Section 7.0 Revisions at P 1, *emphasis added*. An Interpretation Request is not the appropriate vehicle to identify of a gap or perceived weakness in an approved Reliability Standard. Rather, the primary function of an Interpretation Request is to provide clarity regarding Requirements. The proper vehicle for the identification of a gap or weakness in a Reliability Standard is a SAR.

Additionally, we refer NRECA to the April 2011 Guidelines issued by the Standards Committee titled *Guidelines for Interpretation Drafting Teams*. That document lists four explicit prohibitions regarding what an interpretation may not do (please note the second item listed):

An interpretation may not:

- **be used to change an approved Reliability Standard or its applicability;**
- **address a gap or perceived weakness in the approved Reliability Standard;**
- **clarify or interpret sections of an approved Reliability Standard other than the requirements of the standard;**
- **provide an opinion on a particular approach to complying with the requirements.**

NRECA also requested that clarification be added to the SPM regarding who will determine whether the meaning of a Reliability

Organization	Yes or No	Question 5 Comment
Standard is "plain on its face," as specified in Example #8 of Section 7.0. We direct NRECA to the paragraph immediately preceding the list of examples, which identifies NERC Reliability Standards and Legal Staff as the bodies that will make such a determination, and present their determination to the Standards Committee. **Lastly, NRECA asked us to modify the second to last paragraph of Section 7.0, which reads:** **The NERC Reliability Standards and Legal Staffs shall review the final interpretation to determine whether it has met the requirements for a valid interpretation. Based on this review, the NERC Standards and Legal Staffs shall make a recommendation to the NERC Board of Trustees regarding adoption.** **NRECA requested that in the second sentence, after the phrase "[b]ased on this review," we insert the phrase "and after passing industry ballot." We do not believe that this addition is necessary. Interpretations are balloted in the same manner as Reliability Standards.**		
Exelon Corporation and its affiliates		Additional clarification language should be added to the Section 7.0 Interpretations: o The language should acknowledge that when a project to address an issue raised in an interpretation request changes from an Interpretation project (subject to Section 7.0 provisions) to a standard revision project, it adopts the process for modifying a Reliability Standard (subject to Section 4.0 provisions). o In addition, the development record should accurately reflect the Standards Committee decision to change an Interpretation to a Standard revision including clear discussion of any objections to the decision.Typo: "Staffs" should be singular.
Response: Thank you for your comments. We thank Exelon for its comments regarding Question #5. Exelon requested additional language that would "acknowledge that when a project to address an issue raised in an Interpretation request changes from an Interpretation project (subject to Section 7.0 provisions) to a standard revision project, it adopts the process for modifying a Reliability Standard (subject to Section 4.0 provisions). We will not add this language as we believe this is self-explanatory within the SPM. **Exelon also suggested that the development record accurately reflect the Standards Committee decision to change an Interpretation to a Standard revision, including clear discussion of any objections to the decision. We agree that this information should be reflected in the development record, but we maintain the position that the specific details of what should be included in the development record of a Reliability Standard should not be set forth in the SPM at such a granular level.**		

6. **In the first posted revisions to the SPM, the SCPS proposed the addition of section 16.0, which introduced a waiver provision to allow the SC some flexibility in administering the standards process to meet reliability needs. In other words, the waiver process allows the SC to modify the standards process in rare cases for good cause.**

   Many stakeholders were concerned about this addition, but the SCPS continues to believe that a waiver provision is essential for giving the SC, and thus the industry, the ability to act expeditiously when necessary for reliability (e.g., in responding to regulatory directives in a timely manner). The waiver provision would not give the SC unilateral power in modifying the process, but would require a presentation to the BOT explaining the need for the use of waiver. It could only be utilized if the BOT supported the explanation for the need of the waiver.

   With this additional clarification, can you support the addition of the waiver provision in section 16.0?

Summary Consideration:

Section 16.0 is intended to provide clarity to the Standards Committee's authority to waive provisions of the Standard Processes Manual and limits the circumstances under which the Standards Committee can take such actions. Section 16.0 states that the waiver provision cannot be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard. NERC is firmly committed to the consensus-based stakeholder standards development process that is set out in NERC's Rules of Procedure.

The waiver provision would not violate ANSI. The currently-effective Standard Process Manual already provides a process for the expedited development of Reliability Standards where necessary "to meet an urgent reliability issue such that there isn't time to follow all the steps in the normal Reliability Standards development process." The waiver provision replaces this section in its entirety.

In the currently-effective Standard Process Manual, the section on Processes for Developing a Reliability Standard Related to a Confidential Issue states: "When faced with a national security emergency situation, NERC may use one of the following special processes to develop a Reliability Standard that addresses an issue that is confidential. Reliability Standards developed using one of the following processes shall be called, "special Reliability Standards" *and shall not be filed with ANSI for approval as ANSI standards*." (emphasis added). The concept that certain Reliability Standards will not be filed with ANSI is not a new one to the Standard Processes Manual nor does it jeopardize NERC's accreditation.

The waiver provision is intended as a tool to allow the Standards Committee to manage the standards development process. The Standards Committee is tasked with protecting the "credibility and integrity of the standards development process." See Standards Committee Charter, available here: http://www.nerc.com/files/SC_Charter_clean_for_BOT_approval_20110417.pdf

In response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee of the NERC Board of Trustees.

Organization	Yes or No	Question 6 Comment
NPCC	No	Comments: The SC already has, and has previously, exercised the 'authority' to 'deviate' from the process. However, the current requirement is that the SC must report these 'deviations' to the CCC and Board. With this blanket waiver, the industry would lose the information that may be critical to understanding when and where the process may be broken and, therefore needs to be deviated from.
Response: Thank you for your comments. Section 16.0 specifically provides that the use of the waiver provision will be reported to the Board of Trustees: "The Standards Committee shall report the exercise of this waiver provision to the Board of Trustees prior to adoption of the related Reliability Standard, Interpretation, definition or Variance." **In response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee of the NERC Board of Trustees.** **Therefore, no information regarding the standard development process is lost.**		
MRO NSRF	No	We discourage the use of a waiver process. We do not believe that taking action on reliability directives and standards in a faster fashion will increase the reliability of the grid, but following the standards process that has received consensus from the industry will better lead to a more reliable grid.
Response: Thank you for your comments. The waiver provision is intended to be used under a very limited set of circumstances, for example, where it is necessary to address an urgent reliability issue. The currently-effective Standard Process Manual provides a process for the expedited development of Reliability Standards where necessary "to meet an urgent reliability issue such that		

Organization	Yes or No	Question 6 Comment
there isn't time to follow all the steps in the normal Reliability Standards development process." The waiver provision replaces this section in its entirety. The need for the ability to address urgent reliability issues has been reflected in FERC's orders certifying NERC as the ERO. See for example P 253 of *North American Electric Reliability Corp*., 116 FERC ¶ 61,062 (2006) "in rare instances, the urgent action process may not be sufficiently expedited, such as if necessary to address an imminent threat to national security. We require NERC to address whether the urgent action process, or some other process, can accommodate any such rare circumstances. " **There is a direct relationship between reliability of the grid and the need for the ability to take action on Reliability Standards in a timely manner.**		
ISO/RTO Council's Standards Review Committee	No	We believe the SC already has, and has previously exercised, the 'authority' to 'deviate' from the process. However, the current requirement is that the SC must report these 'deviations' to the CCC and Board. With this blanket waiver, the industry would lose the information that may be critical to understanding when and where the process may be broken and, therefore, needs to be deviated from.
Response: Thank you for your comments. Section 16.0 specifically provides that the use of the waiver provision will be reported to the Board of Trustees: "The Standards Committee shall report the exercise of this waiver provision to the Board of Trustees prior to adoption of the related Reliability Standard, Interpretation, definition or Variance." **In response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee of the NERC Board of Trustees.** **Therefore, no information regarding the standard development process is lost.**		
PPL Corporation NERC Registered Affiliates	No	The PPL Companies believe the Standards Committee already has, and has previously exercised, the authority to deviate from the process. However, the current requirement is that the SC must report these deviations to the CCC and Board. We

Organization	Yes or No	Question 6 Comment
		would support language in this section that more clearly stated the current process, while leaving in place the current requirements for reporting to the CCC and Board.
Response: Response: Thank you for your comments. Section 16.0 specifically provides that the use of the waiver provision will be reported to the Board of Trustees: "The Standards Committee shall report the exercise of this waiver provision to the Board of Trustees prior to adoption of the related Reliability Standard, Interpretation, definition or Variance." **In response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee of the NERC Board of Trustees.** **Section 16.0 is intended to provide clarity to the Standards Committee's authority to waive provisions of the Standard Processes Manual and limits the circumstances under which the Standards Committee can take such actions. In addition, Section 16.0 states that the waiver provision cannot be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard. NERC is firmly committed to the consensus-based stakeholder standards development process that is set out in NERC's Rules of Procedure.**		
ACES Power Marketing Standards Collaborators	No	We cannot support the waiver section in its current form. It is simply too broad. First, the third bullet causes us particular concern. The Standards Committee (SC) and many drafting teams have misinterpreted industry support for modifications of a standard, definition, etc. many times in the past. Thus, based on history, we are not convinced that the SC could accurately determine that a modification has been fully vetted or that the change is so insubstantial on behalf of industry without a ballot. If the purpose of a waiver for an insubstantial change is to streamline errata changes, we suggest this bullet should be modified to state this directly. Second, contrary to the explanation associated with this question, the waiver section simply does not reflect that the Standards Committee (SC) will only utilize the waiver if the BOT supports the use of the waiver. It only requires the SC to report the use of the waiver to the BOT. Furthermore, waiting for approval from the NERC BOT would only slow down the process anyway which defeats the purpose of the waiver. Third, we do not

Organization	Yes or No	Question 6 Comment
		understand what is driving the need for the waiver section. We are not aware of any regulatory deadline for development of a standard that NERC has failed to meet under the existing process.

Response: Thank you for your comments.

With respect to your comment on the third bullet, the intent is to allow drafting teams the flexibility to make limited additional substantive changes for an abbreviated industry comment period, to for example, adopt language proposed by commenters. Such changes would not qualify as errata.

With respect to your suggestion that the BOT approve use of the waiver, in response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.

With respect to your broader concerns about the need for the waiver section, we suggest that in order for the ERO model to be successful, NERC must have the ability to meet regulatory deadlines. Pursuant to section 215(d)(5) of the FPA, the Commission may direct the ERO to submit to the Commission a new or modified Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Standard appropriate to carry out section 215. As the ERO, NERC must be able to comply with a Commission directive pursuant to section 215(d)(5) of the FPA. The Commission has expressed concern that the standard development process can be misused to "delay or block NERC's ability to report to a Commission directive" See North American Electric Reliability Corp., 130 FERC ¶ 61,203 at P 23 (2010).

NERC has failed to meet several Commission-imposed regulatory deadlines and has repeatedly sought extensions from the Commission.

The Commission has continuously expressed concern regarding the amount of time it takes to develop a Reliability Standard.

- ***See North American Electric Reliability Corp.*, 118 FERC ¶ 61,030 at P 31 (2007)("Both in Order No. 672 and in the *Certification Order* we expressed concern with the length of time the ERO process takes to develop a Reliability Standard. The ERO has never, to our knowledge, developed a Reliability Standard under its normal process in four months or**

Organization	Yes or No	Question 6 Comment
		developed an urgent action Reliability Standard in 60 days."). • *North American Electric Reliability Corp. Reliability Standards Development et al.*, 132 FERC ¶ 61,217 (2010)("In its application for certification as the ERO, NERC indicated that under its usual ANSI-accredited process in effect at the time, a Reliability Standard may be developed in as little as four months, or up to 12 to 15 months for a more complex Standard. However, the NERC analysis submitted in this docket indicates that, in practice, it has taken considerably longer, an average processing time of 21.7 months, to develop Reliability Standards. The average processing time is even longer if 'urgent action' Standards are not considered. Given this analysis, the Commission continues to have some concerns regarding NERC's ability to timely develop Reliability Standards.")(internal citations omitted). NERC, the Regional Entities and industry stakeholders have a significant mutual investment in developing a sustainable Reliability Standards program that will maintain the reliability of the bulk power system in North America. The success of the unique Electric Reliability Organization (ERO) model requires NERC to develop and maintain a body of high-quality, effective Reliability Standards. NERC is at risk of losing the confidence of U.S. regulatory authorities and industry executives in its ability to produce standards in a timely and efficient manner. Section 16.0 is intended to provide clarity to the Standards Committee's authority to waive provisions of the Standard Processes Manual and limits the circumstances under which the Standards Committee can take such actions. In addition, Section 16.0 states that the waiver provision cannot be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard. NERC is firmly committed to the consensus-based stakeholder standards development process that is set out in NERC's Rules of Procedure. The Standards Committee is tasked with protecting the "credibility and integrity of the standards development process." *See* Standards Committee Charter, available here: http://www.nerc.com/files/SC_Charter_clean_for_BOT_approval_20110417.pdf.
SERC Planning Standards Subcommittee	No	We do not agree with the latitude granted by this provision. We feel that some industry input, even if abbreviated and burdensome, is preferred over the currently proposed approach.
Response: Thank you for your comments. The waiver provision is intended as a tool to allow the Standards Committee to manage the standards development process. The Standards Committee is tasked with protecting the "credibility and integrity of the standards development process." See Standards Committee Charter, available here:		

Organization	Yes or No	Question 6 Comment
http://www.nerc.com/files/SC_Charter_clean_for_BOT_approval_20110417.pdf. **The Standards Committee is comprised of industry members from each segment. By definition, there is industry input into the consideration by the Standards Committee of the use of the waiver provision under Section 16.0.** **In order to address your concern regarding notice to stakeholders, the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee has been incorporated. We have clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.**		
PacifiCorp	No	PacifiCorp purports that the exercise of a waiver provision will result in a violation of NERC's ANSI-approved standards development process. Additionally, reporting the exercise of a waiver to the Board of Trustees (BOT) prior to adopting a standard is unacceptable. The exercise of the waiver and BOT approval may be separated by years of work by both the Standards Committee (SC) and the Standards Drafting Team (SDT). Each exercise of an SC waiver should have BOT finality so that the BOT will not be pressured to approve any waiver, regardless of the facts, to preserve the substantial body of work that has followed the exercise of waiver by the SC. At a minimum, waivers to the SPM should be preceded by the following: a. The posting of an SC document to the Registered Ballot Body (RBB) that describes the reason for the requested waiver, including the threat to reliability, and what processes would be affected by the waiver. b. A short (10 day) period for accepting RBB comments. c. After comments are received, the SC may either withdraw the waiver or request its expedited approval by the BOT, ensuring that the board is supplied with the comments received. The entire process proposed above could be completed within 30-45 days, causing a minor delay for the (hopefully) rare exercise by the SC of waiving an SPM provision.
Response: The waiver provision would not violate ANSI. The currently-effective Standard Process Manual already provides a process for the expedited development of Reliability Standards where necessary "to meet an urgent reliability issue such that		

Organization	Yes or No	Question 6 Comment
		there isn't time to follow all the steps in the normal Reliability Standards development process." The waiver provision replaces this section in its entirety. **In the currently-effective Standard Process Manual, the section on Processes for Developing a Reliability Standard Related to a Confidential Issue states: "When faced with a national security emergency situation, NERC may use one of the following special processes to develop a Reliability Standard that addresses an issue that is confidential. Reliability Standards developed using one of the following processes shall be called, "special Reliability Standards" and shall not be filed with ANSI for approval as ANSI standards." (emphasis added). The concept that certain Reliability Standards will not be filed with ANSI is not a new one to the Standard Processes Manual nor does it jeopardize NERC's accreditation.** **In order to address your concern regarding the potential lag in reporting to the Board of Trustees, additional language has been added to require reporting of the use of the waiver provision to the Standards Oversight & Technology Committee.** **In order to address your concern regarding notice to stakeholders, the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee has been incorporated. We have clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.** **NERC, the Regional Entities and industry stakeholders have a significant mutual investment in developing a sustainable Reliability Standards program that will maintain the reliability of the bulk power system in North America. The success of the unique Electric Reliability Organization (ERO) model requires NERC to develop and maintain a body of high-quality, effective Reliability Standards. The current trajectory is unsustainable and, without considering significant course correction, the ERO and industry finds itself nearing a critical juncture where alternate methods to accomplish the development of mandatory Reliability Standards has become necessary. NERC is at risk of losing the confidence of U.S. regulatory authorities and industry executives in its ability to produce standards in a timely and efficient manner.** **Adding an additional 30-45 days to the standard development process in order to utilize a waiver as proposed would defeat the very purpose of the waiver provision- which is to add flexibility to the process.**
National Rural Electric Cooperative Association	No	NRECA presumes that the elimination of expedited standards development process is being done in conjunction with the addition of Section 16 that provides for waiver authority. While the expedited process has its complications, NRECA believes it would

Organization	Yes or No	Question 6 Comment
(NRECA)		troublesome to eliminate this section from an optics point of view. NRECA requests that the expedited process be revised to address the existing problems and eliminate, or significantly limit the provision of the proposed overly broad waiver section. Having a formal expedited process shows FERC and Congress we are prepared to move very quickly if needed and that we have a formal process to that clearly demonstrates how such work can be completed.NRECA continues to have significant concerns with the proposed overly broad waiver section. If the expedited process section is maintained (and improved upon to address current problems) then this overly broad waiver provision should not be needed. There has been no other demonstration of need for such a broad waiver provision. NRECA requests the waiver provision be deleted or revised to significantly limit the situations when it can be used.

Response: Thank you for your comments. NERC, the Regional Entities and industry stakeholders have a significant mutual investment in developing a sustainable Reliability Standards program that will maintain the reliability of the bulk power system in North America. The success of the unique Electric Reliability Organization (ERO) model requires NERC to develop and maintain a body of high-quality, effective Reliability Standards. The current trajectory is unsustainable and, without considering significant course correction, the ERO and industry finds itself nearing a critical juncture where alternate methods to accomplish the development of mandatory Reliability Standards has become necessary. NERC is at risk of losing the confidence of U.S. regulatory authorities and industry executives in its ability to produce standards in a timely and efficient manner.

The waiver provision is intended as a tool to allow the Standards Committee to manage the standards development process. The Standards Committee is tasked with protecting the "credibility and integrity of the standards development process." See Standards Committee Charter, available here: http://www.nerc.com/files/SC_Charter_clean_for_BOT_approval_20110417.pdf.

Section 16.0 is not a "full waiver provision" and is not overly broad. The waiver provision is intended to be used under a very limited set of circumstances, for example, where it is necessary to address an urgent reliability issue. As you note, the currently-effective Standard Process Manual provides a process for the expedited development of Reliability Standards where necessary "to meet an urgent reliability issue such that there isn't time to follow all the steps in the normal Reliability Standards development process." The waiver provision replaces this section in its entirety. The need for the ability to address urgent reliability issues has been reflected in FERC's orders certifying NERC as the ERO. See for example P 253 of *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (2006) "in rare instances, the urgent action process may not be sufficiently expedited, such as if necessary to

Organization	Yes or No	Question 6 Comment
address an imminent threat to national security. We require NERC to address whether the urgent action process, or some other process, can accommodate any such rare circumstances. " **NERC is firmly committed to the consensus-based stakeholder standards development process that is set out in NERC's Rules of Procedure.**		
Trans Bay Cable LLC	No	There was not enough information on how/when this could/would be used. I see this being used for standards such as CIP V5 that do not pass the voting process and are "pushed through" to meet FERC deadlines. More information on when this would be used and what controls would be in place are needed.
Response: Thank you for your comments. Section 16.0 is intended to provide clarity to the Standards Committee's authority to waive provisions of the Standard Processes Manual and limits the circumstances under which the Standards Committee can take such actions. Section 16.0 states that the waiver provision cannot be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard. NERC is firmly committed to the consensus-based stakeholder standards development process that is set out in NERC's Rules of Procedure. **In order to address your concern regarding what controls are in place, additional language has been added to require reporting of the use of the waiver provision to the Standards Oversight & Technology Committee.** **In response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.** **Section 8.0 of the Standard Processes Manual provides: "Any entity that has directly and materially affected interests and that has been or will be adversely affected by any procedural action or inaction related to the development, approval, revision, reaffirmation, retirement or withdrawal of a Reliability Standard, definition, Variance, associated implementation plan, or Interpretation shall have the right to appeal."**		
Public Service Enterprise	No	First, the use of a waiver will result is a violation of the NERC's American National

Organization	Yes or No	Question 6 Comment
Group		Standards Institute (ANSI)-approved standards development process; otherwise, section 16.0 would not contain the sentence "Reliability Standards developed as a result of a waiver of any provision of the Standard Processes Manual shall not be filed with ANSI for approval as American National Standards."Second, reporting the use of a waiver prior to the Board of Trustees (BOT) adopting a standard is unacceptable - see the sentence "The Standards Committee shall report the exercise of this waiver provision to the Board of Trustees prior to adoption of the related Reliability Standard, Interpretation, definition or Variance." The exercise of the waiver and BOT approval may be separated by years of work by the both the Standards Committee (SC) and the standards drafting team (SDT). Each exercise of an SC waiver should have BOT finality so that the BOT will not be pressured to approve any waiver, regardless of the facts, in order to not reject the substantial body of work that has followed the exercise of the waiver by the SC. As we suggested in our prior comments, at a minimum, waivers to the SPM should be preceded by the following:a. The posting of an SC document to the RBB that describes the reason for the requested waiver, including the threat to reliability, and what processes would be affected by the waiver.b. A short (10 day) period for accepting RBB comments.c. After comments are received, the SC may either withdraw the waiver or request its expedited approval by the NERC board, ensuring that the board is supplied with the comments received.This entire process proposed above could be completed within 30-45 days, causing a minor delay for the hopefully rare exercise by the SC of waiving an SPM provision.If this provision is adopted in the next SPM version, we will vote "Affirmative."
Response: The waiver provision would not violate ANSI. The currently-effective Standard Process Manual already provides a process for the expedited development of Reliability Standards where necessary "to meet an urgent reliability issue such that there isn't time to follow all the steps in the normal Reliability Standards development process." The waiver provision replaces this section in its entirety. **In the currently-effective Standard Process Manual, the section on Processes for Developing a Reliability Standard Related to a Confidential Issue states: "When faced with a national security emergency situation, NERC may use one of the following special**		

Organization	Yes or No	Question 6 Comment
		processes to develop a Reliability Standard that addresses an issue that is confidential. Reliability Standards developed using one of the following processes shall be called, "special Reliability Standards" and shall not be filed with ANSI for approval as ANSI standards." (emphasis added). The concept that certain Reliability Standards will not be filed with ANSI is not a new one to the Standard Processes Manual nor does it jeopardize NERC's accreditation. **In order to address your concern regarding notice to stakeholders, the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee has been incorporated. We have clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.** **NERC, the Regional Entities and industry stakeholders have a significant mutual investment in developing a sustainable Reliability Standards program that will maintain the reliability of the bulk power system in North America. The success of the unique Electric Reliability Organization (ERO) model requires NERC to develop and maintain a body of high-quality, effective Reliability Standards. The current trajectory is unsustainable and, without considering significant course correction, the ERO and industry finds itself nearing a critical juncture where alternate methods to accomplish the development of mandatory Reliability Standards has become necessary. NERC is at risk of losing the confidence of U.S. regulatory authorities and industry executives in its ability to produce standards in a timely and efficient manner.** **Adding an additional 30-45 days to the standard development process in order to utilize a waiver as proposed would defeat the very purpose of the waiver provision, which is to add flexibility to the process.** **Section 8.0 of the Standard Processes Manual provides the right of appeal: "Any entity that has directly and materially affected interests and that has been or will be adversely affected by any procedural action or inaction related to the development, approval, revision, reaffirmation, retirement or withdrawal of a Reliability Standard, definition, Variance, associated implementation plan, or Interpretation shall have the right to appeal." Any entity would have the right to appeal the use of the waiver provision at the time that the waiver is approved by the Standards Committee or when public notice of intent to use waiver is issued.**
Owensboro Municipal Utilities	No	OMU is not opposed to a fast track process utilizing specific guidelines or criteria ;however, we cannot support a full waiver provision with the SC.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comments. Section 16.0 is not a "full waiver provision." The waiver provision is intended to be used under a very limited set of circumstances, for example, where it is necessary to address an urgent reliability issue. The currently-effective Standard Process Manual provides a process for the expedited development of Reliability Standards where necessary "to meet an urgent reliability issue such that there isn't time to follow all the steps in the normal Reliability Standards development process." The waiver provision replaces this section in its entirety. The need for the ability to address urgent reliability issues has been reflected in FERC's orders certifying NERC as the ERO. See for example P 253 of *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (2006) "in rare instances, the urgent action process may not be sufficiently expedited, such as if necessary to address an imminent threat to national security. We require NERC to address whether the urgent action process, or some other process, can accommodate any such rare circumstances. " **Section 16.0 is intended to provide clarity to the Standards Committee's authority to waive provisions of the Standard Processes Manual and limits the circumstances under which the Standards Committee can take such actions. In addition, Section 16.0 states that the waiver provision cannot be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard.**		
Duke Energy	No	The circumstances listed in Section 16 for invoking the waiver provision do not constitute reliability needs. The provisions that can be waived should be more limited and the circumstances for which they can be waived should be based on clearly articulated reliability needs. The industry expertise of the Members Representative Committee (MRC) should be used to evaluate the provisions being waived and the circumstances they are being waived in.
Response: Thank you for your comments. NERC, the Regional Entities and industry stakeholders have a significant mutual investment in developing a sustainable Reliability Standards program that will maintain the reliability of the bulk power system in North America. The success of the unique Electric Reliability Organization (ERO) model requires NERC to develop and maintain a body of high-quality, effective Reliability Standards. The current trajectory is unsustainable and, without considering significant course correction, the ERO and industry finds itself nearing a critical juncture where alternate methods to accomplish the development of mandatory Reliability Standards has become necessary. NERC is at risk of losing the confidence of U.S. regulatory authorities and industry executives in its ability to produce standards in a timely and efficient manner.		

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Respectfully, we suggest that in order for the ERO model to be successful, NERC must have the ability to meet regulatory deadlines. Pursuant to section 215(d)(5) of the FPA, the Commission may direct the ERO to submit to the Commission a new or modified Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Standard appropriate to carry out section 215. As the ERO, NERC must be able to comply with a Commission directive pursuant to section 215(d)(5) of the FPA. **The need for the ability to address urgent reliability issues has been reflected in FERC's orders certifying NERC as the ERO. See for example P 253 of *North American Electric Reliability Corp*., 116 FERC ¶ 61,062 (2006) "in rare instances, the urgent action process may not be sufficiently expedited, such as if necessary to address an imminent threat to national security. We require NERC to address whether the urgent action process, or some other process, can accommodate any such rare circumstances. "** **There is a direct relationship between reliability of the grid and the need for the ability to take action on Reliability Standards in a timely manner.** **In response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.**		
American Electric Power	No	Though AEP would not object outright to such a waiver process, our concerns would be in regards to what level of perceived urgency might drive such a waiver, as well as how often such a waiver might be invoked. Such a waiver should only be used for the most extreme and rare circumstances, and the circumstances as currently listed are not restrictive enough. For example, "where necessary to meet regulatory deadlines" is entirely subjective and could conceivably be used for almost any circumstance. Rather than being so open-ended, AEP recommends adding language stating that invoking such a waiver could *only* be done in response to circumstances involving a known and immediate impact to the reliability of the BES. In addition, and perhaps more importantly, it would appear that any such waiver process would be in direct violation of ANSI standards. NERC seems to acknowledge this at least in part by

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		stating in the SPM that "Reliability Standards developed as a result of a waiver of any provision of the Standard Processes Manual shall not be filed with ANSI for approval as American National Standards." AEP is greatly concerned by any process which would circumvent ANSI for any reason, even for expediency's sake, and seeks clarification on what ANSI accreditation implications there might for NERC as a result of the proposed process.

Response: Thank you for your comments. The waiver provision would not violate ANSI. The currently-effective Standard Process Manual already provides a process for the expedited development of Reliability Standards where necessary "to meet an urgent reliability issue such that there isn't time to follow all the steps in the normal Reliability Standards development process." The waiver provision replaces this section in its entirety.

In the currently-effective Standard Process Manual, the section on Processes for Developing a Reliability Standard Related to a Confidential Issue states: "When faced with a national security emergency situation, NERC may use one of the following special processes to develop a Reliability Standard that addresses an issue that is confidential. Reliability Standards developed using one of the following processes shall be called, "special Reliability Standards" and shall not be filed with ANSI for approval as ANSI standards." (emphasis added). The concept that certain Reliability Standards will not be filed with ANSI is not a new one to the Standard Processes Manual nor does it jeopardize NERC's accreditation.

NERC, the Regional Entities and industry stakeholders have a significant mutual investment in developing a sustainable Reliability Standards program that will maintain the reliability of the bulk power system in North America. The success of the unique Electric Reliability Organization (ERO) model requires NERC to develop and maintain a body of high-quality, effective Reliability Standards. The current trajectory is unsustainable and, without considering significant course correction, the ERO and industry finds itself nearing a critical juncture where alternate methods to accomplish the development of mandatory Reliability Standards has become necessary. NERC is at risk of losing the confidence of U.S. regulatory authorities and industry executives in its ability to produce standards in a timely and efficient manner.

Section 16.0 is intended to provide clarity to the Standards Committee's authority to waive provisions of the Standard Processes Manual and limits the circumstances under which the Standards Committee can take such actions. Section 16.0 states that the waiver provision cannot be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard. NERC is firmly committed to the consensus-based stakeholder standards development process that is set out in NERC's Rules of Procedure.

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The United Illuminating Company	No	: UI does not believe the propose waiver process will function. Without ballot body support to waive the ANSI process any attempt to utilize the waiver process will result in a negative vote. The proposed process will not expedite a standard but delay it.The proposed process informs the BOT at the time a standard is submitted for BOT approval that it was developed via a Waiver process which can lead to the inefficiency of the BOT remanding the Standard to go through the ANSI process. This would be more inefficient then just going with the ANSI process. UI proposes the inclusion of a 15 day ballot where the SC provides notice a Standard will be drafted with a waiver on certain sections of the ANSI process. The Ballot body could then approve the waiver and development could proceed.

Response: Thank you for your comments. NERC, the Regional Entities and industry stakeholders have a significant mutual investment in developing a sustainable Reliability Standards program that will maintain the reliability of the bulk power system in North America. The success of the unique Electric Reliability Organization (ERO) model requires NERC to develop and maintain a body of high-quality, effective Reliability Standards. The current trajectory is unsustainable and, without considering significant course correction, the ERO and industry finds itself nearing a critical juncture where alternate methods to accomplish the development of mandatory Reliability Standards has become necessary. NERC is at risk of losing the confidence of U.S. regulatory authorities and industry executives in its ability to produce standards in a timely and efficient manner.

Adding an additional ballot period to the standard development process in order to utilize a waiver as proposed would defeat the very purpose of the waiver provision, which is to add flexibility to the process. In response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.

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Occidental Energy Ventures Corp	No	The issue is not whether the SC applies the wavier - its whether NERC and FERC can dispense with industry-acceptance when they believe the need is urgent. OEVC understands that they may have the legal authority to do so (as defined in the FPA), but does not agree that this allows the ENTIRE process to be ANSI accredited. The ANSI process is intended to demonstrate sincere cooperative efforts between organizations that have different goals - and result in a body of standards which is accepted by all stakeholders. Simply declaring that one group is ANSI certified while the other group is not, is not acceptable to OEVC. Therefore, OEVC cannot support this recommendation.
Response: Thank you for your comment. The waiver provision does not allow the Standards Committee to dispense with industry-acceptance and in fact expressly forbids this. Section 16.0 states that the waiver provision cannot be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard. Section 16.0 is intended to provide clarity to the Standards Committee's authority to waive provisions of the Standard Processes Manual and limits the circumstances under which the Standards Committee can take such actions. NERC is firmly committed to the consensus-based stakeholder standards development process that is set out in NERC's Rules of Procedure. **The waiver provision would not violate ANSI. The currently-effective Standard Process Manual already provides a process for the**		

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NIPSCO	No	There appears to be concern in the industry regarding this waiver section 16.
Response: Thank you for your comment. NERC, the Regional Entities and industry stakeholders have a significant mutual investment in developing a sustainable Reliability Standards program that will maintain the reliability of the bulk power system in North America. The success of the unique Electric Reliability Organization (ERO) model requires NERC to develop and maintain a body of high-quality, effective Reliability Standards. The current trajectory is unsustainable and, without considering significant course correction, the ERO and industry finds itself nearing a critical juncture where alternate methods to accomplish the development of mandatory Reliability Standards has become necessary. NERC is at risk of losing the confidence of U.S. regulatory authorities and industry executives in its ability to produce standards in a timely and efficient manner. The waiver provision is intended as a tool to allow the Standards Committee to manage the standards development process. The Standards Committee is tasked with protecting the "credibility and integrity of the standards development process." See Standards Committee Charter, available here: http://www.nerc.com/files/SC_Charter_clean_for_BOT_approval_20110417.pdf.		

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In response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.		
Manitoba Hydro	No	Section 16.0 proposes to allow NERC's Standards Committee to "waive" any provisions in the manual for good cause shown under certain circumstances: (1. to meet NERC BOT deadlines; 2. to meet regulatory deadlines; 3. for "insubstantial" modifications to standards). Our first concern is that the concept of a "waiver" is inappropriate in this context. In legal terms, a party can only waive its own rights, not its obligations or the rights of others. The NERC membership, not the Standards Committee, has the right to insist that all standards be developed in accordance with the NERC Rules of Procedure (as part of the membership agreement), including the SPM which forms part of the ROP. Accordingly, only the NERC membership as a whole can waive this right. The Standards Committee cannot "waive" its obligation to follow the SPM.Furthermore, the Standards Development Process is a core principle of NERC that ensures that industry has sufficient input into the development of a standard. This core principle served as the primary foundation for various Canadian Governmental Authorities granting authority to NERC. Eliminating or shortening comment periods through a generic waiver provision can significantly erode industry involvement, especially considering the volume of standards development projects which compete for attention. This can cause Canadian Governmental Authorities to reconsider NERC's authority in the various provinces. In Manitoba, only NERC Rules of Procedure that are incorporated into regulation will be effective in Manitoba. It is to be noted that the provisions of Section 321 of the NERC ROP governing responding to regulatory directives also attempted to make deviations from the standards development process and was intensely debated by industry, including the Canadian Electricity Association. The proposed waiver criterion regarding "meeting NERC BOT deadlines" allows considerable discretion to the board which could trigger the waiver

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		provisions, and provides too much uncertainty.
Response: Thank you for your comments. **If the waiver provision is incorporated into the Standard Processes Manual then the exercise of the waiver provision would be consistent with the Standard Processes Manual, therefore, there would be no applicable waiver of any party's rights or obligations.** **NERC, the Regional Entities and industry stakeholders have a significant mutual investment in developing a sustainable Reliability Standards program that will maintain the reliability of the bulk power system in North America. The success of the unique Electric Reliability Organization (ERO) model requires NERC to develop and maintain a body of high-quality, effective Reliability Standards. The current trajectory is unsustainable and, without considering significant course correction, the ERO and industry finds itself nearing a critical juncture where alternate methods to accomplish the development of mandatory Reliability Standards has become necessary. NERC is at risk of losing the confidence of U.S. and Canadian regulatory authorities and industry executives in its ability to produce standards in a timely and efficient manner.** **The waiver provision is intended as a tool to allow the Standards Committee to manage the standards development process. The Standards Committee is tasked with protecting the "credibility and integrity of the standards development process." See Standards Committee Charter, available here: http://www.nerc.com/files/SC_Charter_clean_for_BOT_approval_20110417.pdf.** **In response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.**		
CenterPoint Energy Houston Electric L.L.C.	No	CenterPoint Energy does not believe such a waiver is necessary. The circumstances listed do not rise to this level of urgency. FERC and the NERC BOT are well aware of the minimum time needed to develop and ballot a new or revised Standard. The Company does not believe there are actual reliability issues that would be so critical as to require such an expedited process. If one did arise, there are other means available to address such a concern such as the NERC Alert process.

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Response: Thank you for your comments. Beginning in Order No. 672 (at P 269), the Commission has expressed concern regarding the amount of time it takes to develop an ANSI standard. "We are concerned about the time it may take to develop a Reliability Standard under the ANSI-certified process. The ERO applicant should address in its application the timetable for developing a proposed Reliability Standard under an ANSI-certified or other process, including the timetable for developing a proposed Reliability Standard that is urgently needed. Moreover, the ERO applicant should also propose a process for modifying or replacing a Reliability Standard (even if interim in nature) in the event that the Commission orders the ERO to modify a Reliability Standard." **The Commission has continuously directed NERC to modify its Standard Development Process to ensure that the ERO is able to respond to urgent reliability issues. See for example P 253 of *North American Electric Reliability Corp*., 116 FERC ¶ 61,062 (2006) "in rare instances, the urgent action process may not be sufficiently expedited, such as if necessary to address an imminent threat to national security. We require NERC to address whether the urgent action process, or some other process, can accommodate any such rare circumstances. "** **There is a direct relationship between reliability of the grid and the need for the ability to take action on Reliability Standards in a timely manner.**		
Ameren	No	The waiver provision is not necessary because the NERC Rules of Procedure already has a process for this scenario. (2) It seems to us that the revision now have the BOT and stakeholders' involvement at the end of the process rather than at the beginning. We believe that the approval for the use of the waiver process for a specific reason should get necessary approval (buy-in) from stakeholders and BOT before SC starts using the process to revise or develop a new standard. (3) Has the SDT confirmed that the waiver proposal would be within the ANSI process?
Response: Thank you for your comments. **The waiver provision would not violate ANSI. The currently-effective Standard Process Manual already provides a process for the expedited development of Reliability Standards where necessary "to meet an urgent reliability issue such that there isn't time to follow all the steps in the normal Reliability Standards development process." The waiver provision replaces this section in its entirety.** **In the currently-effective Standard Process Manual, the section on Processes for Developing a Reliability Standard Related to a**		

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Tri-State G & T	No	The use of a waiver will result in a violation of the NERC's ANSI approved standards development process and eliminates the full participation of the industry in standard development. The expedited standards development process should be revised to address the concerns, or alternative methods should be considered such that the industry is still allowed to participate in the standard development process and expedited requirements, when needed.
Response: Thank you for your comment. The waiver provision would not violate ANSI. As you note, the currently-effective Standard Process Manual already provides a process for the expedited development of Reliability Standards where necessary "to meet an urgent reliability issue such that there isn't time to follow all the steps in the normal Reliability Standards development process." The waiver provision replaces this section in its entirety. The need for the ability to address urgent reliability issues has been reflected in FERC's orders certifying NERC as the ERO. See for example P 253 of *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (2006) "in rare instances, the urgent action process may not be sufficiently expedited, such as if necessary to address an imminent threat to national security. We require NERC to address whether the urgent action process, or some other process, can accommodate any such rare circumstances. " **In the currently-effective Standard Process Manual, the section on Processes for Developing a Reliability Standard Related to a Confidential Issue states: "When faced with a national security emergency situation, NERC may use one of the following special processes to develop a Reliability Standard that addresses an issue that is confidential. Reliability Standards developed using one**		

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Oklahoma Gas & Electric	No	We do not support Section 16.0 which provides a waiver to allow for a revision of a Standard, definition, Variance, or implementation plan to meet an urgent reliability issue. The circumstances in which this waiver would be allowed are outlined as (1) meet regulatory deadlines, (2) meet deadlines imposed by the NERC BOT, or (3) SC determine the modification has already been vetted. These circumstances do not seem to meet the initial statement of "to meet an urgent reliability issue". We do not consider regulatory deadlines to be urgent reliability issues.
Response: Thank you for your comments. Respectfully, we suggest that in order for the ERO model to be successful, NERC must have the ability to meet regulatory deadlines. **Pursuant to section 215(d)(5) of the FPA, the Commission may direct the ERO to submit to the Commission a new or modified Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Standard appropriate to carry out section 215. As the ERO, NERC must be able to comply with a Commission directive pursuant to section 215(d)(5) of the FPA. The Commission has expressed concern that the standard development process can be misused to "delay or block NERC's ability to report to a Commission directive" *See North American Electric Reliability Corp.*, 130 FERC ¶ 61,203 at P 23 (2010).** **Section 16.0 is intended to provide clarity to the Standards Committee's authority to waive provisions of the Standard Processes Manual and limits the circumstances under which the Standards Committee can take such actions. In addition, Section 16.0 states that the waiver provision cannot be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard. NERC is firmly committed to the consensus-based stakeholder standards development process that is set out in NERC's Rules of Procedure.**		

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Independent Electricity System Operator	No	We do support the addition of the Waiver section, recognizing that this particular section proposes a provision to cover only urgent reliability standard revisions, and not emergency situations requiring immediate action. We believe clear distinction and separation, possibly supported by separate processes, should be made between an urgent situation requiring an urgent standard development and an emergency situation requiring an immediate action. An emergency reliability standard revision procedural step would give the NERC Board the authority to act on its own motion to address an issue on an interim basis immediately, with a follow-on process to then review and address the issue on a more regular timetable.However, all standard /definition/variance/implementation plans approved under such a fast track process must be subjected to peer review and balloting for it to become an enduring part of the NERC standards/definitions/etc.

Response: Thank you for your comments. NERC, the Regional Entities and industry stakeholders have a significant mutual investment in developing a sustainable Reliability Standards program that will maintain the reliability of the bulk power system in North America. The success of the unique Electric Reliability Organization (ERO) model requires NERC to develop and maintain a body of high-quality, effective Reliability Standards. The current trajectory is unsustainable and, without considering significant course correction, the ERO and industry finds itself nearing a critical juncture where alternate methods to accomplish the development of mandatory Reliability Standards has become necessary. NERC is at risk of losing the confidence of U.S. and Canadian regulatory authorities and industry executives in its ability to produce standards in a timely and efficient manner.

The currently-effective Standard Process Manual provides a process for the expedited development of Reliability Standards where necessary "to meet an urgent reliability issue such that there isn't time to follow all the steps in the normal Reliability Standards development process." The waiver provision replaces this section in its entirety. The need for the ability to address urgent reliability issues has been reflected in FERC's orders certifying NERC as the ERO. See for example P 253 of *North American Electric Reliability Corp*., 116 FERC ¶ 61,062 (2006) "in rare instances, the urgent action process may not be sufficiently expedited, such as if necessary to address an imminent threat to national security. We require NERC to address whether the urgent action process, or some other process, can accommodate any such rare circumstances. "

There is a direct relationship between reliability of the grid and the need for the ability to take action on Reliability Standards in a timely manner.

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South Carolina Electric and Gas	No	The current expedited standards development process should be retained. The use of waivers is not consistent with the ANSI process and should be rejected. The use of a waiver will result is a violation of the NERC's American National Standards Institute (ANSI)-approved standards development process. Reporting the use of a waiver prior to the Board of Trustees (BOT) adopting a standard is unacceptable. The exercise of the waiver and BOT approval may be separated by years of work by the both the Standards Committee (SC) and the standards drafting team (SDT). Each exercise of an SC waiver should have BOT finality so that the BOT will not be pressured to approve any waiver, regardless of the facts, in order to not reject the substantial body of work that has followed the exercise of the waiver by the SC. At a minimum, waivers to the SPM should be preceded by the following: a. The posting of an SC document to the RBB that describes the reason for the requested waiver, including the threat to reliability, and what processes would be affected by the waiver. b. A short (10 day) period for accepting RBB comments. c. After comments are received, the SC may either withdraw the waiver or request its expedited approval by the NERC board, ensuring that the board is supplied with the comments received. This entire process proposed above could be completed within 30-45 days, causing a minor delay for the hopefully rare exercise by the SC of waiving an SPM provision.The present SPM has an "expedited standards development process" that was stricken. However, the ROP section 300 (Reliability Standards Development) requires that process. The SPM should retain that; without it in the SPM, NERC cannot respond to a request from a governmental authority for expedited development of a standard. The SPM therefore needs to retain that procedure, unless the SPM procedure is waived, which is the next topic. If this provision were reinstated, the use of a waiver process would be minimized since the expedited process would be a provision of the SPM.
Response: Thank you for your comments. The waiver provision would not violate ANSI. As you note, the currently-effective Standard Process Manual already provides a process for the expedited development of Reliability Standards where necessary "to meet an urgent reliability issue such that there isn't time to follow all the steps in the normal Reliability Standards development process." The waiver provision replaces this section in its entirety. The need for the ability to address urgent reliability issues has		

Organization	Yes or No	Question 6 Comment
		been reflected in FERC's orders certifying NERC as the ERO. See for example P 253 of *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (2006) "in rare instances, the urgent action process may not be sufficiently expedited, such as if necessary to address an imminent threat to national security. We require NERC to address whether the urgent action process, or some other process, can accommodate any such rare circumstances. " In the currently-effective Standard Process Manual, the section on Processes for Developing a Reliability Standard Related to a Confidential Issue states: "When faced with a national security emergency situation, NERC may use one of the following special processes to develop a Reliability Standard that addresses an issue that is confidential. Reliability Standards developed using one of the following processes shall be called, "special Reliability Standards" and shall not be filed with ANSI for approval as ANSI standards." (emphasis added). The concept that certain Reliability Standards will not be filed with ANSI is not a new one to the Standard Processes Manual nor does it jeopardize NERC's accreditation. A Standard developed using the Expedited Reliability Standard Development Process is approved only on a conditional basis and it must *again* go through the standard development process in order to be made permanent. The Expedited Reliability Standard Development Process provides: If a new or modified Reliability Standard is developed, approved by its ballot pool, and subsequently adopted by the NERC Board of Trustees through this expedited process, one of the following three actions shall occur [fn27]: • If the Reliability Standard is to be made permanent without additional substantive changes, then a SAR and a proposed Reliability Standard shall be submitted to the Reliability Standards staff immediately after the ballot. The project shall be added to the list of approved projects and shall proceed through the regular standard development process, including balloting by stakeholders, without any intentional delay. • If the Reliability Standard is to be substantively revised or replaced by a new Reliability Standard, then a project for the new or revised Reliability Standard shall be added to the list of projects to be added to the Reliability Standard Development Plan. The project shall be initiated as soon as practical after the ballot and the project shall proceed through the regular Reliability Standard development process, including balloting by stakeholders, as soon as practical but within two years of the date the Reliability Standard was approved by stakeholders using the expedited process. • The Reliability Standard shall be withdrawn through a ballot of the stakeholders within two years of the date the Reliability Standard was approved by stakeholders using the expedited process. Rather than repeating the standard development process, Section 16.0 would allow a Reliability Standard to become "permanent"

Organization	Yes or No	Question 6 Comment
upon stakeholder approval. **In response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.**		
SCE&G	No	The current expedited standards development process should be retained. The use of waivers is not consistent with the ANSI process and should be rejected. The use of a waiver will result is a violation of the NERC's American National Standards Institute (ANSI)-approved standards development process. Reporting the use of a waiver prior to the Board of Trustees (BOT) adopting a standard is unacceptable. The exercise of the waiver and BOT approval may be separated by years of work by the both the Standards Committee (SC) and the standards drafting team (SDT). Each exercise of an SC waiver should have BOT finality so that the BOT will not be pressured to approve any waiver, regardless of the facts, in order to not reject the substantial body of work that has followed the exercise of the waiver by the SC. At a minimum, waivers to the SPM should be preceded by the following: a. The posting of an SC document to the RBB that describes the reason for the requested waiver, including the threat to reliability, and what processes would be affected by the waiver. b. A short (10 day) period for accepting RBB comments. c. After comments are received, the SC may either withdraw the waiver or request its expedited approval by the NERC board, ensuring that the board is supplied with the comments received. This entire process proposed above could be completed within 30-45 days, causing a minor delay for the hopefully rare exercise by the SC of waiving an SPM provision.3) The present SPM has an "expedited standards development process" that was stricken. However, the ROP section 300 (Reliability Standards Development) requires that process. The SPM should retain that; without it in the SPM, NERC cannot respond to a request from a governmental authority for expedited development of a standard. The SPM therefore

Organization	Yes or No	Question 6 Comment
		needs to retain that procedure, unless the SPM procedure is waived, which is the next topic. If this provision were reinstated, the use of a waiver process would be minimized since the expedited process would be a provision of the SPM.

Response: Thank you for your comments. The waiver provision would not violate ANSI. As you note, the currently-effective Standard Process Manual already provides a process for the expedited development of Reliability Standards where necessary "to meet an urgent reliability issue such that there isn't time to follow all the steps in the normal Reliability Standards development process." The waiver provision replaces this section in its entirety. The need for the ability to address urgent reliability issues has been reflected in FERC's orders certifying NERC as the ERO. See for example P 253 of *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (2006) "in rare instances, the urgent action process may not be sufficiently expedited, such as if necessary to address an imminent threat to national security. We require NERC to address whether the urgent action process, or some other process, can accommodate any such rare circumstances. "

In the currently-effective Standard Process Manual, the section on Processes for Developing a Reliability Standard Related to a Confidential Issue states: "When faced with a national security emergency situation, NERC may use one of the following special processes to develop a Reliability Standard that addresses an issue that is confidential. Reliability Standards developed using one of the following processes shall be called, "special Reliability Standards" and shall not be filed with ANSI for approval as ANSI standards." (emphasis added). The concept that certain Reliability Standards will not be filed with ANSI is not a new one to the Standard Processes Manual nor does it jeopardize NERC's accreditation.

A Standard developed using the Expedited Reliability Standard Development Process is approved only on a conditional basis and it must *again* go through the standard development process in order to be made permanent. The Expedited Reliability Standard Development Process provides:

If a new or modified Reliability Standard is developed, approved by its ballot pool, and subsequently adopted by the NERC Board of Trustees through this expedited process, one of the following three actions shall occur [fn27]:

• If the Reliability Standard is to be made permanent without additional substantive changes, then a SAR and a proposed Reliability Standard shall be submitted to the Reliability Standards staff immediately after the ballot. The project shall be added to the list of approved projects and shall proceed through the regular standard development process, including balloting by stakeholders, without any intentional delay.

• If the Reliability Standard is to be substantively revised or replaced by a new Reliability Standard, then a project for the new or revised Reliability Standard shall be added to the list of projects to be added to the Reliability Standard Development Plan. The

Organization	Yes or No	Question 6 Comment
project shall be initiated as soon as practical after the ballot and the project shall proceed through the regular Reliability Standard development process, including balloting by stakeholders, as soon as practical but within two years of the date the Reliability Standard was approved by stakeholders using the expedited process. **• The Reliability Standard shall be withdrawn through a ballot of the stakeholders within two years of the date the Reliability Standard was approved by stakeholders using the expedited process.** **Rather than repeating the standard development process, Section 16.0 would allow a Reliability Standard to become "permanent" upon stakeholder approval.** **In response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.**		
Trans Bay Cable LLC	No	There is not enough checks and balances in the current proposed changes to ensure that the SC will not abuse this ability.
Response: Thank you for your comments. The Standards Committee is tasked with protecting the "credibility and integrity of the standards development process." *See* Standards Committee Charter, available here: http://www.nerc.com/files/SC_Charter_clean_for_BOT_approval_20110417.pdf. **As an additional check on the authority of the Standards Committee, a provision has been added to report the use of the waiver provision to the Standards Oversight and Technology Committee.**		
HHWP	No	I agree with the comments and the alternative waiver proposal made by PSEG.
Response: Thank you for your comments. Please see response to comments of PSEG.		
Tacoma Power	No	Tacoma Power cannot support the addition of the waiver provision in Section 16.0 with the additional clarification. Tacoma Power believes the waiver provisions of

Organization	Yes or No	Question 6 Comment
		Section 16.0 are overly broad and opaque. Section 16.0 provides the Standards Committee an option to bypass the standard development process. Tacoma Power is concerned that the waiver provision would be too easy to resort to under pressure from various deadlines. Such a waiver option should be, at minimum, mitigated with counteracting safeguards and procedural steps and only available in situations recognized as necessary to prevent an imminent threat to reliability to guard against potential misuse. The comment form's explanation implies that the BOT review will provide an overview and gate-keeping safeguard to waivers. However, Section 16.0 only states that the SC will report the exercise of the waiver provision to the BOT prior to adoption. What the BOT's review process will be, the considerations it will use, and what detail is required in the report to the BOT is not specified. At minimum, Tacoma Power believes there should be a more formal process established for waiver approval (such as by the BOT). A public posting for a short period could be required to receive comments before waiver. The posting could describe the reason and identify the specific processes that will be changed by the waiver. Therefore, Tacoma Power believes Section 16.0 should be removed until an open and sufficient waiver process can be developed.
Response: Thank you for your comments. In response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.		
Oncor Electric Delivery	No	Oncor is not in agreement with proposed Waiver as prescribed in Section 16. The current Rule of Procedure (Section 309.3) requires an "expedited standards development process" for the Standard Process Manual. The proposed changes to the SPM strike this provision (Section 9, 10 - Redline Version). Without this provision, NERC cannot respond to a request from a governmental authority for expedited

Organization	Yes or No	Question 6 Comment
		development of a standard. Furthermore, the proposed Waiver has no appeals process, thus granting the Standards Committee the power to authorize change to NERC Reliability Standards – unchecked. Oncor takes the position that the existing "expedited standards development process" for the Standard Process Manual is adequate and sufficient and that the proposed Waiver as prescribed in section 16.0 be removed

Response: Thank you for your comments. As you note, Section 16.0 is very similar to the currently –effective Standard Processes Manual section of the Expedited Reliability Standard Development Process. However, a Standard developed using the Expedited Reliability Standard Development Process is approved only on a conditional basis and it must *again* go through the standard development process in order to be made permanent. The Expedited Reliability Standard Development Process provides:

If a new or modified Reliability Standard is developed, approved by its ballot pool, and subsequently adopted by the NERC Board of Trustees through this expedited process, one of the following three actions shall occur [fn27]:

• If the Reliability Standard is to be made permanent without additional substantive changes, then a SAR and a proposed Reliability Standard shall be submitted to the Reliability Standards staff immediately after the ballot. The project shall be added to the list of approved projects and shall proceed through the regular standard development process, including balloting by stakeholders, without any intentional delay.

• If the Reliability Standard is to be substantively revised or replaced by a new Reliability Standard, then a project for the new or revised Reliability Standard shall be added to the list of projects to be added to the Reliability Standard Development Plan. The project shall be initiated as soon as practical after the ballot and the project shall proceed through the regular Reliability Standard development process, including balloting by stakeholders, as soon as practical but within two years of the date the Reliability Standard was approved by stakeholders using the expedited process.

• The Reliability Standard shall be withdrawn through a ballot of the stakeholders within two years of the date the Reliability Standard was approved by stakeholders using the expedited process.

This is clearly redundant and a waste of resources for NERC, the industry and the drafting team. Rather than repeating the standard development process, Section 16.0 would allow a Reliability Standard to become "permanent" upon stakeholder approval.

In response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the

Organization	Yes or No	Question 6 Comment
concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.		
CPS Energy	No	
Kansas City Power & Light	No	
FirstEnergy	Yes	FE supports the addition of Section 16.0, however, the phrase in the third bullet that begins with "or is so insubstantial" is confusing. Is this referring to an errata change only? Or is it referring to a 'rapid fix'? this should be more clearly defined.
Response: Thank you for your comments. The third bullet is intended to refer to circumstances where the process should be waived to provide flexibility. For example, a commenter may propose alternative language in a requirement that is superior to the drafting team's proposal. An abbreviated comment period may be sufficient to reach consensus on this substantive change.		
JEA	Yes	JEA is supporting the waiver provision with the understanding that the balloting, quorum and approval requirements in the manual cannot be waived. Further, JEA suggests the language related to the waiver be changed to more clearly reflect this. For example, the second paragraph of 16.0 could be changed to say "...may waive any of the provisions in this manual except the balloting and the quorum provisions..."
Response: Thank you for your comments and for your support. You are correct that approval still requires a 75% quorum, a two-thirds segment weighted supermajority approval, and responses to all comments raised, plus a final/recirculation ballot. Section 16.0 states that the waiver provision cannot be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard. NERC is firmly committed to the consensus-based stakeholder standards development process that is set out in NERC's Rules of Procedure.		
Bonneville Power	Yes	BPA appreciates the opportunity to comment on the Standards Process Manual. BPA

Organization	Yes or No	Question 6 Comment
Administration		would like to acknowledge the Standards Committee willingness to work with the industry on revising the Standards Process Manual (SPM) and appreciates that most of BPA's previous comments have been addressed in the latest draft. While BPA is voting yes on the current SPM version, BPA strongly encourages the SC to consider modification of the current section 16 to address industry concerns. By modifying section 16 to address industry concerns BPA believes the gesture will increase industry confidence in the SC and will ease the transition of the implementation of the new SPM.Section 16 "Waiver" of the Standards Process Manual:BPA has concerns about Section 16, BPA understands the need to have the flexibility of a waiver. BPA is unaware of any specific examples for the need of such a broad waiver. BPA would like to recommend one of two options:1. Revise the Waiver section to increase industry awareness and knowledge of the proposed waiver to include:a. A short posting (10 days) of the need for the waiverb. a short (10 days) opportunity for the industry to comment. If the majority of industry stakeholders express a concern, then the final decision should be evaluated to the BOTc. a single concise response from the SC on the decision to continue with the proposed waiver or to withdraw2. Revising the current expedited process section to address current issues the SPIG, the NERC SC and NERC staff.

Response: Thank you for your comments and for your support. Modifications have been made to Section 16 to address industry concerns. Specifically, in response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.

Revising the expedited process section of the Standard Processes Manual is ineffective because the Expedited Process requires that as soon as the standard is adopted by the Board NERC must either announce that the standard will expire after two years or repeat the entire standards process again to develop and approve the same standard or a modified standard. This is clearly redundant and a waste of resources for NERC, the industry and the drafting team.

Organization	Yes or No	Question 6 Comment
Southern Company	Yes	Southern Company raises the following concerns with deletion of the Expedited Standards Development Process and inclusion of a Waiver Provision:The proposed SPM revisions do not recognize a threshold distinction between 'elimination of a provision' and 'modification of a provision.' The currently effective SPM includes a provision for an expedited process which essentially gives the Standards Committee the authority to adjust (modify) the timeframes of certain steps within the regular standards development process. The proposed revisions (Section 16) allow the Standards Committee to waive (eliminate) any provision within the SPM for good cause shown and within certain limited circumstances. The waiver provision could be broadly interpreted to mean that the Standards Committee could not only shorten a timeframe within a step, but it could completely ignore any step or other action as a means to achieve certain objectives. As a threshold matter, the Standards Committee should restore the explicit provisions under the current expedited process. Where the Standards Committee seeks broader authority to address any other provision within the SPM, it should specify which provisions it would reasonably anticipate as requiring some type of modification and then codify how it would exercise its authority in that regard. The draft SPM expands the Standards Committee's authority. Rules of Procedure Section 321, Special Rule to Address Certain Regulatory Directives, establish which actions the BOT may take to develop standards where the rule applies. The rule does not give explicit authority to the Standards Committee to waive or eliminate steps as explained in the draft waiver provision. For the most part, the rule establishes the BOT authority for certain circumstances and describes how the BOT can be assisted by the Standards Committee, NERC Staff, stakeholders and the public at large.The draft SPM waiver section describes how the Standards Committee shall report its use of the waiver provision to the BOT prior to adoption of a Reliability Standard, Interpretation, definition or Variance. This is a key aspect which demonstrates that procedures and controls are in place to ensure some level of transparency. However, it is not clear that the Standards Committee does not need or require explicit instruction from the BOT before proceeding with a waiver. The basis

Organization	Yes or No	Question 6 Comment
		for this requirement may be rooted in whether or not the Standards Committee is deriving its waiver authority from rule 321. If the authority is rooted in rule 321, then according to the rule, at each instance where a ballot fails to address a regulatory directive and the BOT decides to exercise its authority, prior to remanding a proposed Reliability Standard to the Standards Committee with instructions, the BOT must either (1) be presented with a proposed Reliability Standard that fails to address a directive or (2) the BOT itself must make a written finding that a ballot pool has failed to address a directive. This suggests that at some point prior to the Standards Committee taking some action (i.e. an action described within the waiver provision) based on the BOT's instructions, there must be some correspondence memorializing why the Standards Committee will take the action in the first instance. If the above argument holds, wouldn't the Standards Committee be obliged to wait for explicit instructions from the BOT prior to invoking waiver provisions in those instances where rule 321 is being invoked? If the answer is yes then the waiver provision should clarify this obligation as a procedural matter.

Response: Thank you for your comments. In response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.

The authority for the waiver provision is not rooted in Rule 321 of the NERC Rules of Procedure. Section 16.0 states that the waiver provision cannot be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard. NERC is firmly committed to the consensus-based stakeholder standards development process that is set out in NERC's Rules of Procedure.

Revising the expedited process section of the Standard Processes Manual is ineffective because the Expedited Process requires that as soon as the standard is adopted by the Board NERC must either announce that the standard will expire after two years or repeat the entire standards process again to develop and approve the same standard or a modified standard. This is clearly

Organization	Yes or No	Question 6 Comment
redundant and a waste of resources for NERC, the industry and the drafting team. The waiver provision is intended as a tool to allow the Standards Committee to manage the standards development process. The Standards Committee is tasked with protecting the "credibility and integrity of the standards development process." *See* Standards Committee Charter, available here: http://www.nerc.com/files/SC_Charter_clean_for_BOT_approval_20110417.pdf. The record of the decision on the waiver request will be documented by NERC staff and maintained on the relevant project page on the NERC website.		
Liberty Electric Power LLC	Yes	There are concerns with the inclusion of the "to meet a timeline set by the NERC BOT" as a waiver condition. The potential remains for the BOT to set deadlines without a compelling need (see COM-003).
Response: Thank you for your comments and for your support. The ERO must be able to meet the deadlines set by its Board of Trustees in order to be successful. NERC, the Regional Entities and industry stakeholders have a significant mutual investment in developing a sustainable Reliability Standards program that will maintain the reliability of the bulk power system in North America. The success of the unique Electric Reliability Organization (ERO) model requires NERC to develop and maintain a body of high-quality, effective Reliability Standards. The current trajectory is unsustainable and, without considering significant course correction, the ERO and industry finds itself nearing a critical juncture where alternate methods to accomplish the development of mandatory Reliability Standards has become necessary. NERC is at risk of losing the confidence of U.S. regulatory authorities and industry executives in its ability to produce standards in a timely and efficient manner. The ability of the ERO to meet deadlines established by the NERC Board of Trustees is essential and the waiver provision will allow the Standards Committee to meet its obligations to the NERC Board.		
American Public Power Association	Yes	APPA submits the following comments in support of the proposed waiver provision and responding to comments by PSEG that object to proposed Section 16.0 Waiver and support retention of the existing Expedited Standard Development Process. For ease of reference, here are links to the two provisions that PSEG and I are referring to:Proposed Standard Processes Manual, Section 16.0 "Waiver," at page 49: http://www.nerc.com/docs/standards/sar/Appendix_3A_StandardsProcessesManual_clean_2012_08_27.pdf Expedited Standard Development Process of the current Standard Processes Manual, at page 34:

Organization	Yes or No	Question 6 Comment
		http://www.nerc.com/fileUploads/File/Appendix_3A_StandardsProcessesManual_20120131.pdfMy specific reasons for supporting for the Waiver Provision and my responses to PSEG's concerns are set out below:First, the current "Expedited Standard Development Process" really isn't a separate standards process at all. It's just a waiver provision by another name with a prescriptive list of actions that can be taken. However, the Expedited Process has a poison pill: as soon as the standard is adopted by the Board through the "expedited" process, NERC must either announce that the standard will expire after two years or repeat the entire standards process again to develop and approve the same standard or a modified standard. This is clearly redundant and a waste of resources for NERC, the industry and the drafting team. I know of no standards project since the Urgent Action 1200 cyber project where a sunset provision was deemed appropriate.Second, the first two bases for the Standards Committee to approve a Waiver (where necessary to meet a regulatory deadline or a deadline imposed by the Board of Trustees) are fundamentally the same as under the current Expedited Process (specific time constraints such as a regulatory directive or to meet an urgent reliability issue). However, the current SPM is ambiguous on who decides whether the reliability issue is in fact urgent and how urgent it is. Is it NERC staff? The Standards Committee? The drafting team? This type of prioritization decision should in fact be authorized by the Board. But it is the Standards Committee's responsibility to work with staff and the SDT to figure out how to meet such deadlines.Third, the other basis under which the SC is authorized to grant a waiver for any part of the SPM, in the absence of a regulatory or Board deadline, is limited only to where the proposed modification of the standard "has already been vetted by the industry through the standards development process or is so insubstantial that developing the modification through the processes contained in this manual will add significant time delay." To approve a waiver, the Standards Committee will be required to make a judgment about whether a specific issue has been fully vetted or is so insubstantial that it is a waste of industry and NERC time and resources to follow all of the normal steps in the standards process. The need for this part of the waiver provision should be self-evident in the fact that the current SPM led

Organization	Yes or No	Question 6 Comment
		to a substantial debate as to whether the SC was required to terminate work on the PRC-005-2 project and start over with a new SAR and drafting team after the ballot failed on a recirculation ballot in summer 2011. The SPM shouldn't drive NERC and the industry to do dumb things. Rather, we need to use the process to get to consensus in support of technically excellent standards. The SPM is a means to an end, not the end in and of itself.Fourth, any action by the SC to waive an element of the SPM will be done in public and will be fully noticed to the industry as a whole. The action will be taken by approval of a motion by the Standards Committee, not by NERC staff. The basis for the waiver will appear in the agenda package and minutes of the SC. Notice of the waiver will be included on the standard Project Page, the announcement of comment and ballot periods, as well as the development history of the project. There is no need to have a specific SPM text provision to require notice to take place. The NERC ROP already has an appeal procedure, so no entity need wait to appeal an SC waiver decision until it is presented to the Board at some later date. And if good cause for the waiver is not shown, the SC will be reversed by the Board. Fifth, PSEG recommends that the SPM be modified to require a public comment period on the SC's waiver decision and that the NERC Board approve the waiver before it goes into effect. This process not only adds a minimum of 45 days to the process and would likely entail scheduling of a special Board meeting to consider each waiver approved by the SC, more importantly it confuses roles and responsibilities. The registered ballot body elects the SC to represent the best interests of the industry and reliability. The SC also reports to and is responsible to the Board to accomplish duties set forth in its charter, which include working with NERC staff to manage the standards process. It makes no sense to require the Board to ratify process management decisions that have been delegated to the SC unless one or more entities disagree with the decision - and we have an appeals process for that purpose, to ensure timely due process. Sixth, even if the waiver provisions are utilized, I think the development history of the resulting standard is likely to comply with ANSI's fundamental tenets - but the SC can't guarantee that in advance, because it entails a waiver of the approved SPM. To date, NERC has not submitted any standards to ANSI for approval. Rather, NERC's practice

Organization	Yes or No	Question 6 Comment
		has been to submit the SPM to ANSI to gain approval as an accredited standards development organization (SDO). ANSI does not require an SDO to use the accredited process for all of its standards work, but if and when we depart from the ANSI approved process we shouldn't submit such standards to ANSI for approval.Seventh, industry consensus is still fully required. The new waiver provision does not change the voting rules, so approval still requires a 75% quorum, a two-thirds segment weighted supermajority approval, and responses to all comments raised, plus a final/recirculation ballot. Just like today. The waiver provision merely allows the SC to meet external deadlines and to avoid wasting industry and NERC resources, which is front and center what the Board directed us to do when it adopted the SPIG's recommendation that we take steps to improve the efficiency of the standards process. If the industry does not agree that the waiver is appropriate, the ballot pool will vote it down.Finally, the waiver provision is designed to enhance the ability of the SC to accomplish the SPIG's recommendation #5, to ensure timely development of reliability standards and make efficient use of industry and NERC resources, while adhering with ANSI principles:Recommendation 5: Standards Development Process and Resources The Board is encouraged to require the standards development process be revised to improve timely, stakeholder consensus in support of new or revised reliability standards. The Board is also encouraged to require standard development resources to achieve and address: o Formal and consistent project management o Efficient formation and composition of SDTsThanks for your consideration of these comments.
Response: Thank you for your comments and for your support. Your comments illustrate the need for the waiver provision.		
NextEra Energy	Yes	NextEra generally supports the clarification, but suggests that an additional option for a waiver be added: "In response to a national emergency declared by the United States or Canadian government that involves the reliability of the BES or cyber attack on the BES." NextEra also recommends that the following be added as a lead in to ensure that stakeholders have adequate notice of a possible waiver: "With the exception of a waiver addressing a national emergency, all potential waivers must be

Organization	Yes or No	Question 6 Comment
		noticed to stakeholders 5 business days in advance of any consideration by the Standards Committee."
Response: Thank you for your comments and for your support. The concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee has been incorporated.		
Detroit Edison	Yes	
Western Small Entity Comment Group	Yes	
SPP Standards Review Group	Yes	
Dominion	Yes	
Arizona Public Service Company	Yes	
Idaho Power Co.	Yes	
WECC	Yes	
Essential Power, LLC	Yes	
American Transmission Company	Yes	
City of Jacksonville Beach, FL dba/Beaches Energy Services	Yes	
EPSA		See comprehensive comments in Question 7.

Organization	Yes or No	Question 6 Comment
Response:		
Exelon Corporation and its affiliates		Exelon believes there remains ambiguity in the waiver process and there need to be additional details added, such as: o There should be a further explanation of why and under what circumstances a waiver would be used for a modification to a proposed standard or requirement, etc. as articulated in the third bullet under the provisions for a waiver. As there is a limitation that a waiver cannot be used to modify the voting requirements for a proposed standard, it is not clear under what circumstances an issue that has been "vetted by the industry through the standards development process" would be subject to a waiver. o Who can request a waiver or is the waiver limited to the Standards Committee members? o How will record of the decision to use the waiver process be documented and made known to stakeholders other than the BOT?
Response: Thank you for your comments. Section 16.0 does not specify the identity of parties that may request a waiver because consistent with the openness and transparency of the standard development process, a waiver may be requested by anyone. Additional language has been added to address this concern which clarifies this point. **The record of the decision on the waiver request will be documented by NERC staff and maintained on the relevant project page on the NERC website. In response to stakeholders concerns regarding transparency, openness and due process protections, we have incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee. Finally, we have added a footnote indicating that any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.**		

7. If you have any other comments on these proposed revisions that you haven't already mentioned above, please provide them here.

Summary Consideration: Stakeholders made a variety of suggestions and the drafting team considered each of the suggestions. Please refer to the individual responses below. Two issues that were identified by multiple stakeholders were related to the handling of SARs and consideration of Canadian federal holidays.

With respect to criteria for accepting or rejecting SARs and for retirement of a standards development project:

The Standards Committee is currently exploring whether there should be additional process(es), further guidelines and/or criteria for various Standards Committee decision points within the SPM such as acceptance rejection of a SAR or other drafting team output, when and how to terminate a standards development project, etc. This may be addressed a process documents or guidelines that support, but are not part of the SPM, or may be addressed in future revisions to the SPM. This matter is not ripe for inclusion in the current revision of the SPM.

With respect to consideration of Canadian federal holidays:

Regarding Section 4.9, the reference to federally-recognized United States Holidays is intended to acknowledge that NERC's offices that accept and process ballot submissions, which are located in the United States, are not open on these dates. While the Standards Committee and NERC staff make every consideration possible to posting conflicts, the Standards Committee did not feel it was necessary to codify this in the SPM. Since there are several representatives on the Standards Committee from Canadian entities, they can help ensure the other members are aware of Canadian-specific conflicts of any nature. No change made.

Organization	Yes or No	Question 7 Comment
ACES Power Marketing Standards Collaborators		(1) In section 1.4 on page 3, we suggest documenting that not only does Section 304 of the NERC Rules of Procedure compel an open and transparent standards development process but the Energy Policy Act of 2005 compels the same. Specifically, the statute requires "reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards". (2) While section 3.4 clarifies that the Standards Committee (SC) has the authority to remand, reject, or accept the work of the drafting team, we suggest that

Organization	Yes or No	Question 7 Comment
		the SC develop guidelines or criteria for why they do so. This will avoid conflicts of interest in which SC members may not like the outcome of a perfectly valid standard.(3) We suggest the SC develop criteria and guidelines for why a standard will be developed. Just because a SAR is presented does not mean it is wise to develop a standard. The bar for submitting a SAR is not very high. There are many reliability issues that can be addressed outside the standards development process in a more expeditious fashion. For example, NERC alerts, lessons learned, partnering with the North American Transmission Forum and North American Generation Forum among other outreach initiatives can be used to address reliability issues rapidly. We have heard some say that a standard needs to be developed for key issues because "industry won't do it without a standard". If a standard always compelled the exact reliability behavior that FERC and NERC desire, there would be no standard violations. We obviously know that is not the case. Sometimes, industry (despite wanting to do the right thing) simply does not understand what is expected which further supports the need for other types of outreach besides developing a standard. The bottom line is that the criteria can't be that a standard is the only way we can compel the desired reliability outcome because numerous violations clearly indicate that standards often do not work. (4) Section 3.6 clarifies that the SC shall appoint industry experts to standards drafting team and NERC "shall appoint drafting teams that develop Interpretations." We suggest that the language regarding NERC appointing interpretation drafting teams to be made clear that NERC is appointing industry experts as well. (5) Several of the rationale boxes were truncated. We were not able to deduce the full rationale of the changes proposed by the SC as a result. (6) The language that a SAR can be rejected "for good cause" in Section 4.1 needs to be expanded. We suggest the SC develop criteria for what constitutes good cause. These criteria should be included in this standards process document or it should be referenced. (7) Sections 4.2 and 4.3 need to be further expanded to clarify that SC will only use another process besides public nomination for selecting a drafting team in extraordinary circumstances. The public nomination process should be used for nearly all standards development efforts. Furthermore, we suggest that the SC

Organization	Yes or No	Question 7 Comment
		should develop criteria or a process for identifying when the public nomination process may not be used. For example, the only times we can fathom that another process would be used would be for a confidential issue related to national security that would require necessary security clearances or to address an aggressive regulatory deadline that is likely related to an imminent threat to reliability and time does not allow for the use of public nomination. (8) Section 4.2 clarifies that the drafting team will determine if there is support for a SAR. Without a ballot, how can the drafting team possibly gauge support? There have been many draft standards that receive little support despite the belief by the standards drafting team that they have developed a standard that is supported by industry. They only discovered the lack of support during the ballot because comments can be submitted by more than just the registered ballot body and can simply be misinterpreted(9) Section 4.6 states that the detailed results of the quality review shall be provided to the Standards Committee. We do not believe that is actual practice. We believe the quality review is only provided to the standards drafting team. If this is correct, we suggest modifying the section accordingly. (10) Section 4.15 should clarify under what circumstances a SC will decide to continue working on a standard that has failed the Final Ballot. There should be a high bar such as satisfying a regulatory deadline for the SC to do this. If the Registered Ballot Body has determined a proposed standard is not satisfactory by voting the standard down, continuing to develop a standard does not reflect their authority in the process. This authority should only be overridden by a higher body such as FERC through a regulatory deadline. After all, this is supposed to be a final ballot. It is not truly a final ballot, if more actions will be directed by the SC.

Response: (1) Regarding Section 1.4, thank you for your suggestion. We agree that NERC Rule of Procedure Rule (ROP) 304 is consistent with the requirements of EPA 2005. Because there are many instances where the SPM, the NERC ROP and other NERC documents align with the statute, it would be cumbersome to reference the statute repeatedly. The suggested edit is unnecessary.

(2), (3), (6) and (10) The Standards Committee is currently exploring whether there should be additional process(es), further guidelines and/or criteria for various Standards Committee decision points within the SPM such as acceptance rejection of a SAR or

Organization	Yes or No	Question 7 Comment
		other drafting team output, when and how to terminate a standards development project, etc. This may be addressed a process documents or guidelines that support, but are not part of the SPM, or may be addressed in future revisions to the SPM. This matter is not ripe for inclusion in the current revision of the SPM; however, your comment is noted and will be considered during the ongoing work of the Standards Committee. (4) Section 7.0, Process for Developing an Interpretation provides: "If the Standards Committee accepts the Interpretation request, the NERC Standards Staff shall form a ballot pool and assemble an Interpretation drafting team with the relevant expertise to address the interpretation." Therefore, it is unnecessary to include additional language regarding interpretation drafting teams in Section 3.6. (5) The SCPS is unable to reproduce the described problem with the rationale boxes. We apologize for any inconvenience. You may contact your segment representative on the SC for more detailed information regarding the rationale of the proposed changes. (7) Thank you for the comment. However, the Standards Committee feels that flexibility is needed in this area, and spending time developing more process will not benefit the overall process improvements at this time. (8) Thank you for your comment. Voting on SARs was removed in a previous version of the SPM that was approved by the industry, as a means to expedite the process. The Standards Committee is currently exploring whether there should be an additional process(es), further guidelines for various Standards Committee decision points within the SPM such as acceptance rejection of a SAR or other drafting team output, when and how to terminate a standards development project, etc. This may be addressed a process documents or guidelines that support, but are not part of the SPM, or may be addressed in future revisions to the SPM. This matter is not ripe for inclusion in the current revision of the SPM; however, your comment is noted and will be considered during the ongoing work of the Standards Committee. (9) This language was a carryover from a former practice that included a review by the Standards Committee. We agree it is no longer in practice and modifications have been made.
ISO/RTO Council's Standards Review Committee		1. The footer in the main page is erroneous, given the recent relocation of the NERC offices to Atlanta.2. We believe there should be an obligation on NERC to file a Board-approved Standard with appropriate regulatory bodies within 30 to 60 days.3. We believe that there should be a limit on the number of Additional Ballots that are required/can be performed, so that the Industry has an opportunity to appropriately affect the outcome of a Standards project through a reballot.4. We believe the VRFs and VSLs should be eliminated from the Standards Development Process.5. We

Organization	Yes or No	Question 7 Comment
		believe that the revision should include the changes to incorporate the formation of the Reliability Issues Steering Committee (RISC).6. The annual solicitation of projects by NERC Staff is no longer needed and should be eliminated, we have a backlog of Standards Projects in the plan and there is no need to ask for more work in this area; if there is an identified reliability need, a SAR should be submitted.7. The proposed elimination of the ability to appeal from the SPM is not acceptable.8. We do not support addition of section 4.18 which appears to give the Board additional authority outside of Process; any withdrawals should go through the industry for balloting.However, if the decision is to move forward with the section there is a significant issue which can result from the process as written. The process does not consider the impact if another governmental entity, such as a Canadian entity, has approved the standards. This impact should be considered.9. We do not support the proposed addition of the paragraph (in Section 7.0) which reads "The NERC Reliability Standards and Legal Staff shall review the final Interpretation to determine whether it has met the requirements for a valid Interpretation. Based on this review, the NERC Reliability Standards and Legal Staff shall make a recommendation to the NERC Board of Trustees regarding adoption." We believe this is the responsibility of the SC.10. Section 7.0 - The statement "[i]f the Standards Committee accepts the Interpretation request, the NERC Standards staff shall form a ballot pool and assemble an Interpretation drafting team with the relevant expertise to address the interpretation." As written it could be assumed that the ballot pool is formed at the same time as the drafting team is assembled which is not the case according to Figure 2 Process for Developing an Interpretation. 11. Section 7.0 - It is unclear why the textual description of the processes for conducting the Quality Review and the Standards Committee approval were deleted from this section and replaced with "Interpretations will be balloted in the same manner as Reliability Standards." By deleting these steps, which occur prior to the balloting process, it could be implied that Quality Reviews will no longer be done and the Standards Committee will no longer approve Interpretations for posting.12. We do not support the proposed addition of the paragraph (in Section 10.0) which reads "NERC Board of Trustees may

Organization	Yes or No	Question 7 Comment
		direct the development of a new or revised Reliability Standard to address a national security situation that involves confidential issues...." We believe this resides within the authority of FERC.13. Sections 10.1 through 10.7 - Response to Imminent, Confidential Issue - This process has become a black box. There is not interface with the Standards Committee except at the Chair and Vice Chair level. It is unclear as to how people will be notified as to when they can register for the ballot pool, what are the processes to determine when the standards should be available for formal stakeholder comments, etc. It is unclear why there is no opportunity for an Additional Ballot if the drafting team makes considerable changes to the standards.14. Sections 10.8 through 10.4 - Response to Non-imminent, Confidential Issue - Figure 4: Developing a Standard Responsive to a Non-imminent, Confidential Issue indicates the Standards Committee approves to post for Comment and Ballot (the first step 3). However, there is no mention in the textual description of the process that the Standards Committee will approve for posting. It is unclear why the Comment Period and Ballot may be abbreviated if the issue being address is not imminent (the second step 3).15. Section 13.0 - We do not support the five-year review modification to ten-years. We believe that the five-year review, had it been enforced, we would be in a position that the Paragraph 81 initiative would not be a necessity.However, if the decision is to move forward with limiting the 5 year review to ANSI approved Standards, the Standards Process Manual should be updated to include a process that specifies how/when a BOT approved standard will be submitted to ANSI for approval. As noted in the rationale there are no standards submitted to ANSI. Without having a process in place identify standards for submittal to ANSI, by default all standards will move to a ten year review.16. There appears to be contradictory language regarding establishing a quorum. These are both confusing and we suggest clarifying this language and making it consistent.17. Section 1.4 - Under Balance bullet it indicates "[t]he Registered Ballot Body serves as the consensus body voting to approve each new or proposed Reliability Standard, definition, Variance, and Interpretation." Suggest this be changed to "approve or reject". Also suggest adding a statement that they approve or reject retirement of a

Organization	Yes or No	Question 7 Comment
		Reliability Standard, definition, Variance, and Interpretation.18. Section 1.4 - Under the new Metrics bullet it indicates that the standards apply in portions of Mexico. Section 1.3 indicates that the standards are applicable in the United States and through applicable authorities in Canada. There is no other mention of Mexico in the SPM other than the new section. If the standards are applicable in Mexico, we suggest additional conforming changes be made to the SPM where appropriate such as Section 3.7 Governmental Authorities, and Section 10 Process for Developing a Reliability Standard Related to a Confidential Issue.19. Section 2.5 - The following statement was added. "The Components of a Reliability Standard may include the following." This statement would imply that none of the elements such as Title, Number, Purpose, Applicability, Effective Date, or even Requirement are required in a Reliability Standard. Though there are some items that may be included in a Reliability Standard such as Application Guidelines and Procedures there are some items that should always be required. The SPM should delineate between what is always required and what is optional rather than indicating everything is optional.20. Footnote 5 - More information on where the Sanctions Guidelines of the North American Electric Reliability Corporation document is posted (such as the web page) would be helpful other than to indicate it is posted somewhere on the NERC Web Site. Also, we do not think it is appropriate to have footnotes embedded in footnotes. Footnote 6 is included in footnote 5.21. Section 3.1 - We suggest that under the Board of Trustees the scope be expanded to include approval of retirements as well as withdrawals of Reliability Standards, definitions, Variances, or Interpretations to be consistent with other sections of the document.22. Section 3.4 - New language was added to allow the Standards Committee to disband a drafting team. However, the SPM does not provide the next steps. It would be beneficial to outline the options available to the Standards Committee once they disband a drafting team, such as terminate the project, create a new team, place the project on hold, etc.23. Section 3.6 (Drafting Team) indicates the drafting team may consist of technical, legal and compliance experts, while section 4.3 (Form Drafting Team) makes references to regulatory rather than legal. It would be appropriate to use

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		consistent terminology. Also in section 4.3 there is no reference to including compliance experts. This seems inconsistent.24. Section 4.1 through 4.3 - Appointing drafting team during the SAR process - It is unclear in reading these sections as to what conditions determine if a drafting team is/is not created to assist in developing the SAR. Additional clarification would be helpful. 25. Section 4.5 - The revisions remove the minimum duration of 30 days for informal comments. We recognized that there are situations such as webinar's, meetings, etc. where comments could be gathered in less than 30 days. However, we would recommend if the standard is posted for informal comments that a minimum guideline be included in the SPM for soliciting the informal comments. We believe in these situations, 30 days is a reasonable timeframe for soliciting informal written comments.26. Section 4.6 - Indicates the quality review will be done in accordance with the Standards Committee's approved procedures for conducting Quality Reviews. We could not find where these procedures posted? On the Reliability Standards Resources web page we found the Draft Template for Quality Review of a NERC Reliability Standard but no procedures. We would also recommend that there be a set time limit from when the NERC Reliability Standards Staff receives a request to conduct a Quality Review to when the Quality Review is completed.27. Sections 4.9 through 4.15 -- By removing the Initial Ballot reference in the SPM and then adding capitalized terms for Additional Ballot and Final Ballot has added confusion to the SPM. We would suggest: a) adding the Initial Ballot process back into the type of Ballots so there are no gaps in types of ballots; b) additional clarity be added to specify whether there can be one and only one Final Ballot: and c) additional clarity be provided by what is meant by not having to respond to comments in a previous ballot.28. Section 5.1 - states the "[i]f the SAR identifies a term that is used in a Reliability Standard already under revision by a drafting team, the Standards Committee may direct the drafting team to add the term to scope of the existing project." In this situation it is unclear as to what happens with the SAR. Additional clarity on what happens to a SAR that is incorporated into an existing project would be beneficial.29. Section 6.1 - What is meant by "the Standards Committee may direct the team to withdraw the SAR until

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		the data has been collected and analyzed"? By withdrawing the SAR: a) is it rejected and a new SAR will need to be submitted; b) does it place the SAR in a hold status until the field test has been completed or; c) are their multiple options for what may happen when the SAR is withdrawn. Additional clarity on the available options to the Standards Committee would be helpful.30. Section 9.1 Interconnection-Wide Variances makes an invalid assumption in that an interconnection-wide variance would be applicable to one Regional Entity and that the standards should be developed through that Regional Entity's NERC-approved Regional Reliability Standards development procedure. If there is a variance that is applicable to the Eastern Interconnection which Regional Reliability Standards development procedure should be used?31. Advisor or Coordinator - in some instances the term advisor is used in one instance the term coordinator is used. Are these the same? If so, we suggest consistently using the same term.32. References to NERC staff should be consistent. Sometimes the term NERC Reliability Standards Staff is used an in some instances NERC Standards Staff is used. For example, see Section 7.0 third paragraph.33. We recommend a thorough review of Reliability Standards Resources web page document references be conducted. We have found: o There are numerous references to documents found on the Reliability Standards Resources web page where the documents referenced in the SPM do not match the document names on the web page or the name in the document. For example, "market interface principles" is used in the SPM (section 2.3 and footnote 2). The document posted is Market Principles. o The SPM should also consistently use the same name when referencing a document. For example, the SPM sometimes uses "Ten Benchmarks of an Excellent Reliability Standards." Other sections reference "NERC's Benchmarks for Excellent Standards." o If a document is identified as being on the Reliability Standards Resources web page verify it is currently on the web page. For example footnote 23 indicates the NERC NAESB Template for Joint Standards Development and Coordination is posted on the Reliability Standards Resources web page. The same is applicable for footnote 24 which references the Process for Approving Data Collection and Analysis and Field Test Associated with a Reliability

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		Standard. We could not find these documents posted on the web page.

Response:

1. **The suggested edit is accepted. The footnote on the cover page will be changed to reflect the current NERC address in Atlanta.**
2. **In the recent 2 years, NERC staff has greatly improved the processes and timing for getting items filed timely with FERC. The items that are held longer than typical are done so deliberately and thoughtfully. The Standards Committee believes that flexibility is needed in this area, and will continue to monitor NERC's performance.**
3. **Regarding the comment to limit the number of ballots, an intentional decision was made not to put an arbitrary limitation in place. While it might be clear in some cases after one or two ballots whether a standard is going to be successful, in other cases it may take much longer for consensus to arise. We believe this issue is better handled by the authority the SC has to terminate a project if it does not believe consensus can be achieved. An arbitrary limit could require a project to be restarted just as consensus is about to be reached.**
4. **The NERC SCPS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards. The elimination requires the development of a replacement to the existing Penalty Matrix, which supports and incorporates the risk based concepts into the enforcement process. In support of these efforts, the SCPS is continuing to work toward the elimination of the VRFs and the VSLs through further development of the 'Sanctions Table' concepts originally proposed during the initial formal comment period and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts.**

   While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS has further developed guidance for the SDTs to assist with the development of the VRFs and VSLs.
5. **It is still unclear what role the RISC will play, in regards to the front end of Standards Development. Until that is understood, no changes will be made to the SPM.**
6. **We agree this area should be reconsidered. However, this matter is not ripe for inclusion in the current revision. Thank you for your support of the proposed changes to the SPM.**
7. **No change to the appeals process was made. References to the process in some sections were eliminated, but section 8 makes**

Organization	Yes or No	Question 7 Comment
		clear that "any procedural action or inaction related to the development, approval, revision, reaffirmation, retirement or withdrawal of a Reliability Standard" may be appealed. No substantive changes were made to this section. 8. We agree that a withdrawal should go through an industry ballot. Modifications to the SPM have been made. 9. The purpose of the final review of the Interpretation is to ensure that the final product comports with the requirements set forth in the Standard Processes Manual. This step fulfills the obligations of NERC Staff to their corporate board and provides accountability. 10. We believe the text and the figure are consistent, regarding NERC staff actions after the SC accepts an interpretation request. Additional clarification to demonstrate that these activities are not done at the same time would not contribute to the overall improvement of the SPM. No change was made. 11. Details regarding Quality Reviews and Standards Committee approval are in Section 4 (and its subsections). Instead of reiterating those steps in Section 7.0, the language was removed and a reference to the standards development process was added. These steps are still required, as you can see in the flow chart. No changes were made. 12. With respect to the ability of NERC to direct the development of a new or revised standard to address a national security situation that involves confidential issues is not new to this revision. No substantive changes to this provision are proposed in this revision. Also NERC's authority in this area is concurrent with that of FERC, not exclusive. No change made. 13. With respect to comment 13, no substantive changes to this provision are proposed in this revision. Although there is some reduction in transparency necessary to protect the confidential issues involved, the provisions balance the need for confidentiality with the needs of the Ballot Pool for relevant information. No change made. 14. With respect to comment 14, we have made changes to the process flow chart to correct the issues you identified. Thank you for identifying these issues. 15. With respect to comment 15, the move to a ten year review period was deemed appropriate to enable the limited industry resources available to be put to their most effective use. While we certainly understand the advantages of a more frequent review, including those you noted, we believe there is a consensus in the industry for the increased flexibility this change provides. No change made. 16. Although different phrasing is used in two different sections, we do not see an actual conflict. However, modifications have been made. Recommend the following modification in parts 1.4 and 4.10. (Rejecting the change to 4.10) "A quorum, which is established by at least 75% of the members of the ballot pool submitting an affirmative vote, a negative vote, or an

Organization	Yes or No	Question 7 Comment
abstention” 17. Thank you for your comment. We will take this clarification under consideration for the next revision. 18. The SPM was reviewed for all places where Canada was mentioned, to see if it was appropriate to also add Mexico. Since NERC does not have a MOU with Mexico or any part of Mexico, we felt it was not appropriate to treat it the same way in the SPM. (Note: WECC enforces some standards in Baja.) No changes were made. 19. FERC has held that only the Requirements and Applicability components of a standard are enforceable. While not required, the other components of a Reliability Standard listed in Section 2.5 are important for a complete understanding of the standard. To make clear that all of the listed components should be included in a draft standard without suggesting that they are all "required", Section 2.5 will be edited to remove the word "may". The phrase will read as follows: "The Components of a Reliability Standard include the following. . ." 20. Regarding the content of footnote 5, more information regarding exactly where the Sanctions Guidelines are located on the NERC web-page will not be included at this time because the NERC web-page is subject to change more frequently than the SPM. The issue with the placement of footnote 6 appears to be a typographical formatting error that resulted when tracked changes were accepted in the document. The formatting will be corrected to ensure that footnote 6 is independent of footnote 5. 21. Thank you for your comment. We will take this clarification under consideration for the next revision. 22. The Standards Committee is currently exploring whether there should be additional process(es), further guidelines and/or criteria for various Standards Committee decision points within the SPM such as acceptance rejection of a SAR or other drafting team output, when and how to terminate a standards development project, etc. This may be addressed a process documents or guidelines that support, but are not part of the SPM, or may be addressed in future revisions to the SPM. This matter is not ripe for inclusion in the current revision of the SPM; however, your comment is noted and will be considered during the ongoing work of the Standards Committee. 23. Agreed. Modifications have been made. 24. The decision to provide the SC discretion in creating a drafting team to assist with SAR development was intentional. The proposed language gives the SC the flexibility needed to create such a team only in scenarios where it believes a team would be helpful and would justify the associated resources. No change made. 25. A crucial aspect of the SPM revisions is to provide flexibility to make the standards development process as efficient as		

Organization	Yes or No	Question 7 Comment
		possible. While we agree that 30 days is a reasonable time frame in many situations, the choice was made not to bind the industry to a specific period in this informal feedback gathering stage. No change made.
		26. The procedures for conducting a quality review are currently being revised by the SCPS. Your recommendation for a time limit between receiving a request and completing the review will be taken into consideration as those procedures are developed.
		27. With respect to comment 27, a) Initial Ballot was replaced by Ballot. Section 4.7 is where the first Ballot is conducted. The sections that follow are sequential in their references to an Additional Ballot or Final Ballot. No change made. b) As states in Section 4.15, there is no limit to the number of ballots that may be conducted. This includes Final Ballots. No change made. c) Section 4.31 is clear that a formal response to all comments is required prior to conducting a Final Ballot. We believe the language you are referring to clearly communicates that if an Additional Ballot will be conducted, no formal response to comments from previous ballots is required. No change made.
		28. The Standards Committee is currently exploring whether there should be additional process(es), further guidelines and/or criteria for various Standards Committee decision points within the SPM such as acceptance rejection of a SAR or other drafting team output, when and how to terminate a standards development project, etc. This may be addressed a process documents or guidelines that support, but are not part of the SPM, or may be addressed in future revisions to the SPM. This matter is not ripe for inclusion in the current revision of the SPM; however, your comment is noted and will be considered during the ongoing work of the Standards Committee.
		29. The Standards Committee is currently exploring whether there should be additional process(es), further guidelines and/or criteria for various Standards Committee decision points within the SPM such as acceptance rejection of a SAR or other drafting team output, when and how to terminate a standards development project, etc. This may be addressed a process documents or guidelines that support, but are not part of the SPM, or may be addressed in future revisions to the SPM. This matter is not ripe for inclusion in the current revision of the SPM; however, your comment is noted and will be considered during the ongoing work of the Standards Committee.
		30. Thank you for your comment. However, this suggestion is out of scope for this revision and would not contribute to an overall improvement of the SPM. We will retain this issue for a future revision.
		31. Regarding the issue of advisor versus coordinator, each word is only in the text one time, and in both cases it is used in a general use of the word (dictionary), rather than as a job title. We believe it is appropriate to leave the text as is.
		32. Thank you for your comment. The issue raised does not present a substantive problem that requires correction at this time.

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33. A reconciliation of the Resources webpage will be conducted. However, modifications may have to be made in a future revision to the SPM.		
American Public Power Association		A special note of thanks to the SCPS, SCCPS and NERC staff, and to all industry stakeholders that have contributed to revision of the NERC Standard Processes Manual. A phenomenal amount of very high quality development work and systematic outreach to industry was completed over a period of just five months, to move the broadly outlined recommendations of the SPIG from concept to industry ballot. You are to be commended for that effort.
Response: Thank you for your comment.		
Canadian Electricity Association		CEA wishes to raise one issue, which was briefly addressed by the SDT and the SCPS in the consideration of comments from the first comment period.The SPM revisions include new language in Section 4.9, which reads as follows: "If the last day of the ballot window falls on a Saturday, Sunday or federally-recognized United States holiday, the period does not end until the next business day." In response, a CEA member requested that equal consideration be given to statutory holidays in Canada.In its official consideration of comments, the SCPS said that adding more holidays to the calendar of days when a ballot or other action cannot close would be "counter to the SPIG recommendations which are calling for improvements to shorten the process."As the national representative of NERC members and registered entities in Canada, CEA calls on the SDT and SCPS to re-consider. CEA acknowledges that this issue may appear to be a minor one; however, we believe that it is a matter of principle for an international organization like NERC, which is accountable to members and governmental authorities in both the United States and Canada. NERC should seek to afford equal consideration to the interests, concerns and - in scenarios such as this - customs of its stakeholders on either side of the border. CEA finds the SCPS' argument to be unpersuasive and unreasonable. We request that the language

Organization	Yes or No	Question 7 Comment
		in Section 4.9 be modified, as follows: "If the last day of the ballot window falls on a Saturday, Sunday, federally-recognized United States holiday, or holiday in the majority of Canadian jurisdictions, the period does not end until the next business day."
Response: Regarding Section 4.9, the reference to federally-recognized United States Holidays is intended to acknowledge that NERC's offices that accept and process ballot submissions, which are located in the United States, are not open on these dates. While the Standards Committee and NERC staff makes every consideration possible to posting conflicts, the Standards Committee did not feel it was necessary to codify this in the SPM. Since there are several representatives on the Standards Committee from Canadian entities, they can help ensure the other members are aware of Canadian-specific conflicts of any nature. No change made.		
HHWP		-Comment A- Can the SPIG please check the Rational provided for Section 2.5. It does not appear relevant. Rationale: Section 2.5 has been updated to reflect the SPIG recommendation that redundant elements of a standard be eliminated, as well as a recomm
Response: The Rationale statements are a communication tool intended to provide commenters with background on the proposed changes and guide comments. The Rationale statements will be removed when the final changes are approved, and are not part of the SPM. Part of the rational statement that was originally posted related to the proposal to replace VRFs and VSLs, but the proposal did not have sufficient industry support in the first round of comments. The VSL/VRF language was added back into this version of Section 2.5, and the related language in the rationale statement was removed accordingly. What remains of the rationale statement in this posting explains the other, minor changes to Section 2.5 that were made prior to the last posting that more clearly articulate the components of a reliability standard and how they related to the Requirements of a Reliability Standard.		
NPCC		Comments: The following additional comments: o The footer in the main page is erroneous, given the recent relocation of the NERC offices to Atlanta. o There should be an obligation on NERC to file a Board-approved Standard with appropriate regulatory bodies within 30 to 60 days. o There should be a limit on the number of recirculation ballots that are required/can be performed, so that the Industry has an

Organization	Yes or No	Question 7 Comment
		opportunity to appropriately affect the outcome of a Standards project through a re-ballot. o The VRFs and VSLs should be eliminated from the Standards Development Process. o The revision should include the changes to incorporate the formation of the Reliability Issues Steering Committee (RISC). o The annual solicitation of projects by NERC Staff is no longer needed and should be eliminated. There is a backlog of Standards Projects in the plan and there is no need to ask for more work in this area. If there is an identified reliability need, a SAR should be submitted. o The proposed elimination of the ability to appeal from the SPM is not acceptable. o We do not support addition of section 4.18 which appears to give the Board additional authority outside of Process. Any withdrawals should go through the industry for balloting. o We do not support the proposed addition of the paragraph (in Section 7.0) which reads "The NERC Reliability Standards and Legal Staff shall review the final Interpretation to determine whether it has met the requirements for a valid Interpretation. Based on this review, the NERC Reliability Standards and Legal Staff shall make a recommendation to the NERC Board of Trustees regarding adoption." This is the responsibility of the SC. o We do not support the proposed addition of the paragraph (in Section 7.0) which reads "NERC Board of Trustees may direct the development of a new or revised Reliability Standard to address a national security situation that involves confidential issues...." This resides within the authority of FERC. o We do not support the five year review modification to ten years. The enforcement of the five year review would have made the Paragraph 81 initiative unnecessary. o Regarding the No voting without responses, NERC should change their tool such that the submitter gets an error message unless something is included in the comments field. This would appropriately resolve the issue. o The present SPM has an "expedited standards development process" that was stricken. However, the RoP section 300 (Reliability Standards Development) requires that process. Section 309.3 references it. The SPM should retain that. Without it in the SPM, NERC cannot respond to a request from a governmental authority for expedited development of a standard. The SPM therefore needs to retain that procedure, and if this provision were reinstated, the use of a waiver process would be minimized since

Organization	Yes or No	Question 7 Comment
		the expedited process would be a provision of the SPM. o The proposed version of Section 16.0: Waiver of the SPM (from the clean version, p. 49) allows the Standards Committee wide latitude to waive any SPM provision. From the document: "The Standards Committee may waive any of the provisions contained in this manual for good cause shown, but limited to the following circumstances: o Where necessary to meet regulatory deadlines; o Where necessary to meet deadlines imposed by the NERC Board of Trustees; or o Where the Standards Committee determines that a modification to a proposed Reliability Standard or its Requirement(s), a modification to a defined term, a modification to an interpretation, or a modification to a variance has already been vetted by the industry through the standards development process or is so insubstantial that developing the modification through the processes contained in this manual will add significant time delay.In no circumstances shall this provision be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard. The Standards Committee shall report the exercise of this waiver provision to the Board of Trustees prior to adoption of the related Reliability Standard, Interpretation, definition or Variance.Reliability Standards developed as a result of a waiver of any provision of the Standard Processes Manual shall not be filed with ANSI for approval as American National Standards."The use of a waiver will result is a violation of the NERC's American National Standards Institute (ANSI) approved standards development process. Otherwise, the last highlighted sentence above would not be needed. Reporting the use of a waiver prior to the Board of Trustees (BOT) adopting a standard is unacceptable (refer to "The Standards Committee shall report the exercise of this waiver provision to the Board of Trustees prior to adoption of the related Reliability Standard, Interpretation, definition or Variance."). The exercise of the waiver and BOT approval may be separated by years of work by the both the Standards Committee (SC) and the standards drafting team (SDT). Each exercise of a SC waiver should have BOT finality so that the BOT will not be pressured to approve any waiver in order to not reject the substantial body of work that has followed the exercise of the waiver by the SC. At a minimum, waivers to the SPM should be preceded by the

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		following:a. The posting of an SC document to the Registered Ballot Body that describes the reason for the requested waiver, including the threat to reliability, and what processes would be affected by the waiver.b. A short (10 day) period for accepting Registered Ballot Body comments.c. After comments are received, the SC may either withdraw the waiver or request its expedited approval by the NERC board, ensuring that the Board is supplied with the comments received. The entire process proposed above could be completed within 30-45 days, causing a minor delay for the hopefully rare exercise by the SC of waiving a SPM provision. o The extension of the ballot window when the last day falls on a Saturday, Sunday or federally-recognized United States holiday, should be modified to include Canadian holidays. It must be recognized that the document applies continent-wide.

Response: 1) The suggested edit is accepted. The footnote on the cover page will be changed to reflect the current NERC address in Atlanta.

2) In the recent 2 years, NERC staff has greatly improved the processes and timing for getting items filed timely with FERC. The items that are held longer than typical are done so deliberately and thoughtfully. The Standards Committee believes that flexibility is needed in this area, and will continue to monitor NERC's performance.

3) Regarding the comment to limit the number of ballots, an intentional decision was made not to put an arbitrary limitation in place. While it might be clear in some cases after one or two ballots whether a standard is going to be successful, in other cases it may take much longer for consensus to arise. We believe this issue is better handled by the authority the SC has to terminate a project if it does not believe consensus can be achieved. An arbitrary limit could require a project to be restarted just as consensus is about to be reached.

4) The NERC SCPS agrees with the commenter in that the ultimate goal is to eliminate the VRFs and VSLs from the Reliability Standards. The elimination requires the development of a replacement to the existing Penalty Matrix, which supports and incorporates the risk based concepts into the enforcement process. In support of these efforts, the SCPS is continuing to work toward the elimination of the VRFs and the VSLs through further development of the 'Sanctions Table' concepts originally proposed during the initial formal comment period and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts.

While the concepts that support the elimination of the VRFs and VSLs are vetted, the SCPS is actively developing concepts in

Organization	Yes or No	Question 7 Comment
		response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. In support of these efforts the SCPS has further developed guidance for the SDTs to assist with the development of the VRFs and VSLs. 5) It is still unclear what role the RISC will play, in regards to the front end of Standards Development. Until that is understood, no changes will be made to the SPM. 6) We agree this area should be reconsidered. However, this matter is not ripe for inclusion in the current revision. Thank you for your support of the proposed changes to the SPM. 7) With respect to the comment regarding the appeals process, no change to the appeals process was made. References to the process in some sections were eliminated, but the appeals process itself still remains in section 8.0. 8) Agree that a withdrawal should go through an industry ballot. Modifications to Section 4.18 of the SPM have been made. 9) The purpose of the final review of the Interpretation is to ensure that the final product comports with the requirements set forth in the Standard Processes Manual. This step fulfills the obligations of NERC Staff to their corporate board and provides accountability. 10) With respect to the ability of NERC to direct the development of a new or revised standard to address a national security situation that involves confidential issues is not new to this revision. No substantive changes to this provision are proposed in this revision. Furthermore, NERC's authority in this area is concurrent with that of FERC, not exclusive. No change made. 11) With respect to the comment regarding the change to the 5 year review process, the move to a ten year review period was deemed appropriate to enable the limited industry resources available to be put to their most effective use. While we certainly understand the advantages of a more frequent review, including those you noted, we believe there is a consensus in the industry for the increased flexibility this change provides. No change made. 12) The suggestion for "change [the] tool such that the submitter gets an error message unless something is included in the comments field." will be communicated to NERC Staff for possible incorporation to the balloting software. 13) With respect to the comment regarding an expedited review process, we believe that Section 16 of the SPM which provides the SC the authority to waive various provisions of the standards development process in specified situations is more than adequate to meet the requirement for an expedited process found in the ROP section 309.3. Note that Section 16 of the SPM specifically lists the need to meet a regulatory deadline as a justification for a waiver. The waiver section also provides more

Organization	Yes or No	Question 7 Comment
		flexibility to the SC than a specified procedure would. No change made. 14) The waiver provision would not violate ANSI. The currently-effective Standard Process Manual already provides a process for the expedited development of Reliability Standards where necessary "to meet an urgent reliability issue such that there isn't time to follow all the steps in the normal Reliability Standards development process." The waiver provision replaces this section in its entirety. In the currently-effective Standard Process Manual, the section on Processes for Developing a Reliability Standard Related to a Confidential Issue states: "When faced with a national security emergency situation, NERC may use one of the following special processes to develop a Reliability Standard that addresses an issue that is confidential. Reliability Standards developed using one of the following processes shall be called, "special Reliability Standards" and shall not be filed with ANSI for approval as ANSI standards." (emphasis added). The concept that certain Reliability Standards will not be filed with ANSI is not a new one to the Standard Processes Manual nor does it jeopardize NERC's accreditation. In order to address your concern regarding the potential lag in reporting to the Board of Trustees, additional language has been added to require reporting of the use of the waiver provision to the Standards Oversight & Technology Committee. In order to address your concern regarding notice to stakeholders, the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee has been incorporated. NERC, the Regional Entities and industry stakeholders have a significant mutual investment in developing a sustainable Reliability Standards program that will maintain the reliability of the bulk power system in North America. The success of the unique Electric Reliability Organization (ERO) model requires NERC to develop and maintain a body of high-quality, effective Reliability Standards. The current trajectory is unsustainable and, without considering significant course correction, the ERO and industry finds itself nearing a critical juncture where alternate methods to accomplish the development of mandatory Reliability Standards has become necessary. NERC is at risk of losing the confidence of U.S. regulatory authorities and industry executives in its ability to produce standards in a timely and efficient manner. Adding an additional 30-45 days to the standard development process in order to utilize a waiver as proposed would defeat the very purpose of the waiver provision- which is to add flexibility to the process. 15) Regarding Section 4.9, the reference to federally-recognized United States Holidays is intended to acknowledge that NERC's offices that accept and process ballot submissions, which are located in the United States, are not open on these dates. While the Standards Committee and NERC staff make every consideration possible to posting conflicts, the Standards Committee did not feel it was necessary to codify this in the SPM. Since there are several representatives on the Standards Committee from Canadian

Organization	Yes or No	Question 7 Comment
entities, they can help ensure the other members are aware of Canadian-specific conflicts of any nature. No change made.		
Consumers Energy		Consumers Energy believes that where substantive changes are made, quality review should still be performed. Though this is a time consuming process, we believe it is better than a standard which does not meet all the necessary criteria being approved, presented to FERC, then returned for additional work.
Response: The goal of quality review is to ensure that a standard presented for FERC approval meets the necessary criteria for approval. As is stated in the "rationale" box attached to Section 4.6, the changes to the language in this section are intended to ensure that quality review occurs in parallel with the development of a Reliability Standard. Section 4.6, fn 30 also states that quality review will be conducted in accordance with an approved procedure. The Standard Committee's Standards Process Subcommittee is working on improvements to the quality review procedure that will ensure quality review will occur as necessary "in parallel with the development of a Reliability Standard" to best facilitate FERC approval. While in some cases it might be advisable to conduct an additional Quality Review after substantial changes have been made to a standard there are other cases where a change, although substantive, is not substantial enough to justify the delay and resources that would be involved. For this reason we do not believe it is advisable to require an additional Quality Review after every substantive change.		
EPSA		EPSA answers:EPSA generally supports the efforts of the Standards Committee (SC) and NERC staff regarding the proposed revisions to the Standards Process Manual and votes yes on while expressing the value of improvements and concerns about the proposed revisions. It is important to incorporate the changes of the Standards Process Input Group (SPIG) and make changes that will promote continual improvement of the standards process. Several revisions should improve the standards process: - Development of RSAWs in the standards process will better align RSAWs with the intent of the standard and motivate registered entities to use RSAW provisions in compliance programs; - the revised language includes the inclusion of technical writers, legal, compliance and facilitation support personnel which will provide for appropriate professional personnel making the standards process more efficient; - removal of the 30 day time frame for informal comment periods is useful

Organization	Yes or No	Question 7 Comment
		to give flexibility to the informal process;- enabling quality reviews to occur throughout the process rather than at the end is a positive changes which should add flexibility; and, - Standard Authorization Request (SAR) remand revisions process improvement that now allow the SC to remand a SAR to either Staff or the requestor should increase efficiency.EPSA does have some concerns about the proposed changes that should be noted:- A key point raised through the SPIG evaluation process and in the comments was the need for better front end analysis. This point went in two directions - one became a Reliability Issues Steering Committee (RISC) task to consider whether an issue should be handled with a standard. The RISC is now in place and will address this issue. The second issue dealt with whether to deploy more robust input in creating the project details (scope, foundational analysis, etc.) that would better focus the standard project. In EPSA's view the second issue still needs to be addressed. Should the SPIG continue its work EPSA recommends that this issue should be the starting point for their continued work. - Another SPIG recommendation was for better utilization of the technical committees in the standards development process. The current revisions do not include effective changes regarding the role of the technical committees.- The revisions tie the SPM closely to the Reliability Standards Development Plan (RSDP). It's not clear that the plan development process is sufficient to support this strong of a tie. The RSDP process may need notable revision to be effective. Moreover, it may need coordination with the RISC efforts.- Removal of Measures from the standard language means removal of approved language that has provided registered entities with stability and provides informal guidance. The replacement of Measures with RSAWs needs to demonstrate measurable benefits, and if not, the change should be revisited.- Regarding changes associated with Response to Comments - EPSA infers that the benefit of the change is that SDT members don't have to spend as much time on responding to comments and can focus on drafting work. However, the response to comments is important - its serves as an acknowledgement, as well as whether the SDT understood the comments, and as a tool for confirming language understanding. Such clarification can inform understanding in the compliance

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		process. In addition, putting all responses at the end of the process in summary form may eliminate the value that the response to comments contributed to language development and getting to yes votes.- The waiver justification is that it will improve efficiency and expedite the standards process in place of the Expedited Process. EPSA believes that installing a broad waiver may not be as efficient as fixing the problems with the Expedited Process. The inclusion of the waiver creates a lot of latitude for the SC to potentially step aside the process that relies on stakeholder expertise for decision making. Therefore it is not assured that time will be saved through use of the waiver.

Response: Thank you for your comments of support. Regarding your particular areas of concern:

1) It is still unclear what role the RISC will play, in regards to the front end of Standards Development. Until that is understood, no changes will be made to the SPM.

2) The SPM currently contemplates utilization of the technical committees in various steps. No additional changes in this version are planned. However, a change in how the SPM is utilized is where further improvements will be seen.

3) Since the RSDP process is where modifications would need to occur, no changes have been made to the SPM. This feedback will be retained for consideration in modification of the RSDP process.

4) With regard to the comment regarding removal of measures, their exclusion in standards would occur going forward only. All existing approved measures will be retained until the next revision of the standard.

5) It is envisioned that the collaboration between Standards and Compliance will continue throughout the life of the Reliability Standard and the associated RSAW and that future revisions to either the Reliability Standard or the RSAW will maintain this relationship.

While we agree that the well crafted measures provide a level of certainty in regards to compliance obligations, we also recognize that the current format within the Standard does not lend itself to allow the SDT to clearly articulate the intent of the requirements. Eliminating the Measures from the Standard and incorporating them in to the RSAWs provides the SDT with the opportunity to provide a complete explanation of the intent of the requirements while providing guidance on how to achieve the acceptable level of compliance.

6) As you note, Section 16.0 is very similar to the currently –effective Standard Processes Manual section of the Expedited

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Reliability Standard Development Process. However, a Standard developed using the Expedited Reliability Standard Development Process is approved only on a conditional basis and it must *again* go through the standard development process in order to be made permanent. The Expedited Reliability Standard Development Process provides: **If a new or modified Reliability Standard is developed, approved by its ballot pool, and subsequently adopted by the NERC Board of Trustees through this expedited process, one of the following three actions shall occur [fn27]:** **• If the Reliability Standard is to be made permanent without additional substantive changes, then a SAR and a proposed Reliability Standard shall be submitted to the Reliability Standards staff immediately after the ballot. The project shall be added to the list of approved projects and shall proceed through the regular standard development process, including balloting by stakeholders, without any intentional delay.** **• If the Reliability Standard is to be substantively revised or replaced by a new Reliability Standard, then a project for the new or revised Reliability Standard shall be added to the list of projects to be added to the Reliability Standard Development Plan. The project shall be initiated as soon as practical after the ballot and the project shall proceed through the regular Reliability Standard development process, including balloting by stakeholders, as soon as practical but within two years of the date the Reliability Standard was approved by stakeholders using the expedited process.** **• The Reliability Standard shall be withdrawn through a ballot of the stakeholders within two years of the date the Reliability Standard was approved by stakeholders using the expedited process.** **This is clearly redundant and a waste of resources for NERC, the industry and the drafting team. Rather than repeating the standard development process, Section 16.0 would allow a Reliability Standard to become "permanent" upon stakeholder approval.**		
National Rural Electric Cooperative Association (NRECA)		General Comments:NRECA continues to have significant concerns with the new provisions in the proposed SPM. We are voting "negative" on this current ballot for several reasons. While we support moving the process forward to make improvements to the SPM, we believe there are too many unfocused and uncoordinated efforts underway today creating confusion and uncertainly on ultimately where standard development process changes are going. NRECA believes a more focused and collaborative effort, possibly through the SPIG, will lend itself to

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		a comprehensive, and not staggered or piecemeal, effort to improve the SPM. NRECA requests that consideration be given to making further revisions to the SPM as identified in our comments below in a future ballot period that is based on such a comprehensive effort. NRECA remains convinced that there is a need for a thorough analysis of the current SPM and standards development activities to clearly identify the areas that require changes to ensure standards are developed in the most efficient and effective manner. This work should be completed as soon as possible regardless of how the SPM work progresses.If the provisions in the current proposed SPM are approved by the industry, the BOT and ultimately FERC, NRECA encourages the SC and SDTs to carefully implement new provisions of the SPM. It is critically important to successful standard development that stakeholder comments are properly considered and clearly responded to, and that the new waiver provisions is utilized in very few and special cases. Specific Comments:Section 3.4 - third paragraph - The reasons that the SC can disband a SDT are quite subjective and if ever used could create unnecessary tension between the SC and stakeholders. There may be relevant reasons why a SDT may not be able to achieve industry consensus or fully address a regulatory directive. NRECA requests that items b and d be deleted.Section 3.6 - first paragraph - While this does not appear to be a proposed revision the current SPM, NRECA does not understand why NERC, and not the SC, selects interpretation drafting team members. NRECA requests that unless there are specific and necessary reasons provided for NERC to have this role, that the SPM be revised to provide this responsibility to the SC. Section 4.1 - several places throughout section - References to “retirement of a Reliability Standard” should also clearly recognize that there could be retirement of one or more requirements of a reliability standard, not always the whole standard. Wherever “Reliability Standard” is mentioned regarding a SAR, the SPM should also recognize that it may not always be a standard, but that it could be a definition.Section 4.1 - seventh paragraph that lists the SC options for decision on a SAR - In the second bullet, if the SC remands a SAR, NRECA believes it should be required to provide a written explanation similar to what is listed in the third bullet. This should be revised in the SPM. Regarding the

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		third bullet, allowing the SC to reject a SAR for "good cause" seems to provide unnecessary flexibility for the SC. NRECA requests that basic high level criteria be developed for the SC to use for rejecting a SAR.Section 4.14 - first paragraph - Towards the end of the paragraph, the word "substantive" is used, but it appears that word should be "significant" in order to work with the language earlier in the paragraph.Section 4.19 - second paragraph - In the second line NRECA is concerned that only the SC or NERC staff is permitted to identify the need to retire a standard. This should be able to be done by anyone - the SC, NERC, REs and stakeholders - that can submit a SAR. Also, there should be recognition that only a requirement of a standard, not only the whole standard, may be requested for retirement. Lastly, the reference to the Bulk Power System should be changed to Bulk Electric System.

Response:

Thank you for your comments of support. Regarding your particular areas of concern:

1) With respect to the comment on section 3.4, although the reasons listed are to some extent subjective, it is important that the SC have flexibility in making this decision. Although as you commented there may be relevant reasons for a SDT not to be able to reach consensus or to fully address a regulatory directive, the inability of the SDT to achieve those critical objectives might still be a sufficient reason for the SC to disband a drafting team. Note that the language is permissive not mandatory, so the SC can use its judgment in such cases to determine whether disbanding a team is the best alternative available. No change made.

2) The selection of an interpretation drafting team was not revised in this version of the SPM. While this comment is not in scope for consideration in this version, the issue will be retained for future consideration. [Stacey is researching this to find out the background on why NERC selects Interpretation teams, and not the SC. I know this was a deliberate decision…]

3) With regard to the comment regarding the retirement of a requirement as opposed to an entire Standard. We believe that retiring a requirement is clearly a modification of a standard which is already directly addressed by the SPM. Similarly, this same process would also be applicable to retire an individual requirement. No change made.

3) The suggestion to recognize definitions, along with standards, is appreciated. The SPM will be edited to acknowledge both Standards and definitions where appropriate.

4) We agree with the suggestion to require a written explanation if the SC remands a SAR in Section 4.1. The second bullet point

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will be revised to read: "Remand the SAR back to the requestor or to NERC Reliability Standards Staff for additional work. If the SAR is remanded, the Standards Committee will include a written explanation of what additional work is requested. 5) With respect to the comment regarding Section 4.1 and criteria for rejecting a SAR, we believe that in light of the fact that a written explanation of the rejection, coupled with the right to appeal in Section 8, there is a sufficient check on any inappropriate use of this authority. No change made. 6) We agree that the term "substantive" in the first paragraph of Section 4.14 seems inconsistent with the usage of the terms "significant" and "insignificant" in the preceding text. However, the word "substantive" appears to be appropriate. Instead, Section 4.14 will be edited to replace the words "significant" and "insignificant" with the words "substantive" and "non-substantive". 7) The commenter is correct that anyone is permitted to propose retirement of a standard. The suggested edit is accepted. The words "by the Standards Committee or NERC Staff" will be deleted from Section 4.19. 8) With respect to the comment advocating the use of BES in place of BPS, the use of BPS was derived from its use in the statutory authority under which the ERO operates. No change made.		
Arizona Public Service Company		In spite of SPIG recommendation to address cost effectiveness in the standard development process (Recommendation 4, bullet item 2), the proposed process does not address this recommendation. This should be one of the prime considerations and should be addressed.
Response: The SPIG recommendation to address cost effectiveness in the standard development process is being addressed outside of the revisions to the SPM in two ways: 1) In the short term, two standard questions regarding potential costs of a proposed standard are being added to the SAR comment form; 2) in the longer term, the Standards Committee's Standards Process Subcommittee has developed a "Cost Effectiveness Analysis Procedure" or "CEAP" that has been posted for, and received industry comment. The CEAP is a guideline intended to supplement the standards development process by gathering and reporting high-level cost effectiveness feedback from the industry during standard development without adding significant delay to the development process. The CEAP process will be piloted in the near future on an experimental basis to determine whether it adds value and ensure it does not create undue delay in standards development. It is premature to add the CEAP to the SPM at this time, but the Standards Committee will evaluate the CEAP Pilot and may in the future consider changes to the SPM related to		

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the CEAP.		
Kansas City Power & Light		Kansas City Power & Light endorses the comments made by EEI on this subject.
Response: Thank you for your comment.		
Edison Electric Institute		On behalf of our member companies, the Edison Electric Institute (EEI) appreciates the opportunity to provide the following brief comments on the process changes being considered in conjunction with recommendations made by the Standards Process Input Group (SPIG). EEI looks forward to significant process efficiency gains as a result of the full implementation of the SPIG recommendations.Section 16: Waiver ProvisionThis is unnecessary. Full implementation of SPIG recommendations will eliminate need for waiver of any standards development process steps. As a general matter and to correctly align various responsibilities, EEI supports full ownership of the technical content of standards development projects by the various drafting teams and stakeholders through comments and balloting, and process oversight by NERC management. In comments to SPIG, EEI asked that the confusion over process oversight be resolved once and for all. NERC has the responsibility to deliver proposed standards to FERC and should have the tools to ensure timely responses.If problems develop that challenge timely project completion, drafting teams and NERC management need to efficiently resolve the matters. In addition, EEI envisions much stronger and more disciplined process oversight than has been practiced in some projects in the past, which should eliminate the problem. Instead of anticipating such a problem, EEI challenges NERC and all stakeholders to make strong commitments to develop and execute plans that define specific milestones and deadlines that ensure timely development. Waiving process steps for 'insubstantial' matters is a slippery slope that NERC should avoid. Moreover, there is case precedent that NERC has filed with FERC various 'minor modifications' that were not returned to the standards development process for balloting. The boundary for determining 'insubstantial' should be carefully considered and clarified from legal and regulatory perspectives before a final decision is made.Operations Sanctions

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		TableAs part of its April 2012 report, SPIG recommended that “redundancies” such as VSLs be eliminated. In response to this recommendation, as part of the Standards Committee Process Subcommittee (SCPS) white paper issued in June, the SCPS agreed with the elimination of VSLs but also suggested the elimination of VRFs from standards in favor of a “sanctions table”. The SCPS proposed that this sanctions table would replace the existing base sanctions table contained in the Compliance Monitoring and Enforcement Program (CMEP) manual.EEI understands that the proposal framed in the NERC process subcommittee ‘white paper’ and the proposed draft process manual to be that VRFs and VSLs would no longer be defined as ‘essential elements’ of a standard, but would remain part of the standard development project. Under the proposed Standards Process Manual, it appears that the drafting team will work with NERC staff in developing a set of VRFs and VSLs that will be subject to a non-binding poll. Ultimately, the VRFs and VSLs will be presented to the Board of Trustees for adoption. On the surface, the draft proposed Standards Process Manual would appear to agree with the underlying process efficiency objective. However, the proposal is confusing for several reasons. First, contrary to the SPIG recommendation to remove only VSLs as redundant and the SCPS recommendation to eliminate both VRFs and VSLs, the proposed Standards Process Manual states that VSLs and VRFs will still be developed, but will be developed in parallel with the drafting team project scope. Thus, this proposal does not appear to create more efficiency. Further, we do not see a clear alternative process proposal for the development of VSLs and VRFs, and it is important to have an understanding of where and how these variables will be defined.Second, SPIG did not recommend the development of a sanctions table. The purpose of these proposed changes is to address SPIGs recommendations, not to confuse and complicate the process by retaining both VSLs and VRFs and adding the new SCPS-proposed sanction table. While we understand that there have been informal discussions on developing such a table, the addition of this material to the SPIG project does not fit with our sense of ‘eliminating redundancies.’ In addition, the white paper seems to conflate the VSL/VRF process issue with the development of the sanctions table. Certainly, SPIG

Organization	Yes or No	Question 7 Comment
		did not recommend the development of a sanctions table. Therefore, because the proposed Standards Process Manual fails to clearly address SPIG's concerns regarding VSLs, there is a lack of clarity regarding how VSLs and VRFs will be developed and there is uncertainty regarding the sanctions table, EEI recommends that the sanction table not be adopted and the VSLs remain in place until further clarification can be provided by SPIG as to how to address this issue.Handling 'No' VotesThe handling of 'no' votes is a matter that has attracted significant attention. SPIG recommended that the ballot process should use all votes to establish quorum, and provide options for 'no' votes, including changes to the balloting and commenting process that would help useful comments. For example, many comments will briefly state a broad negative comment without showing the specific language of concern, or offering a constructive alternative that the commenter could support.The proposed process change is to disallow simple 'no' votes without comments for purposes of determining final ballot counts. EEI does not understand the logic that moves from the SPIG recommendations to the process proposal to disallow simple 'no' votes, and cannot support the proposal.We understand that SPIG seeks to move the process in the direction of having the balloting and commenting process to provide as much substantive feedback as possible. Irrelevant comments or negative votes unaccompanied by comments do not offer helpful feedback, however, it should be a relatively simple matter to address such comments very quickly. EEI recommends that appropriate software changes be designed and implemented as soon as possible that will help gather more focused comments. A simple 'no' vote should be allowed to count both for determining quorum and final ballot count. Finally, somehow we need to find a way to work around the apparent timing issues for making necessary software changes. This should not be a binding constraint on making these important process changes.

Response:

Thank you for your comments.

1) Respectfully, we suggest that in order for the ERO model to be successful, NERC must have the ability to meet regulatory

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		deadlines. Pursuant to section 215(d)(5) of the FPA, the Commission may direct the ERO to submit to the Commission a new or modified Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Standard appropriate to carry out section 215. As the ERO, NERC must be able to comply with a Commission directive pursuant to section 215(d)(5) of the FPA. The Commission has expressed concern that the standard development process can be misused to "delay or block NERC's ability to report to a Commission directive" *See North American Electric Reliability Corp.*, 130 FERC ¶ 61,203 at P 23 (2010). The Commission has continuously expressed concern regarding the amount of time it takes to develop a Reliability Standard. • *See North American Electric Reliability Corp.*, 118 FERC ¶ 61,030 at P 31 (2007)("Both in Order No. 672 and in the *Certification Order* we expressed concern with the length of time the ERO process takes to develop a Reliability Standard. The ERO has never, to our knowledge, developed a Reliability Standard under its normal process in four months or developed an urgent action Reliability Standard in 60 days."). • *North American Electric Reliability Corp. Reliability Standards Development et al.*, 132 FERC ¶ 61,217 (2010)("In its application for certification as the ERO, NERC indicated that under its usual ANSI-accredited process in effect at the time, a Reliability Standard may be developed in as little as four months, or up to 12 to 15 months for a more complex Standard. However, the NERC analysis submitted in this docket indicates that, in practice, it has taken considerably longer, an average processing time of 21.7 months, to develop Reliability Standards. The average processing time is even longer if 'urgent action' Standards are not considered. Given this analysis, the Commission continues to have some concerns regarding NERC's ability to timely develop Reliability Standards.")(internal citations omitted). NERC, the Regional Entities and industry stakeholders have a significant mutual investment in developing a sustainable Reliability Standards program that will maintain the reliability of the bulk power system in North America. The success of the unique Electric Reliability Organization (ERO) model requires NERC to develop and maintain a body of high-quality, effective Reliability Standards. The current trajectory is unsustainable and, without considering significant course correction, the ERO and industry finds itself nearing a critical juncture where alternate methods to accomplish the development of mandatory Reliability Standards has become necessary. NERC is at risk of losing the confidence of U.S. and Canadian regulatory authorities and industry executives in its ability to produce standards in a timely and efficient manner. 2) The Sanctions Table concept was developed as a replacement to the Penalty Matrix which utilizes the VRFs and VSLs. The SCPS recognized that elimination of the VRFs and VSLs required that a viable alternative be developed to replace the Penalty Matrix.

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Based on the majority of the comments received to the initial posting of the draft process document, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. **The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects, and will consider suggestions provided in the comments below as part of that consideration. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.** **3) Participation in the NERC Ballot Pools comes with responsibility to actively participate and be helpful to the process. The value of any comment during the process cannot be underestimated and it is imperative to the NERC Standard Drafting Teams that they know why the entities voted negatively. The drafting teams need this information and the industry needs to be encouraged to provide constructive comments in order to move the standards forward in an efficient manner. The current standards productivity is not meeting the expectations of the regulators and it is important that the drafting teams be given as much information as possible, especially information on why entities voted negatively, to develop standards efficiently and expeditiously. It is burdensome for the drafting teams to continually revise standards to try to gain industry consensus when they don't have all the concerns. The identified shortcomings of the NERC software has been communicated by NERC Standards Committee to NERC staff as suggestions for potential revision to the existing balloting software.**		
Detroit Edison		On page 7- definition of a Reliability Standard- change the wording of the beginning of the first sentence to read- a document containing one or more requirements to provide for the Reliable Operation of the Bulk Power System. REMOVE the following- including without limiting the foregoing, requirements for the operation of existing Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any

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		requirement to enlarge Bulk Power System Facilities or to construct new transmission capacity or generation capacity. Leave the last sentence about FERC approval.
Response: The definition of "Reliability Standard" as worded in Section 2.1 is the approved definition that appears in Appendix 2 to the NERC Rules of Procedure, Definitions Used in the Rules of Procedure, which is based on the statutory definition of the term in Section 215 of the Federal Power Act. Accepting the proposed revision to the SPM would create a discrepancy with the approved definition for use in the Rules of Procedure, and will not be adopted. If you believe a change to the defined term is required, please submit a request to change the definition in Appendix 2 of the NERC Rules of Procedure.		
NextEra Energy		One part of the Standards Development process that needs significant improvement is the options available to the Standards Committee when reviewing a proposed SAR. Currently, the rules related to a SAR, even with the new SPIG language, state that the Standards Committee essentially has only the choice to accept or reject, with some ability to delay for further justification or work. NextEra believes that the Standards Committee should consider a SAR in light of existing or pending Standards Development projects, stakeholder support for the SAR and the new RISC triage group. To implement these options, NextEra requests that pertinent portions of Sections 4.1 and 4.2 be revised to read as follows: Section 4.1 proposed changes:"The NERC Reliability Standards Staff shall review each SAR and work with the submitter to verify that all required information has been provided. All properly completed SARs shall be submitted to the Standards Committee for action at the next regularly scheduled Standards Committee meeting. When presented with a SAR, the Standards Committee shall determine if the SAR is sufficiently complete to guide Reliability Standard development and whether the SAR is consistent with this manual. The Standards Committee shall take one of the following actions: o Accept the SAR. o Accept the SAR with the condition that it be combined with an existing or pending Standards Development project. This action may require that the Standards Committee also authorize increasing the scope of the existing or pending Standards Development project. o Remand the SAR back to the requestor or to NERC Reliability

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		Standards Staff for additional work. o Reject the SAR. The Standards Committee may reject a SAR for good cause. If the Standards Committee rejects a SAR, it shall provide a written explanation for rejection to the sponsor within ten days of the rejection decision. o Delay action on the SAR pending one of the following: (i) development of a technical justification for the proposed project; or (ii) consultation with RISC, the Planning Committee or Operations Committee to determine if there is another approach to addressing the issue raised in the SAR, such as via lessons learned, best practices technical white paper, etc."Section 4.2 proposed changes:"If stakeholders indicate support for the project proposed with the SAR, the drafting team shall present its work to the Standards Committee with a request that the Standards Committee authorize development of the associated Reliability Standard. When considering this request, the Standards Committee may take any of the appropriate actions listed in Section 4.1. If stakeholders do not support the project proposed with the SAR, the drafting team shall present its work to the Standards Committee. If the Standards Committee agrees that stakeholder support is lacking, the SAR shall be rejected and the proposed project closed. When there is a question of stakeholder support for a SAR (either from NERC staff or a Standards Committee member), the Standards Committee shall review the record and make a determination. If the determination is that there is no stakeholder support for the SAR, the SAR shall be considered rejected and the proposed project closed."New language to by-pass SAR process at the end of Section 4.1:"Upon receipt of a rapid revision request, the Standards Committee may authorizing by-passing of the SAR process, provided that the rapid revision request includes specific language to change a Reliability Standard to improve its clarity or a possible incorrect interpretation, and the change shall be supported with legal or technical rationale. If the Standards Committee does not agree that a rapid revision request is appropriately supported by technical or legal rationale, it shall reject the rapid revision request and inform the requester in writing."
Response: The SPSC agrees that SARs should be considered in light of existing or pending projects. The suggested edits to Section		

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4.1 and 4.2 are accepted to add clarity to the process. **Regarding the proposed changes to Section 4.2, the Standards Committee is currently exploring whether there should be additional process(es), further guidelines and/or criteria for various Standards Committee decision points within the SPM such as acceptance rejection of a SAR or other drafting team output, when and how to terminate a standards development project, etc. This may be addressed a process documents or guidelines that support, but are not part of the SPM, or may be addressed in future revisions to the SPM. This matter is not ripe for inclusion in the current revision of the SPM; however, your comment is noted and will be considered during the ongoing work of the Standards Committee.** **With respect to the comment advocating new language to by-pass the SAR process for rapid revision requests, the Standards Committee Process Subcommittee has considered this issue. At this time, we feel that a SAR is necessary to establish the framework of the project and to ensure "scope creep" does not occur.**		
Manitoba Hydro		Overall, it is still not clear to us that these revisions have addressed SPIG recommendations #4 and #5. Section 2.5: Requires revision if it is to apply to jurisdictions outside of the United States. The reference to the term "Compliance Enforcement Authority" should be revised to refer to the entity that is responsible for monitoring performance and/or determining if an entity is compliant with the associated Reliability Standard. A similar revision needs to be made to the next sentence (by changing "and" to "and/or") as neither NERC nor Regional Entities determine compliance in Canadian jurisdictions.Section 3.7: "Canadian National Energy Board" should be renamed "National Energy Board of Canada".Section 4.9: Given that NERC is an international organization, this section should refer to both U.S. and Canadian holidays in considering the ballot window.Section 4.19: The reference to "FERC" in the first sentence should be replaced with "Applicable Governmental Authorities".The term "applicable governmental authority/ies" should be capitalized throughout, as it is a defined term.
Response: Regarding Section 2.5, the term "Compliance Enforcement Authority" in this section of the SPM aligns with the defined term that appears in Appendix 2 to the NERC Rules of Procedure, Definitions Used in the Rules of Procedure. Accepting the proposed revision to the SPM would create a discrepancy with the approved definition for use in the Rules of Procedure, and will not be adopted. If you believe a change to the defined term is required, please submit a request to change the definition in		

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Appendix 2 of the NERC Rules of Procedure. **Regarding Section 3.7, the proposed edit is accepted. The language will be changed to "National Energy Board of Canada."** **Regarding Section 4.9, the reference to federally-recognized United States Holidays is intended to acknowledge that NERC's offices that accept and process ballot submissions, which are located in the United States, are not open on these dates. While the Standards Committee and NERC staff make every consideration possible to posting conflicts, the Standards Committee did not feel it was necessary to codify this in the SPM. Since there are several representatives on the Standards Committee from Canadian entities, they can help ensure the other members are aware of Canadian-specific conflicts of any nature. No change made.** **Regarding Section 4.19, the proposed edits are accepted. "FERC" will be replaced with "Applicable Governmental Authorities". The term "Applicable Governmental Authorities" will be capitalized throughout the document as a defined term.**		
PacifiCorp		PacifiCorp believes that further contracting the limited time that the industry already has to review, evaluate, and comment on new or revised reliability standards does not adequately address the challenges associated with reaching timely stakeholder consensus. Rather than focusing on the small window of opportunity that the industry has to provide input into the process, attempts should be made to curtail the amount of time it takes for standards to be processed by the drafting committees.
Response: Thank you for your comment. The NERC Standards department has recently undergone reorganization with the intent to shift a substantial amount of their focus from process to product. One of their primary goals is to facilitate more work in between drafting team meetings, thereby increasing the team's pace and output.		
Pepco Holdings Inc		PHI supports the proposed draft of the SPM.
Response: Thank you for your comment.		
FirstEnergy		Recommendation #5 states that in part "Formal and consistent project management".FE agrees that this is the key to an efficient process and the NERC Staff will improve. but it is not clear in the SPM as to how this will be accomplished? WIll there be specific projct management tools provide to NERC Staff?FE believes that in Section 2.5 Elements of a Reliability Standard should include as on one the

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		components the Version History of a Standard. This would be useful information for determining the changes/revision between versions of a standard.
Response: NERC has announced several steps to improve its project management capabilities including a reorganization of that area. Changes in the guidelines for SDTs have also been made to better define the roles of the chair and NERC staff in the process. The SCPS believes that inclusion of such detailed information in the SPM is inadvisable because it would limit the flexibility of NERC, the Standards Committee and the industry in continuing to tune the process to improve its efficiency and flexibility. No change made. **The recommended edit to Section 2.5 is accepted. In practice, all standards currently include the version history, thus it is useful to indicate in the SPM that version history is a component of a standard.**		
Southern Company		Southern Company supports the Standards Process Input Group (SPIG) Recommendations and the Standards Committee's efforts to incorporate into the SPM various revisions proposed by the SPIG and the Standards Committee Process Subcommittee (SCPS). We have reviewed two versions of SPM Revisions and noted where the Standards Committee has given careful consideration to formal comments from industry. We are however concerned that there are several key and significant changes poised for implementation and that at this juncture, incremental steps are necessary to ensure that NERC and stakeholders achieve the desired results. Our comments cover several proposed changes to the SPM and are indicative of the fact that it is critical that all stakeholders understand what effect the revisions will have on the processes throughout the ERO enterprise and not just to those described within the Manual. We appreciate your consideration of our comments.The currently effective SPM (and the proposed draft SPM) does not demonstrate how, if invoked, Rule 321 would be implemented. The draft SPM only mentions Rule 321 in the context of a Reliability Standard's ability to be enforced for compliance purposes (see draft Section 4.17: Compliance). We raise this concern - that the Standards Committee should address how this rarely used, but nonetheless important rule would be implemented - as a matter which is separate and apart from the concerns expressed with the new waiver or deletion of the expedited process. The draft SPM

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		(including the waiver provision) does not maintain certain key aspects of the expedited process. More specifically, the current SPM explains how an "expedited" standard could either be made permanent, or routed through the regular process, or withdrawn. This explanation was spelled out in the now-deleted 'Expedited' process section and should be restored.The Standards Committee should clarify its procedures for disbanding a drafting team and which subsequent activities the Committee will take to efficiently advance the work effort into the next developmental phase. The proposed revisions do not demonstrate that adequate procedures will be in place to ensure that appropriate checks and balances are applied to both the Standards Committee and any subsequent committee or team that may be tasked with the work effort. More specifically, the revised SPM does not explain if it must provide any notice to the Board of Trustees prior to taking such action or after it has already disbanded the drafting team. Also, the SPM does not indicate if the reason for disbanding the team correlates to invocation of a specific rule (e.g. Rule 321). Finally, the SPM does not discuss what level of review will be undertaken to assess whether or not the subject work effort should proceed. In other words, it is not clear if the Standards Committee will conduct a threshold assessment of whether or not the disbanded team and work effort is still required to address an outstanding reliability issue.At the Introduction Section (and at Section 4.10), the draft SPM should be clarified to avoid any confusion over the summation of the number of votes cast for approval of a proposed Reliability Standard, definition, Variance, or Interpretation. The draft language is silent with respect to affirmative votes without comments. The draft language is as follows: "A two-thirds majority of the weighted Segment votes cast shall be affirmative. The number of votes cast is the sum of affirmative and negative votes with comments, excluding abstentions, non-responses, and negative votes without comments." Either of the following revisions may alleviate the concern. Option A - "A two-thirds majority of the weighted Segment votes cast shall be affirmative. The number of votes cast is the sum of all affirmative votes and all negative votes with comments, excluding abstentions, non-responses, and negative votes without comments." Option B - "A two-thirds majority

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		of the weighted Segment votes cast shall be affirmative. The number of votes cast is the sum of negative votes with comments, affirmative votes with or without comments, excluding abstentions, non-responses, and negative votes without comments." At Section 2.1: Definition of a Reliability Standard, the following phrase provides key reference information about the definition's placement in the Rules of Procedure but the reference should be incorporated as a footnote. "See Appendix 2 to the NERC Rules of Procedure, Definitions Used in the Rules of Procedure."At Section 2.5: Elements of a Reliability Standard, the phrase below creates ambiguity over what are (or are not) components of a Reliability Standard. "The components of a Reliability Standard may include the following:..." It seems more appropriate to use more definitive language such as "...shall include..." These modifications clarify the elements of a Reliability Standard. Other comments to this revision suggest that footnote 4 be deleted as a means to mitigate misunderstanding over the stakeholder's role in development of VRFs and VSLs.The Standards Committee should revisit certain section and subsection titles. The main section title and subsection title should not be identical (refer to Section 2.0 and Subsection 2.5).Certain modifications at Section 3.6: Drafting Teams will clarify the flexibility allowed in the formation of drafting teams constituted for the various purposes described in the first paragraph of this section. More specifically, the addition of the phrase "as deemed appropriate" throughout the paragraph will establish flexibility for the Standards Committee and NERC Reliability Standards Staff. It may be necessary to make corresponding modifications to Section 4.3 of the SPM and to the Drafting Team Guidelines mentioned in footnote 12.At Section 4, Figure 1, Quality Review was removed from Step 4 and added to Step 3. This implies that the only opportunity for a Quality Review is at the initial posting prior to collecting informal feedback. Is this correct? Also, the revised illustration consolidates comment period and ballot "iterations" where the steps may be repeated multiple times (as required). We note that the consolidated steps do not include a Quality Review. We are not certain if the exclusion is a simple oversight in the drafting process. At Section 4.1: Posting and Collecting Information on SARs, Paragraph 3, it is not clear what constitutes

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		"substantially revised" Reliability Standards. This should be clarified or addressed in some manner.The third paragraph at Section 4.3: Form Drafting Team, should be made consistent with section ## in that both are consistent with respect to the availability and inclusion of legal and compliance resources. Also, prior comments at Section 3.6 suggest that modifications are helpful for ensuring consistency and flexibility in constituting drafting teams.See prior comments at the Introduction section for modifications which address summation of the consensus vote.

Response: Thank you for your comments of support. Regarding your particular areas of concern:

1) We feel that the inclusion in the SPM of how Rule 321 may be invoked is out of scope at this time. Furthermore, we do not believe that such clarification would contribute to the overall improvement of the SPM, nor addresses a SPIG recommendation. No change made.

2) Certain aspects of the former expedited process were not ANSI requirements and were intentionally removed. In particular, the requirement to revisit a standard developed under the expedited process was creating additional work for the industry, when those resources could instead be dedicated to other efforts.

3) To clarify, under the SPM as proposed, the Board would not have to be notified prior to disbanding a drafting team. The SC is responsible for managing drafting teams. The Standards Committee is currently exploring whether there should be additional process(es), further guidelines and/or criteria for various Standards Committee decision points within the SPM such as acceptance rejection of a SAR or other drafting team output, when and how to terminate a standards development project, etc. This may be addressed a process documents or guidelines that support, but are not part of the SPM, or may be addressed in future revisions to the SPM. This matter is not ripe for inclusion in the current revision of the SPM; however, your comment is noted and will be considered during the ongoing work of the Standards Committee.

4) The Standards Committee is currently exploring whether there should be additional process(es), further guidelines and/or criteria for various Standards Committee decision points within the SPM such as acceptance rejection of a SAR or other drafting team output, when and how to terminate a standards development project, etc. This may be addressed a process documents or guidelines that support, but are not part of the SPM, or may be addressed in future revisions to the SPM. This matter is not ripe for inclusion in the current revision of the SPM; however, your comment is noted and will be considered during the ongoing work of the Standards Committee.

5) We agree with your comment regarding necessary modifications in the Introduction Section and Section 4.10 to better clarify

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		what votes are counted to determine approval. Clarifying changes have been made. 6) Regarding Section 2.1, thank you for your editorial comment; however, the SCPS does not believe it is necessary to move the reference to the Rules of Procedure to a footnote at this time. 7) FERC has held that only the Requirements and Applicability components of a standard are enforceable. While not required, the other components of a Reliability Standard listed in Section 2.5 are important for a complete understanding of the standard. To make clear that all of the listed components should be included in a draft standard without suggesting that they are all "required", Section 2.5 will be edited to remove the word "may". The phrase will read as follows: "The Components of a Reliability Standard include the following. . ." 8) Footnote 5 (Previously Footnote 4) has been revised to address the commenters concern as follows: [5]It is the responsibility of the ERO staff to develop compliance elements for each standard; these elements are not ~~technically~~ part of the standard but are included in the standard and referenced in this manual because the preferred approach to developing these elements is to use a transparent process that leverages the technical and practical expertise of the drafting team and ballot pool. If directed by FERC, NERC may file revisions to compliance elements following approval of the NERC Board of Trustees. 9) Thank you for your editorial comment; however, the SCPS does not believe it is necessary to alter the section and subsection headings at this time. The section and subsection numbers provide adequate clarity. 10) With respect to your comment on section 3.6, we feel the language is adequate. Additional softening of the language, as suggested, might lead to a perception that appointing a drafting team is entirely optional. No change made. 11) The intent of the proposed changes to Section 4.6 of the SPM was to expand the ability to conduct quality review in parallel with the standards development process and to allow flexibility to conduct quality review multiple times as the standard continues to develop. This may not be accurately reflected in Section 4's Figure 1. Figure 1 will be modified to make clear that quality review may begin at stage three, but may continue as needed during the remainder of the project. 12) With respect to your comment on the subjectivity of the addition of the words “or substantially revised” to describe SARs for which technical justification is required, we agree that the term is subjective; however, we don’t feel that it is possible at this time to adequately define hard criteria to define modifications to standards that are substantial enough to require technical justification. At this point in time we believe the best course is to provide the SC with the flexibility to make that decision, subject of course to the appeals process provided in Section 8. The following clarifying modifications have been made to the 3rd paragraph: a) added “or substantially revised” after “new” in the second paragraph, and b) clarified that the SC makes the

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determination. **13) The suggested edit to Section 4.3 is accepted. A sentence indicating that the team will also be supplemented with legal and compliance resources will be added.**		
Tacoma Power		Tacoma Power does not have any additional comments at this time. We thank you for the opportunity to provide comments and your consideration of our comments.
Response: Thank you for your comment.		
Exelon Corporation and its affiliates		Thank you for the opportunity to comment on the SPM revisions. Exelon voted affirmatively in the ballot, though as indicated by the comments, concerns remain over the revisions. Exelon's affirmative position comes from a strong desire to support the efforts of the Standards Committee and to support the pursuit of improvement to the standards development process. Exelon recognizes that some of the proposed revisions are positive: o Professional personnel - The revised language states the inclusion of technical writers, legal, compliance and facilitation support personnel. While this change in practice may have been available without the language revision, it did not occur in practice and the formal commitment to is a positive step. o Quality Review - Enabling quality reviews to occur throughout the process rather than at the end is a worthwhile flexibility so long as the SC procedure is not overly cumbersome and that other requirements for in process QR do not get in the way of standard development progress. o SAR Remand - The revisions make a process improvement to allow the SC to remand a SAR to either Staff or the requestor. These are good housekeeping improvements. However, Exelon has concerns in addition to those noted in the other questions above: o Better front end analysis - A key point raised through the SPIG evaluation process and in the comments was the need for better front end analysis. Deploying more robust input in creating the project details (scope, problem statement, foundational analysis, etc.) on which a standard project should begin could pre-empt confusion about the project objectives and avoid mission creep. A clear mission at the start saves time on

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		development. There is no change made to improve front end quality of the standard project foundations. o Role of Technical Committees - Another recommendation was for better utilization of the technical committees in the standards development process. The Standards Committee is limited to non-technical evaluations of technically dense standards projects. The revisions include no effective change for the role of technical committees. o Role of the RSDP - The revisions tie the SPM closely to the Reliability Standards Development Plan (RSDP). It's not clear that the plan development process is sufficient to support this strong of a tie. The RSDP process may need notable revision to be effective. As well, the RSDP may need coordination with the RISC efforts.The critical, overarching concern is that multiple efforts are underway related to standards development process improvements. This piecemeal approach risks creating more problems than improvements. In addition to the proposed SPM revisions the following other activities are underway: o The RISC is just beginning to formulate its functions both overall and in relation to standards development and the Standards Committee. o In August, the BOT tasked the SPIG to perform a phase 2 project on standards development. o In late August, NERC reconstituted the Standards and Compliance department staff with a fresh slate of employees new to NERC standards development. o At the October SC meeting, the SC added to its work development of a Standard Committee Strategic Plan and a work plan.SPM revisions are only one component of the many changes around standards development under consideration. It is more efficient to coordinate all the efforts into a single, comprehensive revision to be implemented once.In addition, while the amount of time it takes to develop a standard is cited as the primary aspect in need of improvement this approach fails to recognize that not all standards projects are the same (some will and should take more time than others) and quality should never be sacrificed for timeliness. Finally, by focusing on changing the SPM process, the SC misses the opportunity to recognize that it's not necessarily the process that is problematic, but how the projects are managed (and in ways mismanaged). There are many different ways to develop a standard under the same process. No doubt there is room for improvement in the process, in particular if

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		impediments exist that prevent efficiencies. However, in evaluating and revising the process without considering the implementation of the process, the improvement results may be limited. You may find that the revisions do not achieve the desired goal because they do not go to the root cause for the delays.While Exelon voted affirmatively in the ballot, the strong preference is that the SC work with the SPIG to consider SPM revisions as a piece of the other potential standards development revisions under consideration.

Response:

Thank you for your comments of support. Regarding your particular areas of concern:

1) Regarding your comment on better front end analysis - Many of the proposed modifications to the SPM were made to encourage more front end analysis and consensus building. (Such as more informal commenting, technical support, etc.) However, we agree more improvements should be made. The Standards Committee is currently exploring additional enhancements in this area. This may be addressed in either a process document that supports, but is not part of the SPM, or may be addressed in future revisions to the SPM. This matter is not ripe for inclusion in the current revision of the SPM; however, your comment is noted and will be considered during the ongoing work of the Standards Committee.

2) The SPM currently contemplates utilization of the technical committees in various steps. No additional changes in this version are planned. However, a change in how the SPM is utilized is where further improvements will be seen.

3) Regarding the role of the RSDP, we feel that the current RSDP process is sufficient. However, the extent to which the Standards Committee utilizes this process should be re-evaluated. No changes to the SPM are being made at this time, but this issue will be considered by the Process Subcommittee.

4) With respect to your comment regarding multiple efforts we agree that coordination of efforts is important to the success of the process and the SCPS is very supportive of improved coordination of the various initiatives you mentioned. However, at the same time we are obligated to respond to the clear and unambiguous direction of the SC and the NERC Board to move forward with the proposed revisions as quickly and efficiently as possible. Note that additional revisions will likely be made and that in all cases the SCPS is committed to coordinating with all affected groups.

5) With respect to your comment that the focus should not be on changing the SPM process, please note that the proposed revisions are only one aspect of the changes being made. NERC staff are separately pursuing improvements to project

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management. In addition, the Standards Committee and the Process Subcommittee are currently exploring new or modifications to existing "implementing" processes and procedures to find better ways to manage the projects and teams. Your comment is noted and will be considered during the ongoing work of the Standards Committee and Process Subcommittee. **6) With respect to your comment that the SC should work with the SPIG to consider SPM revisions as a piece of the other potential standards development revisions under consideration, we can confirm that this is already being done. Note as an example, the CEAP cost effectiveness initiative that is being undertaken outside of the SPM.**		
The United Illuminating Company		The discrepancy between the ROP Section 309 requirement for an expedited action procedures and the SPM removal of the Expedited Standard Development Process section should be resolved or explained prior to approving the SPM. The ROP and the history of the SPM make clear that an Expedited Standard Development Process was required at the time of SPM drafting. Section 309 is titled Directives to Develop Reliability Standards under Extraordinary Circumstances; it is not just a Directive to develop a Standard but a Directive issued under extraordinary circumstance. A process to waive portions of the normal standard development process is not the same thing as establishing a process to expedite standards during extraordinary circumstance. Either the ROP requires modification to remove the use of an expedited standards development process, or the section titled waivers needs to incorporate explicitly a reference to an expedited standards development process, or the expedited section not deleted. UI suggests that the Expedited Section not be deleted but that it is repurposed to meet its true intent of Extraordinary Circumstances where the BOT approves development of a Standard to be effective until a=the ANSI process can be completed. In this manner the ROP does not require modification, the proposed section 16 can be established to improve efficiencies, and the extraordinary circumstance can be retained.
Response: Thank you for your comments. As you note, Section 16.0 is very similar to the currently –effective Standard Processes Manual section of the Expedited Reliability Standard Development Process. However, a Standard developed using the Expedited Reliability Standard Development Process is approved only on a conditional basis and it must *again* go through the standard		

Organization	Yes or No	Question 7 Comment
development process in order to be made permanent. The Expedited Reliability Standard Development Process provides: **If a new or modified Reliability Standard is developed, approved by its ballot pool, and subsequently adopted by the NERC Board of Trustees through this expedited process, one of the following three actions shall occur [fn27]:** **• If the Reliability Standard is to be made permanent without additional substantive changes, then a SAR and a proposed Reliability Standard shall be submitted to the Reliability Standards staff immediately after the ballot. The project shall be added to the list of approved projects and shall proceed through the regular standard development process, including balloting by stakeholders, without any intentional delay.** **• If the Reliability Standard is to be substantively revised or replaced by a new Reliability Standard, then a project for the new or revised Reliability Standard shall be added to the list of projects to be added to the Reliability Standard Development Plan. The project shall be initiated as soon as practical after the ballot and the project shall proceed through the regular Reliability Standard development process, including balloting by stakeholders, as soon as practical but within two years of the date the Reliability Standard was approved by stakeholders using the expedited process.** **• The Reliability Standard shall be withdrawn through a ballot of the stakeholders within two years of the date the Reliability Standard was approved by stakeholders using the expedited process.** **This is clearly redundant and a waste of resources for NERC, the industry and the drafting team. Rather than repeating the standard development process, Section 16.0 would allow a Reliability Standard to become "permanent" upon stakeholder approval.**		
WECC		the latest redline includes the deletion of the last paragraph in section 4.11. It appears that the last paragraph in section 4.11should be retained.
Response: Section 4.11 was changed and limited to Voting Positions, and as such this paragraph deletion was intentional. The parts intended to remain were moved to Section 4.10. No change made.		
PPL Corporation NERC Registered Affiliates		The PPL Companies believe that there should be a limit on the number of Additional Ballots that are required/can be performed, so that the Industry has an opportunity to appropriately affect the outcome of a Standards project through a reballot. Alternatively, there could be a procedural mechanism that would allow the industry to 'finalize' its rejection of a Standard or the need for a Standard. Section 1.4 - Under

Organization	Yes or No	Question 7 Comment
		Balance bullet it indicates "[t]he Registered Ballot Body serves as the consensus body voting to approve each new or proposed Reliability Standard, definition, Variance, and Interpretation." Suggest this be changed to "approve or reject". Also suggest adding a statement that they approve or reject retirement of a Reliability Standard, definition, Variance, and Interpretation. The PPL Companies support the changes the drafting team is making and believes that the changes will help the Standards drafting process. The drafting team has made excellent progress in refining the drafting process based upon the SPIG recommendations. In fact, the PPL Companies are committed to voting Affirmative to proposed changes that include the suggestions we have made in these comments.
Response: Thank you for your support. **Regarding the comment to limit the number of ballots, an intentional decision was made not to put an arbitrary limitation in place. While it might be clear in some cases after one or two ballots whether a standard is going to be successful, in other cases it may take much longer for consensus to arise. We believe this issue is better handled by the authority the SC has to terminate a project if it does not believe consensus can be achieved. An arbitrary limit could require a project to be restarted just as consensus is about to be reached.** **The Standards Committee is currently exploring whether there should be additional process(es), further guidelines and/or criteria for various Standards Committee decision points within the SPM such as acceptance rejection of a SAR or other drafting team output, when and how to terminate a standards development project, etc. This may be addressed a process documents or guidelines that support, but are not part of the SPM, or may be addressed in future revisions to the SPM. This matter is not ripe for inclusion in the current revision of the SPM; however, your comment is noted and will be considered during the ongoing work of the Standards Committee.**		
SERC Planning Standards Subcommittee		The present SPM has an "expedited standards development process" that was stricken. However, the ROP section 300 (Reliability Standards Development) requires that process. The SPM should retain that; without it in the SPM, NERC cannot respond to a request from a governmental authority for expedited development of a standard. The SPM therefore needs to retain that procedure, unless the SPM procedure is waived. If this provision were reinstated, the use of a waiver process

Organization	Yes or No	Question 7 Comment
		would be minimized since the expedited process would be a provision of the SPM.The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: Thank you for your comments. As you note, Section 16.0 is very similar to the currently –effective Standard Processes Manual section of the Expedited Reliability Standard Development Process. However, a Standard developed using the Expedited Reliability Standard Development Process is approved only on a conditional basis and it must *again* go through the standard development process in order to be made permanent. The Expedited Reliability Standard Development Process provides: **If a new or modified Reliability Standard is developed, approved by its ballot pool, and subsequently adopted by the NERC Board of Trustees through this expedited process, one of the following three actions shall occur [fn27]:** **• If the Reliability Standard is to be made permanent without additional substantive changes, then a SAR and a proposed Reliability Standard shall be submitted to the Reliability Standards staff immediately after the ballot. The project shall be added to the list of approved projects and shall proceed through the regular standard development process, including balloting by stakeholders, without any intentional delay.** **• If the Reliability Standard is to be substantively revised or replaced by a new Reliability Standard, then a project for the new or revised Reliability Standard shall be added to the list of projects to be added to the Reliability Standard Development Plan. The project shall be initiated as soon as practical after the ballot and the project shall proceed through the regular Reliability Standard development process, including balloting by stakeholders, as soon as practical but within two years of the date the Reliability Standard was approved by stakeholders using the expedited process.** **• The Reliability Standard shall be withdrawn through a ballot of the stakeholders within two years of the date the Reliability Standard was approved by stakeholders using the expedited process.** **This is clearly redundant and a waste of resources for NERC, the industry and the drafting team. Rather than repeating the standard development process, Section 16.0 would allow a Reliability Standard to become "permanent" upon stakeholder approval.**		
Georgia System Operations Corporation		The Quality Review processes are not well defined.There is still confusion with respect to the VRFs and VSLs in the document and if they are or are not applicable.There is still confusion on how the RSAWs are a component of the SPDM

Organization	Yes or No	Question 7 Comment
		and whether or not due process is applicable to the RSAWs.The Waivers portion of the SPDM does not seem to be open, transparent nor provide an opportunity for public comment nor due process in developing a Reliability Standard.The SPDM does not give a clear explanation of when and how registered entities comments are consistently addressed when submitted.The timing aspects of Additional Balloting are unclear.The Interpretations language of the SPDM has undergone significant changes and industry participation is not clearly defined and seems to be limited affecting due process.Eliminating Measures is not good unless they can be moved to the RSAWs and then the industry has the right to approve the Measures.The unofficial comment form does not adequately represent the language in the SPDM. It is paraphrased in certain cases and does not adequately represent the language in the SPDM.Some of the concepts in the proposed SPDM are good but NERC needs to have a workshop on this exercise and produce a quality document for such an important component of the ERO responsibilities.

Response: Thank you for your comments.

1) Based on the majority of the comments received to the previous posting, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM.

The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.

2) The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The new process

Organization	Yes or No	Question 7 Comment
		will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan, and the RSAW. **While the SCPS recognizes that the measures provide a level of certainty in regards to compliance obligations we do not agree that the industry is required to have the decision making authority on content of the measures. The measures are not enforceable and are therefore are not required to reside within the Reliability Standard. The Commission has acknowledged that it is in NERC's discretion whether to provide Measures for the Requirements of a Reliability Standard. See e.g., Mandatory Reliability Standards for the Bulk-Power System, 118 FERC 61,218 at P 253 (2007)(*"The Commission disagrees with commenters that a Reliability Standard cannot reasonably be enforced, or is otherwise not just and reasonable, solely because it does not include Measures and Levels of Non-Compliance. The Commission adopts the position it took in the NOPR that, while Measures and Levels of Non-Compliance provide useful guidance to the industry, compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement given the specific facts and circumstances of its use, ownership or operation of the Bulk-Power System. As we explained in the NOPR, and reiterate here: 'The most critical element of a Reliability Standard is the Requirements."*)** **3) In order to address your concern regarding notice to stakeholders for use of the Section 16.0 waiver, the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee has been incorporated.** **4) The changes to the Interpretations process have been implemented in order to clarify the basis and process for rejecting an interpretation, consistent with guidance issued by the NERC Board of Trustees in November 2009. Interpretations are balloted in the same manner as Reliability Standards, and through this mechanism registered entities are very much a part of the interpretation process.** **5) To the extent the changes are paraphrased in the comment form, the exact changes to the SPM are posted and available to all commenters. The Standards Committee's Communications and Planning Subcommittee will likely hold workshops and distribute information regarding implementation of changes to the SMP after the final version is approved.**
Tri-State G & T		There is inconsistency on who the drafting team works with to develop the RSAW. Section 3.6 states that the drafting team "(w)orks collaboratively with NERC Compliance Staff to develop Reliability Standard Audit Worksheets ("RSAWs") at the same time Reliability Standards are developed." But section 3.10 states that "Compliance Monitoring and Enforcement Staff are responsible for the development

Organization	Yes or No	Question 7 Comment
		of RSAWs." While this may indicate the same NERC staff, we believe that the language should be consistent.If voting "Negative without comment" is not possible (Section 4.11), then that exclusion from calculation of the consensus should be removed.
Response: The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan, and the RSAW. **The SPM will be revised to eliminate the inconsistencies associated with NERC Compliance staff involvement with the development of RSAWs.** **Participation in the NERC Ballot Pools comes with responsibility to participate and be helpful to the process. The value of any comment during the process cannot be underestimated and it is imperative to the NERC Standard Drafting Teams that they know why the entities voted negatively. The drafting teams needs this information and the industry needs to be encouraged to provide constructive comments in order to move the standards forward in an efficient manner.**		
Duke Energy		There needs to be clarity on what is actually being balloted and adopted by the Board of Trustees. Section 2.5 Elements of a Reliability Standard or section 4.9 Conduct Ballot and Non-binding Poll of VRFs and VSLs would seem to be logical places for this clarity. Are the Compliance Elements subject to ballot and adoption? Would they need to be balloted and adopted again if changed? As stated previously, Measures should be retained and should be balloted and adopted.
Response: While the SCPS recognizes that the measures provide a level of certainty in regards to compliance obligations we do not agree that the industry is required to have the decision making authority on content of the measures. The measures are not enforceable and are therefore are not required to reside within the Reliability Standard. The Commission has acknowledged that it is in NERC's discretion whether to provide Measures for the Requirements of a Reliability Standard. See e.g., Mandatory Reliability Standards for the Bulk-Power System, 118 FERC 61,218 at P 253 (2007)("*The Commission disagrees with commenters that a*		

Organization	Yes or No	Question 7 Comment
Reliability Standard cannot reasonably be enforced, or is otherwise not just and reasonable, solely because it does not include Measures and Levels of Non-Compliance. The Commission adopts the position it took in the NOPR that, while Measures and Levels of Non-Compliance provide useful guidance to the industry, compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement given the specific facts and circumstances of its use, ownership or operation of the Bulk-Power System. As we explained in the NOPR, and reiterate here: 'The most critical element of a Reliability Standard is the Requirements." **)**		
Independent Electricity System Operator		Typo: In section 5.2 in the redline SPM version, somewhere in the middle of the first sentence should read "... and a quality review..."
Response: There does not appear to be a typo, as multiple quality reviews may occur.		
Ameren		We are ok with having a legal review up front to develop a clear and unambiguous standard. However, we are not sure if the proposal implies one lawyer for each SDT as a member of the team or is this referring to one or two lawyers to be available to all the SDTs working in parallel and provide a review when the draft standard is approaching the final quality review of a standard.
Response: The proposed revision to Section 3.6 states that each drafting team "may" consist of a group of technical, legal, and compliance experts that work cooperatively with the support of the NERC Reliability Staff". There is no requirement for a specific number of attorneys. This language gives the Standards Committee flexibility to staff each standards development team with a mix of members that is appropriate to the particular project, including lawyers. The language indicates that the team will work cooperatively; this would include any lawyers who were appointed as members of the team. The Standard Committee's Standards Process Subcommittee is developing a guidance document for quality review that may better define the quality review process that will occur in parallel with the standards development process.		
MRO NSRF		None
SPP Standards Review Group		No additional comments.

END OF REPORT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Revisions to NERC Standard Processes Manual to Implement SPIG Recommendations

The Standards Committee Process Subcommittee thanks all commenters who submitted comments on the proposed revisions to the NERC Standard Processes Manual (SPM). The revisions to the SPM were posted for a 30-day public comment period from June 20, 2012 through July 19, 2012. Stakeholders were asked to provide feedback on the revisions to the NERC Standard Processes Manual to implement SPIG recommendations through a special electronic comment form. There were 48 sets of comments, including comments from approximately 128 different people from approximately 100 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Standards_Processes_Manual_revisions_SPIG_2012.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

1. In Recommendation 1, the SPIG recommended that NERC continue to meet the minimum requirements of the American National Standards Institute (ANSI) process to preserve ANSI accreditation. In Recommendation 5, the SPIG encouraged NERC to address standards process and resource issues by revising the standard development process to improve timely stakeholder consensus in support of new or revised reliability standards. This recommendation included suggestions that comment responses be bundled, and that the SDT post the draft standard for an informal comment period of 30 days but not be required to respond to comments. 10
2. As noted in Question 1, SPIG Recommendation 1 states that NERC should continue to meet the minimum requirements of the American National Standards Institute (ANSI) process to preserve ANSI accreditation. Currently, the NERC standards development process exceeds the minimum ANSI requirements in two areas that involve the treatment of Negative (No) ballots (ballots "rejecting" a standard or standards-related item, both with and without comments): 41
3. As part of Recommendation 4, the SPIG encouraged NERC to require the alignment of standard requirements/measures with Reliability Standard Audit Worksheets (RSAWs). The SPIG also recommended that NERC revise the Essential Elements of the Standards Template to eliminate redundancies. 78
4. As stated in Question 3, as part of Recommendation 4, the SPIG encouraged NERC to revise the Essential Elements of the Standards Template to eliminate redundancies, using Violation Severity Levels (VSLs) as an example. 99
5. As part of Recommendation 4, the SPIG encouraged NERC to ensure the cost effectiveness of standards through documentation of alternatives analysis. 139
6. If you have any other comments on these proposed revisions that you haven't already mentioned above, please provide them here: 162

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Mike Garton	Dominion	X	X			X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2.	Randi Heise	Dominion Resources Services, Inc.	MRO	5, 6
3.	Connie Lowe	Dominion Resources Services, Inc.	NPCC	5, 6
4.	Michael Crowley	Dominion Virginia Power	SERC	1, 2, 5, 6

2.	Group	Stephen Berger	PPL Corporation NERC Registered Affiliated	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Annette. M Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
2.			WECC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
3.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC 1										
4.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO 6										
5.			NPCC 6										
6.			SERC 6										
7.			SPP 6										
8.			RFC 6										
9.			WECC 6										
10.	Brent Ingebrigson	LG&E and KU Services Company	SERC 3										
3.	Group	Nick Wehner	ACES Power Marketing Standards Collaborators	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Manning	North Carolina Electric Membership Corporation	RFC	1, 3, 4, 5
2.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
3.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
4.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	SERC	1
5.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
6.	John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
7.	Susan Sosbe	Wabash Valley Power Association	RFC	3

4.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	Michael Schiavone	National Grid	NPCC	1
19.	Brian Robinson	Utility Services	NPCC	8
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

5.	Group	Terry Bilke	IRC-SCR		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Al DiCaprio	PJM	RFC	
2.	Kathleen Goodman	ISONE	NPCC	
3.	Don Weaver	NBSO	NPCC	
4.	Steve Meyers	ERCOT	ERCOT	
5.	Greg Campoli	NYISO	NPCC	
6.	Ben Li	IESO	NPCC	
7.	Charles Yeung	SPP	SPP	

6.	Group	Sasa Maljukan	Hydro One	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Kiguel	Hydro One Networks Inc.	NPCC	1

7.	Group	John Bussman	AECI and the G&T members Central Electric Power Cooperative, KAMO Power Cooperative, M&A Electric Power Cooperative, Northeast Electric Power Cooperative, NW Electric Power Cooperative, and ShoMe Power Electric	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			Cooperative										
No additional members listed.													
8.	Group	Steve Rueckert	Western Electricity Coordinating Council										X
No additional members listed.													
9.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM WEBB	WPS	MRO	3, 4, 5, 6
4.	JODI DENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL	MRO	1, 3, 4, 5
7.	DAVE RUDPOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	5, 6, 1, 3
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	DAN INMAN	MPC	MRO	1, 3, 5, 6

10.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Jonathan Hayes	Southwest Power Pool	SPP	2
3.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
4.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
5.	Julie Lux	Westar Energy	SPP	1, 3, 5, 6
6.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
7. Terri Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5									
11. Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Lorissa	Jones	WECC	1
2.	Hardev	Juj	WECC	1
3.	Fran	Halpin	WECC	5
4.	Denise	Koehn	WECC	1
5.	Erika	Doot	WECC	3, 5, 6
6.	Chris	Higgins	WECC	1

12. Group	Michael Jones	National Grid and Niagara Mohawk (A National Grid Company)	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Schiavone	Niagara Mohawk (A National Grid Company)	NPCC	3

13. Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

14. Group	Charles W. Long	SERC Planning Standards Subcommittee	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	Philip Kleckley	SC Electric & Gas Company	SERC	1
3.	Bob Jones	Southern Company Service	SERC	1
4.	Darrin Church	TVA	SERC	1

15. Group	David Dworzak	Edison Electric Institute	X		X	X	X					
Members can be accessed here: http://www.eei.org												

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	Jana Van Ness, Director Regulatory Compliance	Arizona Public Service Company	X		X		X	X				
17.	Individual	John A. Anderson and Michelle D'Antuono	Occidental Energy Ventures Corp. (OEVC) and Electricity Consumers Resource Council (ELCON) together called Industrial Consumers					X		X			
18.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
19.	Individual	Barry Lawson	National Rural Electric Cooperative Association (NRECA)			X	X						
20.	Individual	Daniel Duff	Liberty Electric Power					X					
21.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
22.	Individual	Peter Yost	Con Edison	X		X		X	X				
23.	Individual	Michael Gammon	Kansas City Power & Light	X		X		X	X				
24.	Individual	Don Jones	Texas Reliability Entity										X
25.	Individual	Terri Pyle	Oklahoma Gas & Electric	X		X		X					
26.	Individual	Thad Ness	American Electric Power	X		X		X	X				
27.	Individual	Michael Falvo	Independent Electricity System Operator		X								
28.	Individual	David Thorne	Pepco Holdings Inc.	X		X							
29.	Individual	Brian J Murphy	NextEra Energy Inc	X		X		X	X				
30.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
31.	Individual	NERC Staff Compliance Operations and Enforcement	NERC										
32.	Individual	Scott McGough	Georgia System Operations			X	X						
33.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
34.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
35.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
36.	Individual	Laura Lee	Duke Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
37.	Individual	Scott Miller	MEAG Power	X		X		X					
38.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
39.	Individual	Larry Raczkowski	FirstEnergy Corp	X		X	X	X	X				
40.	Individual	Kirit Shah	Ameren	X		X		X	X				
41.	Individual	Anthony Jablonski	ReliabilityFirst										X
42.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
43.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
44.	Individual	Kathleen Goodman	ISO New England Inc.		X								
45.	Individual	Steven Powell	Trans Bay Cable LLC	X									
46.	Individual	Patrick Brown	Essential Power, LLC					X					
47.	Individual	Maggy Powell	Exelon Corporation	X		X		X	X				
48.	Individual	Keira Kazmerski	Xcel Energy	X		X		X	X				

1. **In Recommendation 1, the SPIG recommended that NERC continue to meet the minimum requirements of the American National Standards Institute (ANSI) process to preserve ANSI accreditation. In Recommendation 5, the SPIG encouraged NERC to address standards process and resource issues by revising the standard development process to improve timely stakeholder consensus in support of new or revised reliability standards. This recommendation included suggestions that comment responses be bundled, and that the SDT post the draft standard for an informal comment period of 30 days but not be required to respond to comments.**

   NERC has confirmed with ANSI that only one formal comment period is required under ANSI's process. To fulfill Recommendation 5 while remaining in accordance with Recommendation 1, the revised standard process requires only one formal comment period. The drafting team is required to respond to comments in writing prior to a Final Ballot being conducted, although the team may respond in summary form. The drafting team may offer individual responses if deemed necessary or useful for developing additional consensus. Informal comment periods and other means of gathering informal input may be employed at any time to collect stakeholder feedback, but the drafting team is not required to respond in writing to comments obtained in these forums (though they may do so if they wish).

   Do these proposed revisions adequately address the SPIG Recommendations? If not, please explain why and offer an alternative solution for improving the timely development of standards while maintaining ANSI accreditation.

Summary Consideration:

By far, the dominant concern expressed in comments to Question 1 related to the commenting process, with particular concern to the treatment of comments and information gathered through the allowed multiple informal methods to collect stakeholder feedback on preliminary drafts and ideas early in the drafting process. The SPM drafting team responded to clarify that Section 4.5 (informal feedback) provides that all written comments received (whether for formal or informal postings) will be posted and that, while drafting teams are not required to provide a written response to each individual comment received, drafting teams are encouraged, where possible, to post a summary response that identifies how it used comments submitted by stakeholders. Also, the SPM drafting team points out that a draft standard will be improved incrementally as informal input is gathered and it is expected that the draft that will be posted for the formal posting and commenting/ballot will be a more robust draft that will reflect the input that has been obtained from the industry through the multiple informal forums.

Sections 4.12 and 4.13 have been revised to clarify the requirements to consider and respond to all written comments. The proposed new Sections 4.12 and 4.13 are as follows:

4.12 Consideration of Comments

If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot.

There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot.

4.13 Additional Ballots

A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted.

However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted.

Also, some of the comments under Question 1 reflected concern about the new waiver section 16.0, which is addressed by responses to comments received under question 6.

Other less frequent comments address the following concerns: (1) uncertainty of the CEAP as it relates to uncertainty of the role of the RISC and its relation to the SC; (2) concern that the revisions may shorten the time allowed for developing consensus but not necessarily foster consensus; (3) treatment of “no” votes, (4) automation of comment processing, and (5) rigorous project management. These topics are primarily addressed within the responses to other questions within this report.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	Due to the uncertainty of the CEAP and not knowing the responsibilities of the RISC at the time of this posting, it is premature to agree that the

Organization	Yes or No	Question 1 Comment
		revisions adequately address the SPIG recommendations.
Response: Thank you for your comments. Please see the responses to comments for the CEAP, which was posted for a separate comment period which ended on July 6, 2012, for your concerns about the content of the CEAP. Also, the Charter for the Reliability Issues Steering Committee, (RISC), is not under the purview of the Standards Committee and is not part of the standard development process. The draft charter and initial slate for the RISC was approved by the NERC BOT in August and the SC looks forward to clarifying the relationship between the SC and RISC. The Standards Committee (SC) acknowledges that there will be a necessary interface coordination to be implemented in order to assure effective coordination between the activities of the RISC and those of the SC.		
IRC-SRC	No	While we agree improvements can be made to the commenting process, some safeguards are needed. For informal commenting periods, the drafting team should be obliged to post a summary of the comments received and the changes made based on the posting. For formal commenting, drafting teams need to provide a response to each unique comment during a formal comment period. Comments received during the formal commenting period need to be posted. It's not clear why this language was stricken.
Response: Thank you for your comments. Section 4.5 of the proposed SPM revisions provides that information gathered from informal comment periods will be posted. Additionally, information gathered during the informal comment periods will be reflected in the posted draft at the time of the formal posting. Additionally, per Section 4.5, the drafting teams are encouraged, where possible, to post a summary response, following each informal stakeholder feedback session, that identifies how it used comments submitted by stakeholders. To address concerns regarding comments received during formal commenting periods and other stakeholder's comments regarding bundling of comments and providing responses back, Sections 4.12 and 4.13 have been revised as follows: **4.12: Consideration of Comments** If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must		

Organization	Yes or No	Question 1 Comment
communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot. There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot. **4.13: Additional Ballots** A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted. However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted.		
Hydro One	No	Due to the uncertainty of the CEAP and not knowing the responsibilities of the RISC at the time of this posting, it is premature to agree that the revisions adequately address the SPIG recommendations. The RISC scope must be developed and communicated so that there is a clear differentiation with respect to the roles and responsibilities that the Standards Committee currently has.
Response: Thank you for your comments. Please refer to the responses to Question 5 of the SPM comment form which is specific to the CEAP. Additional information regarding the proposed CEAP process was included in a separate comment posting from May 7, 2012 through July 6, 2012. Additionally, the Charter for the Reliability Issues Steering Committee, (RISC), is not under the purview of the Standards Committee and is not part of the standard development process. The draft charter and initial slate for the RISC was approved by the NERC BOT in August and the SC looks forward to clarifying the relationship between the SC and RISC. The Standards Committee (SC) acknowledges that there will be a necessary interface coordination to be implemented in order to assure effective coordination between the activities of the RISC and those of the SC.		

Organization	Yes or No	Question 1 Comment
National Grid and Niagara Mohawk (A National Grid Company)	No	National Grid supports the goal of SPIG recommendation 5 to revise the standard development process to improve timely stakeholder consensus. However, the steps taken to streamline the average duration of the standard development process must be balanced with the need to allow adequate time and opportunity for stakeholder review and input. National Grid agrees that requiring only one formal comment period is an adequate way to gain process efficiency; however, this reduction in formal comment periods should be balanced with a requirement for at least one method for informal stakeholder feedback prior to the formal comment period. Because informal feedback is optional in the current draft SPM, the proposed revisions to Sections 4.5 and 4.7 permit a standard to be developed with only one formal comment period and no other opportunity for the industry to provide feedback and guidance. National Grid is concerned that this process may inadvertently result in more process delays. With the possibility of only one chance to submit feedback, the formal comments will might be overloaded and burdensome to process with information that could have been gathered informally and the need for more successive ballots may result in order to address issues raised in formal comments. National Grid understands that informal feedback is encouraged, but without a requirement, the need and pressure for faster and faster processing of standard development could easily result in a trend of abandonment of informal feedback with the result of a unintended longer process on the back end of a project. Making informal feedback a required step will guard against possibly unnecessary delay while achieving process efficiency in conjunction with the elimination of the second formal comment period. In place of the eliminated additional formal comment period, the drafting team should be required, not encouraged, to use at least one of the methods for informal stakeholder feedback that is set forth in Section 4.5. By retaining the flexibility to use a variety of informal feedback methods,

Organization	Yes or No	Question 1 Comment
		and by retaining the flexibility for the drafting team to set the deadline for informal comment periods (i.e. not requiring 30-days for informal feedback), sufficient time-savings can be achieved in the overall process, but the industry will be guaranteed at least two opportunities to weigh in. This is the most effective and fair way to meet SPIG recommendation 5. Accordingly, National Grid recommends the following edit to the first sentence of proposed draft of Section 4.5 (changes appear in italicized text): Prior to the formal comment period, drafting teams must use at least one of the following methods to collect informal stakeholder feedback on preliminary drafts of its documents: o Informal comment period(s) of duration at the discretion of the drafting team o Webinar(s) o Industry meeting(s) o Workshop(s) o Other mechanism(s) that solicit informal industry feedback in an open and transparent way. [The remainder of the draft text of Section 4.5 could remain as drafted]. With regard to permitting responses to formal comments in summary form, National Grid supports this change as a reasonable method to achieve process efficiency because the language of the draft Section 4.13 makes clear that "the drafting team must respond in writing to every stakeholder comment" and "all comments and objections must be responded to by the drafting team." As long as this language remains, National Grid supports responses in summary form. National Grid notes that drafting teams should strive to ensure that summary responses clearly correspond to comments to which they respond.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. The proposed changes to the informal comment period as discussed in Section 4.5 of the draft SPM continue to adhere to the ANSI accreditation requirements. Removal of the 30-day informal comment period allows the drafting team to use multiple informal information gathering forums, which does not preclude an informal comment period as determined by the drafting team, is intended to result in a draft that is more reflective of an industry consensus considering all stakeholder input. This process change would be coupled with a more rigorous project management of the drafting process, resulting in more timely completion of the standard. The decision to eliminate a required informal comment period was based on NERC streamlining the standard development process while still maintaining stakeholder input throughout the process. The SPM drafting team determined that providing the various informal gathering forums was a benefit to the industry but because each standard development project is unique, wants to preserve flexibility both in how informal feedback is solicited as well as whether a particular project calls for it. The SPM drafting team recognizes this is a change. Bundling like comments is included as a recommendation in the SPIG report to assist in streamlining the process for response of all comments by the SDT.		
Florida Municipal Power Agency	No	The reason we checked the "no" box is that FMPA believes that some level of response to comments before ballots in addition to the Final Ballot is necessary to meet the SPIG Recommendation 5 "to improve timely, stakeholder consensus" and believes the SPM ought to require the SDTs to develop summary responses to comments, bundling comments of a similar nature, for ballots prior to the Final Ballot. By not responding in summary form to bundled comments, FMPA believes that the number of ballots (which is a driver to delays in the current process) will not be reduced because entities will be left to guess at how their concerns were addressed (or not addressed) from previously submitted comments; which will likely result in negative voting. FMPA believes that the SDT ought to be required to develop summary responses to bundles of the most important comments (e.g., something less than every comment, but, comments determined to be more important in some way, such as volume of similar comments received) received in ballots other than the final ballot (Section 4.13 might be a good place for this).In addition, through deletion of a large portion of section 4.9, publicly posting of comments received from stakeholders seems to have been eliminated. FMPA believes publicly posting these comments received

Organization	Yes or No	Question 1 Comment
		important to achieving timely consensus and suggests adding words to that effect in Sections 4.7 and 4.9

Response: Thank you for your comments. Section 4.5 of the proposed SPM revisions provides that information gathered from informal comment periods will be posted.

Based on the stakeholder comments regarding bundling of comments and providing responses back, the SPM drafting team is proposing the following new Sections 4.12 and 4.13 to replace the previous Sections 4.12 and 4.13 of the draft SPM:

4.12: Consideration of Comments

If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot.

There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot.

4.13: Additional Ballots

A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted.

However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted.

National Rural Electric Cooperative Association (NRECA)	No	Any changes made to the commenting (and balloting which will be discussed in Q2) process must be done carefully so as not to limit, or appear to limit, the ability of industry stakeholders to effectively participate in the standard

Organization	Yes or No	Question 1 Comment
		development process. This will also need to be done with caution in order to prevent and limit the number of appeals that may be submitted due to stakeholders believing their comments were not properly addressed. NRECA understands the desire to modify the Standards Process Manual (SPM) in such ways that will help to shorten the time it takes to develop a standard, definition or interpretation, etc. However, we do have concerns about some of the changes that have been proposed. The use of summary comments instead of individual responses to each stakeholder comment is a significant formal change to the SPM. While this is permitted in the current SPM for informal ballots, permitting summary comments as the only comment response required in the one and only formal comment period is new and could be problematic. First, a stakeholder may not receive a response from a SDT until the final formal comment period even after possibly submitting multiple rounds of comments. Second, a stakeholder may not have any indication how their comments were treated or responded to by the SDT since no comment responses are required until the final comment period. Third, the response they may receive may not be a direct response to their comment as it could be generically responded to in a summary comment. NRECA believes summary comments are adequate for the informal comment periods, but that individual responses to comments should be required in the final formal comment period.

Response: Thank you for your comments. Section 4.5 of the proposed SPM revisions provides that information gathered from informal comment periods will be posted.

The purpose of allowing SDT teams to solicit informal feedback (Section 4.5) through multiple forums is to allow for flexibility in the standard development process that enables the SDT to develop a more robust draft from one step to the next with a near final draft when a formal posting is made. As a result, the consensus developed using the information gathered during the informal feedback forums will be posted at the time of the formal posting.

The proposed changes to the informal comment period as discussed in Section 4.5 of the draft SPM will continue to adhere to the ANSI accreditation requirements. Removal of the 30-day informal comment period allows the drafting team to use multiple

Organization	Yes or No	Question 1 Comment

informal information gathering forums, which does not preclude an informal comment period as determined by the drafting team, and is intended to result in an industry consensus draft that is more reflective of all stakeholder input. This process change would be coupled with more rigorous project management of the drafting team, resulting in more timely completion of the process.

The decision to eliminate a required informal comment period was based on NERC streamlining the standard development process while still maintaining stakeholder input throughout the process. The SPM drafting team determined that providing the various informal gathering forums was a benefit to the industry but because each standard development project is unique, wants to preserve flexibility both in how informal feedback is solicited as well as whether a particular project calls for it.

Additionally, based on the stakeholder comments regarding bundling of comments and providing responses back, the SPM drafting team is proposing the following new Sections 4.12 and 4.13 to replace the previous Sections 4.12 and 4.13 of the draft SPM:

4.12: Consideration of Comments

If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot.

There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot.

4.13: Additional Ballots

A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted.

However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that

Organization	Yes or No	Question 1 Comment
significant changes are needed and an Additional Ballot will be conducted. Every comment will be responded to by the drafting team. The drafting team has the ability to bundle responses if the comments from different stakeholders address the same issues. This process is included in the proposed new version of Section 4.12 of the SPM.		
Manitoba Hydro	No	It is not clear that the proposal will "improve timely stakeholder consensus" as per Recommendation 5. The proposal will shorten the time period during which consensus must be reached, but not necessarily foster consensus.
Response: Thank you for your comments. The proposed changes will continue to adhere to the ANSI accreditation requirements. Allowing the drafting team to use multiple informal information gathering forums is intended to result in a draft that is more reflective of industry consensus with all stakeholder input. This process change would be coupled with more rigorous project management of the drafting team, resulting in more timely completion of the process.		
Pepco Holdings Inc.	No	Not in agreement with to eliminate providing summary responses to comments for each formal comment period. For the stakeholders to understand the direction and thought process of the SDT, the feedback is needed after each formal comment period.
Response: Thank you for your comments. Based on the stakeholder comments regarding bundling of comments and providing responses back, the SPM drafting team is proposing the following new Sections 4.12 and 4.13 to replace the previous Sections 4.12 and 4.13 of the draft SPM: **4.12: Consideration of Comments** If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team		

Organization	Yes or No	Question 1 Comment
		has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot. There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot. **4.13: Additional Ballots** A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted. However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted. Section 4.5 of the proposed SPM revisions provides that information gathered from informal comment periods will be posted. The SPM drafting team recognizes this is a change. Bundling like comments is included as a recommendation included in the SPIG report to assist in streamlining the process for responding to all comments by the SDT.
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency (IMEA) supports comments submitted by Florida Municipal Power Agency.
Response: Thank you for your comments. Based on the stakeholder comments regarding bundling of comments and providing responses back, the SPM drafting team is proposing the following new Sections 4.12 and 4.13 to replace the previous Sections 4.12 and 4.13 of the draft SPM: **4.12: Consideration of Comments** If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team		

Organization	Yes or No	Question 1 Comment
		has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot. There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot. **4.13: Additional Ballots** A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted. However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted. Section 4.5 of the proposed SPM revisions provides that information gathered from informal comment periods will be posted.
Ameren	No	(1) We believe that accelerating the schedule for draft standards review at NERC's end of the process will not help stakeholder to keep up with necessary review and commenting on draft standards. While we applaud the decision to maintain the ANSI accreditation, it can be viewed that it defines a minimal set of requirements. rather than more steps in the process which may be necessary for development of the NERC Standards. Developing a quality standards in many cases just takes time and effort that may not be subject to streamlining.(2) There seems to be a conflict between the revisions in the SPM and the recommendation report from SPIG for the informal 30-day comment period. The SPIG states (Page 14, Proposed Details 2nd Bullet, ii) to post draft standard for informal 30-day comment period but the SDT does not have to respond; however, the SPM states (Page 19 section 4.5: Rationale) that drafting teams are not required to have a 30-day informal comment period. In addition to the one formal comment period, which presumably comes at the end of the standards development process just prior to balloting we request that the SDT have additional

Organization	Yes or No	Question 1 Comment
		informal comment periods earlier in the process as currently is done. (3) We have the following concerns/comments about the proposed "summary" response:a. We currently search SDT responses to comments by individual name and/or company name. If a summary reply is made, how then will we be able to find the responses to our specific comments within the "summary" response?b. What criteria the SDT will use to choose which comments not to respond to? We believe that the criteria for this activity need to be provided upfront. Also, what would happen to the submitted comments which the SDT determines not to respond to? Would those comments be published?

Response:

Thank you for your comments. Section 4.5 of the proposed SPM revisions provides that information gathered from informal comment periods will be posted.

The purpose of allowing SDT teams to solicit informal feedback (Section 4.5) through multiple forums is to allow for flexibility in the standard development process that enables the SDT to develop a more robust draft from one step to the next with a near final draft when a formal posting is made. As a result, the consensus developed using the information gathered during the informal feedback forums will be reflected in the posted draft at the formal posting.

The proposed changes to the informal comment period as discussed in Section 4.5 of the draft SPM continue to adhere to the ANSI accreditation. Removal of the 30-day informal comment period allows the drafting team to use multiple informal information gathering forums, which does not preclude an informal comment period as determined by the drafting team, and is intended to result in an industry consensus draft that is more reflective of all stakeholder input. This process change would be coupled with more rigorous project management of the drafting team, resulting in more timely completion of the process.

The decision to eliminate a required informal comment period was based on NERC streamlining the standard development process while still maintaining stakeholder input throughout the process. The SPM drafting team determined that providing the various informal gathering forums was a benefit to the industry but because each standard development project is unique, wants to preserve flexibility both in how informal feedback is solicited as well as whether a particular project calls for it.

The changes in the entire standard development process were developed to provide a number of improvements including the ability of the drafting team to have the flexibility to build consensus early in the process via various forums. The SPM changes have

Organization	Yes or No	Question 1 Comment
preserved the ability of the standard drafting team to use informal comment periods as needed. To further address your comments, as well as other stakeholder comments regarding summary or bundling of comments and providing responses back, the SPM drafting team is proposing the following new Sections 4.12 and 4.13 to replace the previous Sections 4.12 and 4.13 of the draft SPM: **4.12: Consideration of Comments** If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot. There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot. **4.13: Additional Ballots** A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted. However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted.		
Indiana Municipal Power Agency	No	Indiana Municipal Power Agency supports the comments submitted by Florida Municipal Power Agency.
Response:		

Organization	Yes or No	Question 1 Comment
Thank you for your comments. Please see the response to FMPA's comments.		
American Transmission Company	No	The SPM, as proposed, does not address all the SPIG Recommendation #5 items:Ballot process shall: o Provide options for voting "No" with guiding choices for the answer with a comment section on the ballotThis item was a major discussion point for SPIG and it is not addressed in the proposed SPM. We remind the group modifying the SPM, that the reason for the recommendation is to insure that every "no" vote would have a comment, which eliminates the need for determine if vote should be counted. Because the modification did not incorporate this recommendation completely the team has both rehashed the discussion that took place under SPIG and had to include unnecessary language about appealing "no" votes with comments. The SPIG solution must be incorporated into the SPM SPIG Recommendations modify the comment process as follows: o The SDT will post draft standard for informal comment period of 30-days, but not be required to respond to comments. o The SPIG did not recommend removal of the 30-Day comment period for informal comments, only that the SDT would not be required to respond to those comments. o Promote an automated system for managing comments.Although this modification does not belong specifically in the SPM, ATC believes that the response to this item needs to be addressed in the modifications. In addition to the above items there are a number of Recommendation 5 items that are not being addressed. The team needs to address these items in some manner as an indication that they are not being ignored. o Rigorous Project Management o SDT Model
Response: Thank you for your comments. The proposed changes to the informal comment period as discussed in Section 4.5 of the draft SPM continue to adhere to the ANSI accreditation requirements. Removal of the 30-day informal comment period allows the drafting team to use multiple informal information gathering forums, which does not preclude an informal comment period as determined		

Organization	Yes or No	Question 1 Comment
by the drafting team, and is intended to result in an industry consensus draft that is more reflective of all stakeholder input. This process change would be coupled with more rigorous project management of the drafting team, resulting in more timely completion of the process. The decision to eliminate a required informal comment period was based on NERC streamlining the standard development process while still maintaining stakeholder input throughout the process. The SPM drafting team determined that providing the various informal gathering forums was a benefit to the industry but because each standard development project is unique, wants to preserve flexibility both in how informal feedback is solicited as well as whether a particular project calls for it. The topic of 'no' votes is not included in the scope of Question #1. Please refer to Question #2 for response to comments on 'no' ballots. **Section 4.3 (Form Drafting Team)** of the proposed SPM changes includes a reference to project management expertise. The automated system, the use of rigorous project management and the SDT model do not require SPM changes in order to implement these changes. NERC staff is currently addressing these recommendations.		
ISO New England Inc.	No	While we agree improvements can be made to the commenting process, some safeguards are needed. For informal commenting periods, the drafting team should be obliged to post a summary of the comments received and the changes made based on the posting. For formal commenting, drafting teams need to provide a response to each unique comment during a formal comment period. Comments received during the formal commenting period need to be posted. It's not clear why this language was stricken.
Response: Thank you for your comments. To address your comments, as well as other stakeholder comments regarding posting and bundling of comments and providing responses back, the SPM drafting team is proposing the following new Sections 4.12 and 4.13 to replace the previous Sections 4.12 and 4.13 of the draft SPM: **4.12: Consideration of Comments** If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team		

Organization	Yes or No	Question 1 Comment
may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot. There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot. **4.13: Additional Ballots** A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted. However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted. Section 4.5 of the proposed SPM revisions provides that information gathered from informal comment periods will be posted.		
AECI and the G&T members Central Electric Power Cooperative, KAMO Power Cooperative, M&A Electric Power Cooperative, Northeast Electric Power Cooperative, NW Electric Power Cooperative, and ShoMe Power Electric Cooperative	Yes	However, the process should ensure that the last comment period before balloting will be a formal comment period, and each and every comment will be responded to. This could be in summary of many if similar or individually.
Response: Thank you for your comments and support. To address your comments, the following response which includes both informal and formal comment periods is provided.		

Organization	Yes or No	Question 1 Comment
Section 4.5 of the proposed SPM revisions provides that information gathered from informal comment periods will be posted. The purpose of allowing SDT teams to solicit informal feedback (Section 4.5) through multiple forums is to allow for flexibility in the standard development process that enables the SDT to develop a more robust draft from one step to the next with a near final draft when a formal posting is made. As a result, the consensus developed using the information gathered during the informal feedback forums will be reflected in the version posted at the formal posting. The SPM drafting team is proposing the following new Sections 4.12 and 4.13 to replace the previous Sections 4.12 and 4.13 of the draft SPM: **4.12: Consideration of Comments** If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot. There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot. **4.13: Additional Ballots** A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted. However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted.Section 4.7 of the draft SPM requires a 45-day formal comment period with a ballot period being included in this 45-day period. This requirement meets ANSI accreditation requirements.		

Organization	Yes or No	Question 1 Comment
Western Electricity Coordinating Council	Yes	WECC supports this revision provided that the drating teams are still required to review and consider all comments received. Section 4.5 of the proposed revisions to the SPM explains that drafting teams are not required to provide responses to feedback from informal comment periods and we support this. However, WECC suggests that clarification be added that indicates the drafting teams must consider the feedback. Without the requirement to consider the feedback, there is no reason for even seeking the feedback.

Response:

Thank you for your comments and support. All comments and feedback received by the drafting team are considered and a response is provided. It is the collective decision of the team to determine what specific stakeholder input is then incorporated into the draft standard.

Section 4.5 of the proposed SPM revisions provides that information gathered from informal comment periods will be posted.

However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an additional ballot will be conducted.

Comments are responded to per the proposed new Sections 4.12 and 4.13 to replace the previous Sections 4.12 and 4.13 of the draft SPM:

> **4.12: Consideration of Comments**
>
> If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot.

Organization	Yes or No	Question 1 Comment
There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot. **4.13: Additional Ballots** A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted. However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted.		
MRO NSRF	Yes	The NSRF does not believe the proposed revisions to the SPM addressed the SPIG Recommendations as spelled out in the SPIG Report below: Modify the comment process to: o Have the SDT post draft standard for informal comment period of 30-days, but not be required to respond to comments. o Promote an automated system for managing comments. Ballot process shall: o Provide options for voting "No" with guiding choices for the answer with a comment section on the ballot.
Response: Thank you for your comments and support. The proposed changes to the informal comment period as discussed in Section 4.5 of the draft SPM continue to adhere to the ANSI accreditation. Removal of the 30-day informal comment period allows the drafting team to use multiple informal information gathering forums, which does not preclude an informal comment period as determined by the drafting team, and is intended to result in an industry consensus draft that is more reflective of all stakeholder input. This process change would be coupled with more rigorous project management of the drafting team, resulting in more timely completion of the process. The decision to eliminate a required informal comment period was based on NERC streamlining the standard development process while still maintaining stakeholder input throughout the process. The SPM drafting team determined that providing the various informal gathering forums was a benefit to the industry but because each standard development project is unique, wants to preserve flexibility both in how informal feedback is solicited as well as whether a particular project calls for it.		

Organization	Yes or No	Question 1 Comment
The topic of 'no' votes is not included in the scope of Question #1. Please refer to Question #2 for response to comments on 'no' ballots. **Section 4.3 (Form Drafting Team)** of the proposed SPM changes includes a reference to project management expertise. The automated system, the use of rigorous project management and the SDT model do not require SPM changes in order to implement these changes. NERC staff is currently addressing these recommendations.		
Dominion	Yes	Dominion notes that the SPIG recommendations are draft at this point, so any responses to this comment form may or may not remain valid once the SPIG recommendations are finalized. Additionally, it is difficult to determine whether Question #1 is referring to SPIG Recommendation 1 and 5 or all the SPIG recommendations. Dominion assumes, for the sake of providing comments, that Question #1 is addressing SPIG Recommendations 1 & 5.
Response: Thank you for your comments and support. While the posted SPIG recommendations are identified as draft, the BOT approved the recommendations at their May 9, 2012 meeting. Yes, a subteam was assigned the task of addressing SPIG Recommendation 1 and part of Recommendation 5 which pertain to maintaining ANSI accreditation requirements and to streamlining of commenting and balloting processes. Question #1 is intended to cover the proposed revisions to the SPM that address those parts of the Recommendations 1 and 5.		
Bonneville Power Administration	Yes	BPA supports one formal comment period, BPA sees significant value in the drafting team responding individually rather than in summary form, understanding that like comments or similar comments can be grouped together. BPA believes that these changes need to be clearly communicated to the industry.
Response: Thank you for your comments and support. In agreement with your comments, the summary responses to comments must address each comment, although the format of doing so may allow the bundling of similar comments so that one response can be given to address the issues raised. The summary must be robust enough to ensure that each individual comment is		

Organization	Yes or No	Question 1 Comment
addressed.		
SERC Planning Standards Subcommittee	Yes	However, the process should ensure that the last comment period before balloting will be a formal comment period, with individual written responses to each comment submitted.
Response: Thank you for your comments and support. Section 4.7 of the draft SPM requires a 45-day *formal* comment period with a ballot period being included in this 45-day period. The drafting team must address each comment, although the format of doing so may allow the bundling of similar comments so that one response can be given to address the issues raised. If the drafting team responds in summary form, the summary must be robust enough to ensure that each individual comment is addressed.		
Occidental Energy Ventures Corp. (OEVC) and Electricity Consumers Resource Council (ELCON) together called Industrial Consumers	Yes	Occidental Energy Ventures Corp. (OEVC) and the Electricity Consumers Resource Council (ELCON) (herein: Industrial Consumers), the Sector 8 representatives of large end-use electricity consumers on the MRC, believe it essential that NERC's Standards Development process continue to meet at least the minimum ANSI requirements.However, we have two concerns which we believe are an improper translation from the intention of the SPIG recommendations to the updated Standards Process Manual. First, a vehicle must exist for the industry to request additional formal comment periods during the development of complex and/or controversial modifications to Reliability Standards. Without this provision, it is possible that project teams will make major modifications between multiple successive 10 day ballot periods - in our view, a misuse of the intent. For example, we cannot imagine that the CIP Version 5 Standards could be effectively vetted in a single formal review.Second, the legal memorandum posted concurrently with the proposed modifications essentially allows NERC to bypass the ANSI process if they deem it necessary without any threat of loss of accreditation. Although we understand that regulatory standards have inherent differences from voluntary industry-developed Standards, it goes against the partnership principals that NERC and FERC expound. Actions have consequences and it is unseemly to portray a process as communal when it

Organization	Yes or No	Question 1 Comment
		is clearly not.
Response: Thank you for your comments and support. The entire construct of the commenting and balloting process within the standard development process is designed to provide the industry a vehicle to express its concerns and to determine, through ballot, when consensus is reached. If a stakeholder does not feel consensus has been reached, they can appeal any action or inaction at any step in the process pursuant to Section 8.0 of the Standard Processes Manual. The legal memorandum posted is simply a comparison of the NERC Standards Processes with ANSI requirements and was provided solely for informational purposes. Regardless of what is stated in the memorandum the changes to the SPM were drafted with the intent of complying with the SPIG recommendation of preserving ANSI accreditation of the standards development process. The proposed modifications do not allow for NERC to bypass the ANSI process or otherwise provide NERC any authority whatsoever. As noted in the introduction, the memorandum takes no position on whether any particular changes should be made, nor does it express an opinion as to the acceptability of any particular change to the broader stakeholder community.		
Salt River Project	Yes	SRP supports the modifications to the SPM as recommended by the SPIG
Response: Thank you for your comment and support.		
Liberty Electric Power	Yes	Agree with this provision, but the Process Manual should be revised to require comments be immediately posted publicly so all entities can be informed of the views of their peers. This is especially vital considering the intent to modify the criteria for counting negative votes.
Response: Thank you for your comments and support. NERC is considering software modifications that would allow immediate posting of comments as they are received, and this could be implemented without a process change.		
Kansas City Power & Light	Yes	It is important for the Standard Drafting Team (SDT) to understand major industry concerns with a proposed standard. The suggestions in recommendation 1 to improve the process are likely to improve the process. To further strengthen the process, suggest the comments process include a method for the industry to identify “deal breakers” in a proposed standard, explain why it is a “deal breaker”, and suggest a viable alternative. Where a

Organization	Yes or No	Question 1 Comment
		"deal breaker" represents if the proposed standard is not modified, the entity cannot support the standard. This will aid the SDT to focus on the matters of most importance, consider meaningful alternatives and come to an effective and swifter resolution.
Response: Thank you for your comments and support. The entire construct of the commenting and balloting process within the standard development process is designed to provide the industry a vehicle to express its concerns and to determine through ballot when consensus is reached. Identifying "deal breakers" can certainly be helpful to the SDT and commenters are encouraged to be as specific as possible in identifying their concerns and the resolution to those concerns. The SCPS believes this can be accomplished through the established commenting process and does not believe this level of detail should be required in the SPM.		
Texas Reliability Entity	Yes	We support these revisions. However, if a commenter makes a comment or objection in an early comment period, and fails to repeat it in the formal comment period, will the comment or objection be deemed to be waived or abandoned? In Part 4.7, relating to "Formal Comment Period," we suggest adding the following provision: "To ensure full and individual consideration of a comment or objection and to preserve an issue for appeal, an entity should submit its comment or objection in the final formal comment period, even if it previously made the comment in a prior comment period (formal or informal) and the concern was not resolved."
Response: Thank you for your comments and support. The entire construct of the commenting and balloting process within the standard development process is designed to provide the industry a vehicle to express its concerns and to determine through ballot when consensus is reached.		
Independent Electricity System Operator	Yes	As long as voting remains a strong lever for adoption/rejection of a standard, we find these proposed changes acceptable.
Response: Thank you for your comment and support. Yes, voting continues to be a principal part of the process.		

Organization	Yes or No	Question 1 Comment
NextEra Energy Inc	Yes	NextEra Energy, Inc. (NextEra) agrees with streamlining the balloting and comment periods, while maintaining ANSI accreditation.
Response: Thank you for your comment and support.		
Georgia System Operations	Yes	While we encourage efficient use of resources and have no objection to responses being written in summary form, we believe it is imperative that the SPM require that every issue raised in a comment be responded to. The permission to respond in summary form cannot be used as permission not to respond to a difficult issue simply because only a single commenter raised it.

Response: Thank you for your comments and support. To address your comments, as well as other stakeholder comments regarding posting and summary or bundling of comments and providing responses back, the SPM drafting team is proposing the following new Sections 4.12 and 4.13 to replace the previous Sections 4.12 and 4.13 of the draft SPM:

4.12: Consideration of Comments

If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot.

There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot.

4.13: Additional Ballots

A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to

Organization	Yes or No	Question 1 Comment
conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted. However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted.		
Duke Energy	Yes	The change to reply to comments in summary form adequately addresses the SPIG recommendation. Duke Energy does not support the SPIG recommendation to not require responses to the comments submitted in the informal 30-day comment period, as this will make it difficult for entities to determine how or if the Standard Drafting Team used the entity's comments. The response to comments is an important tool for developing industry consensus, and providing that response in summary format should enhance the efficiency of the SDT.
Response: Thank you for your comments and support. Allowing the drafting team to use multiple informal information gathering forums, which does not preclude an informal comment period as determined by the drafting team, is intended to result in an industry consensus draft that is more reflective of all stakeholder input.		
Exelon Corporation	Yes	Exelon supports the dual goal of maintaining ANSI accreditation and streamlining the development process. Informal comment periods are useful and should be effectively utilized to gather technical and practical input at the front end of the standard development. Figure 1 implies that informal comment periods will only be used for the SAR. Section 4.5 enables SDTs to conduct informal input gathering including informal comment periods. While the specified 30-day time period has been removed, Figure 1 will be more clear if it notes the option for informal input gathering.In streamlining the process, the Standards Committee must not lose focus on how the iterative process leads to a successful final standard. The iterative process refines the standard language addressing problematic aspects over

Organization	Yes or No	Question 1 Comment
		revisions. The requirements are dynamic - a change to resolve one problem is only successful if it does not create another problem. Shortening the process is only achieved with affirmative votes. Affirmative votes depend on standard language being technically accurate for all covered functional entities, clearly understood and realistically achievable. While responding to individual's comments presents a notable workload for drafting teams, the information learned in that process is essential. The individual response makes it clear to the commenter that the SDT heard their issue and it illustrates how the SDT understood the comment. Given the diversity of system designs within the electric delivery grid, summaries run the risk of losing or diluting the technical issues raised by the industry. If summary responses are the only form of response, they must work hard to clearly respond to all points raised by commenters and do so in time for voters to digest the responses. Furthermore, comments that focus on issues prompting a negative vote are critical to the SDT effort. Commenters seek to improve the standard language at all degrees and should be encouraged to do so whether in correcting typos or raising flawed technical assumptions. It may be worthwhile to include an option for SDTs to respond individually and/or some other means to more clearly identify the objections among stakeholders that motivate a negative vote.

Response: Thank you for your comments and support. Figure 1, Step 3 (Develop Draft of Standard and Implementation Plan), includes "Collect Informal Feedback," this language is intended to apply to the entire step in the process, i.e., the development of a draft standard and implementation plan. The Standards Committee understands the iterative nature of the process and the proposed SPM changes would allow drafting teams to use multiple informal methods to iteratively improve a standard prior to posting for the initial formal comment period. This is intended to ensure that the draft that is posted is technically accurate and well-supported.

Every comment will be responded to by the drafting team. The drafting team has the ability to bundle responses if the comments from different stakeholders address the same issues. This process is included in the proposed revision to Section 4.12 of the SPM below. Standard drafting teams also have the option to respond individually to objections pursuant to the new Section 4.12

Organization	Yes or No	Question 1 Comment
included below which is replacing the previous Section 4.12 of the draft SPM: **4.12: Consideration of Comments** If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot. There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot.		
PPL Corporation NERC Registered Affiliated		The PPL Companies appreciates the Standards Committee's efforts to revise and streamline the Standard Development process. PPL Companies are in agreement that the proposed recommendations do adequately address the SPIG recommendations, but have the following concerns with the proposal.The proposal will reduce the opportunity that Stakeholders currently have to review and comment on standard revisions. The PPL Companies would like the Standards Committee to consider that eliminating the 30-day informal comment period doesn't provide Stakeholders with the same level of involvement in the standards process as they enjoy today. Given the often technical nature of standards and differences by region and/or company structure, the use of the informal comment period and the 30-day formal comment period has proven effective. The PPL Companies recommend that existing utilization of both informal and formal comments periods be required and the time periods be maintained.NERC's current process, which is ANSI compliant, provides that the SDT must address all comments directly. The proposal provides the SDT with ability to selectively

Organization	Yes or No	Question 1 Comment
		group comments and respond with a generic statement. The PPL Companies suggest that if a response is to be used multiple times to respond to similar comments from different entities, the response should cite which specific previous response it is referencing rather than just stating, "response above." The PPL Companies recommend that the SDT be directed to continue to provide direct responses back to each comment or accurately reference which response the SDT feedback is referencing, when grouped responses are submitted. This recommendation does not preclude SDTs from responding to similar comments in a similar manner by using the same response multiple times.

Response: Thank you for your comments and support. First, there is no intention to reduce the opportunities that stakeholders have for input; instead, the use of informal forms of input are encouraged so that before a standard is posted for a formal comment period, the drafting team has a good idea that it has uncovered all of the major technical issues and has a draft that is "final." After the 45-day formal posting, every comment will be responded to by the drafting team. The drafting team has the ability to bundle responses if the comments from different stakeholders address the same issues. This process is included in the new Section 4.12 which is replacing the previous Sections 4.12 of the draft SPM:

4.12: Consideration of Comments

If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot.

There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot.

Organization	Yes or No	Question 1 Comment
ACES Power Marketing Standards Collaborators	Yes	
SPP Standards Review Group	Yes	
Arizona Public Service Company	Yes	
Oklahoma Gas & Electric	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Public Service Enterprise Group	Yes	
City of Austin dba Austin Energy	Yes	
FirstEnergy Corp	Yes	
ReliabilityFirst	Yes	
Trans Bay Cable LLC	Yes	
Essential Power, LLC	Yes	

2. **As noted in Question 1, SPIG Recommendation 1 states that NERC should continue to meet the minimum requirements of the American National Standards Institute (ANSI) process to preserve ANSI accreditation. Currently, the NERC standards development process exceeds the minimum ANSI requirements in two areas that involve the treatment of Negative (No) ballots (ballots "rejecting" a standard or standards-related item, both with and without comments):**

   a. **The NERC Standards Development Process considers negative votes with comments (regardless of the nature of the comment or if the comment is even relative to the standard being balloted) in both the determination of quorum and in calculating industry consensus.**

   b. **The NERC Standards Development Process considers negative votes without comments in the determination of quorum and in calculating industry consensus.**

   ANSI requirements consider negative votes with comments related to the proposal under consideration in determining quorum and the calculation of industry consensus. However, ANSI requirements do not require the consideration of negative votes accompanied by comments that are not related to the proposal under consideration, or negative votes without comments in determining industry consensus. ANSI requirements allow for negative votes to be considered only in the calculation to determine quorum.

   Thus, in the revised Standard Processes Manual, negative votes that are submitted without comment, or that are submitted with a comment unrelated to the posted standard, will be included in the determination of quorum but will not be included in the determination of consensus. Stakeholders will be given explicit guidance on submitting constructive comments to drafting teams, and they will be given an explanation if their vote and associated comment are not included in consensus (with the opportunity to appeal). This change ensures that stakeholders are encouraged to offer constructive feedback that drafting teams can use to improve draft standards and reach consensus efficiently.

   Does this proposed revision adequately address SPIG Recommendation 4? If not, please explain why and offer an alternative solution for improving the timely development of standards while maintaining ANSI accreditation.

Summary Consideration:

The Standards Committee Process Subcommittee's (SCPS) goal with this particular revision to the Standards Process Manual (SPM) is addressing several issues identified in the SPIG (Standards Process Improvement Group**)** Recommendations: 1. (*SPIG Recommendation 1 & 5*) the alignment of the ERO Standard Development Process with the ANSI requirements. A key objective in the SPIG recommendations was to ensure that ANSI accreditation is maintained for the process. ANSI currently takes the same approach with 'No" ballots and comments as the proposal incorporated in the draft revisions to the SPM. Close alignment with the ANSI standards will ensure accreditation is maintained. 2. (*SPIG Recommendation 5)* The SPIG recommendations identified a need to shorten the ERO Standard Development Process and it is the opinion of the SCPS that the best way to accomplish this is provide the Standard Drafting Teams (SDT) with the best opportunity to build stakeholder consensus. In order to accomplish this, stakeholders need to be fully engaged early in the process and need to provide meaningful comments that are helpful and constructive, which will assist the SDT in developing revisions that are responsive to the concerns of the industry and establish an adequate level reliability. It has been demonstrated in the past that early engagement of stakeholders in the process produces higher quality standards in a shorter amount of time.

Based on the comments received, the SCPS has re-examined this issue and determined that the approach for evaluating the relevance of comments requires additional clarification and has eliminated the process for reviewing the relevance of comments from the proposed revisions. However, the SCPS has retained the concept of including 'No' ballots that are not accompanied by comments in the calculation of quorum but not being counted in the calculation of consensus.

With respect to making modifications to NERC's balloting software to provide a set of standard options for balloters to choose from to indicate the reason for a 'no' vote, the Standards Committee does not believe it is appropriate to provide specific details about NERC's balloting software in the SPM. Ultimately, NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff will be prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question. For this reason, SPM revisions will not contain details such as those in the SPIG recommendation.

In the revised balloting software that will be implemented to support a revised process, all of the options for casting a vote, and how each is counted in the determination of a quorum and in the weighted segment approval will be clearly articulated so that the entity casting the vote is fully aware that submission of helpful comments to the drafting team is critical to a successful stakeholder process for standards development. The website will clearly indicate how votes are considered and counted towards consensus and quorum.

Organization	Yes or No	Question 2 Comment
Dominion	No	The preceding discussion appears to focus on the ANSI process ascribed in SPIG Recommendation 1 while the question asks about Recommendation 4The four bullets under SPIG Recommendation 4 are not adequately addressed in the revision to the process manual. Dominion believes the ballot process and comment process should be structured in such a way that there is direct linkage between the vote (ballot) and the comments associated with the vote.
Response: The SCPS recognizes that the question asked in the comment form incorrectly identified this revision with Recommendation 4 from the SPIG report. The revisions associated with the 'No Ballot' issue are in response to recommendations 1 & 5. It is the SCPS's intent to enhance the information provided to the Standard Drafting Teams ("SDT") with helpful and constructive input to allow the team to efficiently revise a standard during its development to meet industry concerns. Based on the comments received, the SCPS has re-examined this issue and determined that the approach for evaluating the relevance of comments requires additional clarification and has eliminated the process for reviewing the relevance of comments from the proposed revisions. However, the SCPS has retained the concept of including 'No' ballots that are not accompanied by comments in the calculation of quorum but not being counted in the calculation of consensus. The SCPS believes stakeholders that vote 'No' without comment are not providing enough information to assist the SDT in revising the standard to reach consensus. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. In the revised balloting software that will be implemented to support a revised process, all of the options for casting a vote, and how each is counted in the determination of a quorum and in the weighted segment approval will be clearly articulated so that the entity casting the vote is fully aware that submission of helpful comments to the drafting team is critical to a successful stakeholder process for standards development. The website will clearly indicate how votes are considered and counted towards consensus and quorum. With respect to a linkage between the vote and comments associated with the vote, this information is available to drafting teams now and will be in the future (and this capability is not dependent on software redesign or a comment box being on the same screen as the ballot that is cast). NERC staff will be prepared via software or manual methods if necessary, to ensure that option 2 can be implemented so that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, and the linkage between the comment and ballot will be available.		
ACES Power Marketing Standards Collaborators	No	-1- In general, we disagree with the concept of not counting some negative votes. We believe all votes should be counted towards the approval rate. While it is true

Organization	Yes or No	Question 2 Comment
		that ANSI allows negative votes to not be counted, it is not appropriate, in NERC's case, to lower its current criterion to the minimum ANSI criterion. First, the current NERC criterion simply exceeds the minimum ANSI criterion and is not a violation of ANSI criteria. Second, ANSI-approved standards setting bodies develop standards that are followed for different reasons than NERC standards are. For instance, Underwriting Laboratories develops laudable standards for safety testing and certification. If UL standards are not met, a product cannot use the UL label which might affect its ability to be sold or have other ramifications. UL cannot fine the manufacturer for not following a UL standard. Third, we are not aware of any other ANSI-approved standards setting body that has the authority to enforce those standards with fines of up to $1,000,000/day/violation. Fourth, NERC having the ability to not count a negative vote, ultimately leading to a standard becoming approved and enforceable by NERC, is a conflict of interest. For these reasons, it makes sense to continue to exceed the ANSI requirement. Exceeding this ANSI requirement would also be consistent with the SPIG recommendation to continue to maintain ANSI accreditation. -2- With regard to negative votes without comment or with unrelated comments – it does not seem proper to allow these votes to count toward quorum but not toward approval. Achieving quorum tells you that there was a large enough proportion of the body that voted and had their opinion represented, but then a portion of those opinions (the negative without comment votes) are not represented. This is not a true quorum. We believe that negative votes without comment or with unrelated comments should be counted toward both quorum and approval. But if they must not be counted toward approval, then they should also not be counted toward quorum. In such a case, quorum should be recalculated after certain negative votes have been eliminated. -3- If negative votes are not to be counted, then a high bar should be established for the decision to not count the vote. If there is any doubt whether a comment is

Organization	Yes or No	Question 2 Comment
		related, then the voter should be given the benefit of the doubt, and the vote should be counted. We believe the proposed changes do have a fairly high bar (not considering our comment regarding quorum in comment 2 of this question). However, we further suggest that the primary emphasis should be on encouraging voters submitting negative votes to provide comments rather than on recalculating the ballot. For one, it is entirely possible that recalculation of the ballot will not change whether the standard is approved or not. Obviously, in this case, recalculation of the ballot provides no expedition of the standards development process. -4- As we understand the standards process, comments are no longer submitted with the ballot, but through a separate electronic formal comment process. We assume that these formal comments will be used to determine whether a negative vote was accompanied by a related comment and should count toward calculating approval. We also understand that the standards process only requires that there be one formal comment period during the entire balloting process of a standard. So in the case where a ballot results in a standard achieving approval and it proceeds to recirculation ballot (with no formal comment opportunity), then a voter who did not initially provide comments will not have the opportunity to provide comments in the recirculation ballot period to allow their negative vote to count. We suggest that the standards process allow the opportunity to provide comments, whether formal or not, at each voting opportunity so that each voter has the chance to cast a vote that will be counted. Preferably, voting and commenting should occur simultaneously as it previously had been conducted. This will further ensure that the drafting team is incented to work to gather input rather than discount negative votes. Additionally, we understand that on p. 24 of the whitepaper for this project it states that the NERC website will be rebuilt with a revised balloting page, but we still feel that the actual standards process manual should clearly reflect these elements of the balloting process. -5- Comments simply disagreeing with the need for a standard should be

Organization	Yes or No	Question 2 Comment
		considered an acceptable comment for a negative vote and the process manual should state this directly. First, the SAR is not balloted, so there is no measurable way to indicate whether there is majority support for the standard development activity. Second, the drafting team essentially makes a judgment from comments on whether the SAR has support to proceed. Historically, standards drafting teams have not been able to gauge the level of support for a standard from comments. This can be easily deduced by the fact that the vast majority of standards usually do achieve a very low number of affirmative votes during the initial ballot. For whatever reason, it is only when the standard becomes balloted that support becomes measurable. Thus, commenters could state many objections to the SAR in the comment period, and it still proceeds based on the drafting team's judgment that such comments did not relate.

Response: The SCPS does not understand why the commenter feels that this proposed revision to the SPM is not appropriate for the electric utility industry. It is NERC's intent to enhance the information provided to the SDT with helpful and constructive input to allow them to efficiently revise a standard during its development to meet industry concerns. The revisions associated with the 'No Ballot' issue are in response to recommendations 1 & 5. It is the SCPS's intent to enhance the information provided to the Standard Drafting Teams ("SDT") with helpful and constructive input to allow the team to efficiently revise a standard during its development to meet industry concerns. Based on the comments received, the SCPS has re-examined this issue and determined that the approach for evaluating the relevance of comments requires additional clarification and has eliminated the process for reviewing the relevance of comments from the proposed revisions. However, the SCPS has retained the concept of including 'No' ballots that are not accompanied by comments in the calculation of quorum but not being counted in the calculation of consensus. The SCPS believes stakeholders that vote 'No' without comment are not providing enough information to assist the SDT in revising the standard to reach consensus. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are.

In the revised balloting software that will be implemented to support a revised process, all of the options for casting a vote, and how each is counted in the determination of a quorum and in the weighted segment approval will be clearly articulated so that the entity casting the vote is fully aware that submission of helpful comments to the drafting team is critical to a successful stakeholder process for standards development. The website will clearly indicate how votes are considered and counted towards consensus and quorum.

Organization	Yes or No	Question 2 Comment
With respect to a linkage between the vote and comments associated with the vote, this information is available to drafting teams now and will be in the future (and this capability is not dependent on software redesign or a comment box being on the same screen as the ballot that is cast). NERC staff will be prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, and the linkage between the comment and ballot will be available. The website will clearly indicate how votes are considered and counted towards consensus and quorum. The website is expected to provide a ballot pool member with the ability to enter comments and reference comments provided by other ballot pool members.		
Northeast Power Coordinating Council	No	It addresses the recommendations, however we do not necessarily agree with the approach taken. The revision doesn't address when an entity refers to comments submitted by another entity. For example, NPCC votes "no" with relevant comments, and an entity votes "no", and indicates a reference those comments submitted by NPCC.
Response: The SCPS appreciates the support of the proposed revisions to the SPM. NERC already encourages entities to express support for the comments of another entity if they do not have any additional comments to add, although this is not expressly mentioned in the SPM. NERC has recently implemented a change to the standard commenting form to provide a stakeholder with the ability to indicate support for comments provided by other commenters.		
IRC-SCR	No	We have strong concerns with discounting negative votes without comments or the rejection of ballots for unrelated comments. Ultimately an individual has the right to say a standard is not needed and that no amount of tweaking will make it acceptable. The voting section is very confusing regarding abstentions and how these are accounted for in either the quorum or approval calculations. The confusion would be minimized if the current process was not changed. There was intermingling of "calendar days" and "business days" in this section. We believe the ballot body should get 10 business days to vote.
Response: The SCPS agrees with the commenter that an individual has the right to provide comments that indicate a 'standard is not needed or that no amount of tweaking will make it acceptable', provided the individual provides justification for the comments. Therefore the identified comments will in fact be counted by the latest proposal and the next revision of the manual will reflect this.		

Organization	Yes or No	Question 2 Comment
If the process revisions are implemented, the balloting website will clearly indicate how votes are considered and counted towards consensus and quorum. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS has an obligation to be responsive to the SPIG recommendations and to maintain the 'status quo' is not responsive nor does it address the concerns with SDTs having the ability to develop quality standards in a timely fashion that achieve industry consensus. The SPCS also believes that the current time requirements associated with the individual steps within the standard development process are necessary to minimize the time required for the development of standards. Extending the ballot window from 10 calendar days to 10 working days would be counter to the SPIG recommendations which are calling for improvements to shorten the process.		
Hydro One	No	Hydro One disagrees with the proposed approach for the treatment of negative votes without comments or with comments that are judged to be unrelated to the standard.We believe that while it is desirable for SDTs to know what the objections are, negative votes should be always counted for both the quorum AND the consensus result. The approach should be one of reaching out to the members with negative votes giving them ample opportunity to explain. This can be done through direct contact, modifications to the balloting software, immediate access to the comments submitted by others so they can concur and agree, etc.We recognize that some safeguards were added to the proposed SPM to allow for some of the above. However, in order to make it appear fair, a review/report/appeal process was added. The result is that ballot results will not be final until such process is completed, which could in certain cases take several months. The above will introduce delays that could in cases more than offset any time gains obtained by the efficiencies introduced in other parts of the process. We believe the ballot process must be open, simple and efficient. If the reaching out and communication initiatives mentioned above are implemented, we see no reason to change the way ballots are currently counted, that is, count ALL negative votes, including those without comments in the consensus results.If the proposal is implemented, we request that (a) software is modified to allow check-boxes to be used to indicate objections; (b) access to comments submitted by others immediately after received; (c) software should accept as valid concurrence with comments submitted by other entities; (d)

Organization	Yes or No	Question 2 Comment
		opportunity to submit comments during recirculation ballots which currently does not exist. It also raises the question on hat Criteria constitute a valid interpretation being used by NERC Standards and Legal Staff?
Response: It is NERC's intent to enhance the information provided to the SDT with helpful and constructive input to allow them to efficiently revise a standard during its development to meet industry concerns. The SCPS believes that the informal and formal comment periods and the ballot periods provide the industry with ample opportunity to clearly articulate their potential opposition to a standard action. Requiring SDTs to reach out to individual negative balloters to further assess their concerns would be counterproductive to the SPIG recommendations and would significantly lengthen the development process. With respect to making modifications to NERC's balloting software to provide a set of standard options for balloters to choose from to indicate the reason for a 'no' vote, the Standards Committee does not believe it is appropriate to provide specific details about NERC's balloting software in the SPM. Ultimately, NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff will be prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question. For this reason, SPM revisions will not contain details such as those in the SPIG recommendation. NERC is considering implementing software changes that will allow an entity's comments to be visible immediately, but the current software tools used for commenting on standards projects do not allow this to be done at the current time. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process. Regarding criteria for what constitutes a valid interpretation request, NERC must rely on guidance from the NERC Board of Trustees, which issued guidance at its November 2009 Board meeting.		
AECI and the G&T members Central Electric Power Cooperative, KAMO Power Cooperative, M&A Electric Power Cooperative, Northeast	No	AECI and its' member G&T understands the reasoning for the desired change to the balloting process. However, we disagree with the changes that exclude negative votes without comment. AECI believes this process will not reduce the time to get a standard to BOT for approval. In fact with all the potential appeals and the process associated with the appeals process it will take longer for a standard to get to the

Organization	Yes or No	Question 2 Comment
Electric Power Cooperative, NW Electric Power Cooperative, and ShoMe Power Electric Cooperative		BOT for approval. If "NO" votes w/o comment are not counted they should not be counted to create a quorum. On a side note; other means to assist voters to include a no vote reason have not been proposed here even though they were discussed. The current NERC balloting process is objectionable and does not provide an adequate means to include a reason for a negative ballot. NERC has not demonstrated nor communicated adequately that this issue can be adequately managed, therefore, No votes should count.

Response: It is NERC's intent to enhance the information provided to the SDT with helpful and constructive input to allow them to efficiently revise a standard during its development to meet industry concerns. The proposed revision of counting 'No' ballots toward quorum provides alignment with the ANSI requirements and supports NERC's ability to maintain ANSI accreditation, which is directly responsive to SPIG Recommendation 1. The SCPS has re-examined this issue and determined that the drafted criteria for comment evaluation requires additional clarification and will be eliminated from the proposed revisions. However, the SCPS will continue to pursue the concept of 'No' ballots that are not accompanied by comments or referenced to comments not being counted in the calculation for consensus, but will however be included in the calculation of quorum.

With respect to making modifications to NERC's balloting software to provide a set of standard options for balloters to choose from to indicate the reason for a 'no' vote, the Standards Committee does not believe it is appropriate to provide specific details about NERC's balloting software in the SPM. Ultimately, NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff will be prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question. For this reason, SPM revisions will not contain details such as those in the SPIG recommendation.

The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process.

Finally, the appeals process in the SPM is a general appeals process that applies to every aspect of the process, and it is not necessary to reference the right to appeal in every section of the manual.

Organization	Yes or No	Question 2 Comment
MRO NSRF	No	The NSRF believes that SPIG Recommendation #4 for "Negative Votes" without comments was not addressed in the revisions to the SPM as stated in the SPIG Report below:Ballot process shall: o Provide options for voting "No" with guiding choices for the answer with a comment section on the ballot. ----------Furthermore, with a dropdown menu in place, Section 4.11 Voting Positions appeals process regarding negative ballots is not needed and should be deleted.
Response: It is NERC's intent to enhance the information provided to the SDT with helpful and constructive input to allow them to efficiently revise a standard during its development to meet industry concerns. With respect to making modifications to NERC's balloting software to provide a set of standard options for balloters to choose from to indicate the reason for a 'no' vote, the Standards Committee does not believe it is appropriate to provide specific details about NERC's balloting software in the SPM. Ultimately, NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff will be prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question. For this reason, SPM revisions will not contain details such as those in the SPIG recommendation.		
Florida Municipal Power Agency	No	FMPA supports the concept of only counting "no" votes with related comments; however, FMPA checked the "no" box because we are concerned for how the Final Ballot will be conducted. The wording of Section 4.15 and Section 4.13 seems to conflict with the ability to comment with a "no" vote on the final ballot, especially in the case where an entity changes from a "yes" vote to a "no" vote, how will they be allowed to submit a related comment since Section 4.13 states that there will be no formal comment period with the Final Ballot?Typo, this issue was identified in SPIG Recommendation 5, not 4.
Response: Thank you for your comments and support. NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff will be prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate		

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support for another entity's comments without the need to submit full responses to every question. For this reason, SPM revisions will not contain details such as those in the SPIG recommendation.		
SERC Planning Standards Subcommittee	No	We disagree with the process changes that exclude "no" votes for whatever reason. We believe the existing commenting and balloting process is efficient at developing consensus.
Response: It has been identified that the NERC standards development process could be made more efficient. The SPIG solicited the industry in response to these concerns and developed the recommendations to address them. The SCPS has an obligation to be responsive to the SPIG recommendations and to maintain the 'status quo' is not responsive nor does it address the concerns with SDTs having the ability to develop quality standards in a timely fashion that achieve industry consensus. It is NERC's intent to enhance the information provided to the SDT with helpful and constructive input to allow them to efficiently revise a standard during its development to meet industry concerns. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process. In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval.		
Edison Electric Institute	No	The handling of 'no' votes is a matter that has attracted significant attention. SPIG recommended that the ballot process should use all votes to establish quorum, and provide options for 'no' votes, including changes to the balloting and commenting process that would help useful comments. For example, many comments will briefly state a broad negative comment without showing the specific language of concern, or offering a constructive alternative that the commenter could support.The proposed process change is to disallow simple 'no' votes without comments for purposes of determining final ballot counts. It appears that the logic that moves from the SPIG recommendations to the process proposal to disallow simple 'no' votes is

Organization	Yes or No	Question 2 Comment
		based on the premise that ANSI requirements do not require consideration of 'no' votes without comments and since NERC seeks only to maintain minimum ANSI requirements, this process element is unnecessary.EEI cannot support the proposal. We understand that SPIG seeks to move the process in the direction of having the balloting and commenting process to provide as much substantive feedback as possible. Irrelevant comments or negative votes unaccompanied by comments do not offer helpful feedback, however, it should be a relatively simple matter to address such comments very quickly. EEI recommends that appropriate software changes be designed and implemented as soon as possible that will help gather more focused comments. A simple 'no' vote should be allowed to count both for determining quorum and final ballot count. Finally, somehow we need to find a way to work around the apparent timing issues for making necessary software changes. This should not be a binding constraint on making these important process changes.

Response: Gains in efficiency are sometimes incremental in nature. Although it may be true that answering a unrelated comment or superfluous comment may be relatively straightforward and quick it is nonetheless not helpful and uses resources that could be better used elsewhere. It is NERC's intent to enhance the information provided to the SDT with helpful and constructive input to allow them to efficiently revise a standard during its development to meet industry concerns. It is NERC's intent to enhance the information provided to the SDT with helpful and constructive input to allow them to efficiently revise a standard during its development to meet industry concerns. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process.

In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with

Organization	Yes or No	Question 2 Comment
participation in the standards development process. With respect to making modifications to NERC's balloting software to provide a set of standard options for balloters to choose from to indicate the reason for a 'no' vote, the Standards Committee does not believe it is appropriate to provide specific details about NERC's balloting software in the SPM. Ultimately, NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff will be prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question. For this reason, SPM revisions will not contain details such as those in the SPIG recommendation, and NERC agrees with EEI that the timing of software changes should not be a limiting factor in moving forward with process improvements..		
Arizona Public Service Company	No	Elimination of negative votes of any kind in calculating industry consensus will be a mistake. Particularly elimination of negative votes with comments considered to be not relevant. There are no defined criteria as to what is a relevant comment and the determination will be subjective. If two thirds of the members do not vote affirmative, the standard should not pass. Eliminating the negative votes without comments or with comments not considered to be relevant could result into a standard which has great deficiency. If a voting member votes no, it should be counted no matter what
Response: It is NERC's intent to enhance the information provided to the SDT with helpful and constructive input to allow them to efficiently revise a standard during its development to meet industry concerns. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process. In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval.		
Occidental Energy Ventures	No	Industrial Consumers are very concerned that entities that submit "No" votes without

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Corp. (OEVC) and Electricity Consumers Resource Council (ELCON) together called Industrial Consumers		any explanation may slow the development of certain standards. However, there is also a concern for Stakeholders that represent several affiliated NERC Registered Entities; while one Entity may be registered in the Ballot Body, the comments may be submitted under another Affiliate or through a Trade Association. There needs to be a way to add a comment in the voting process to state "see comments submitted under Company XYZ for this ballot". Similarly, there needs to be a linkage between comments provided during the review and the balloting applications. An automated solution makes the most sense and should save time and effort required by the Project Team and Industry Stakeholders alike. In addition, we are concerned that a project team can reject a commented "No" vote because the answer does not align with the question as written. We agree with the general need to ensure that negative feedback is helpful. Industrial Consumers also are very aware of the significant effort the Standards Committee Process Subcommittee (SCPS) has been taking in an attempt to develop a process by which "No" votes are considered without slowing the process. Industrial Consumers compliment the SCPS for its efforts and point out the complexity of this issue. Industrial Consumers are concerned that if this issue is not resolved to the satisfaction of all stakeholders, it could result in the rejection of the entire process. Thus, Industrial Consumers urge the Standards Committee to be very cautious in recommending SPM changes until the SC is sure that stakeholders are comfortable with the proposed changes. Industrial Consumers are not convinced that the language in the proposed changes to the SPM will be acceptable to all stakeholders.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process.		

Organization	Yes or No	Question 2 Comment
With respect to making modifications to NERC's software - ultimately, NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff will be prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question. For this reason, SPM revisions will not contain details about software.		
National Rural Electric Cooperative Association (NRECA)	No	While NRECA agrees it would be helpful if "negative" votes included some form of written support, we are concerned that judgment of whether a comment with a "negative" vote is adequate is likely to be very subjective. It will be a difficult and subjective exercise for SDTs and/or NERC to judge whether a "negative" vote comment is good enough for that vote to be counted towards the ballot result. While the process in the draft SPM provides the "negative" balloter the opportunity to provide a comment after the ballot is concluded that will allow for their vote to be counted, NRECA is concerned that the proposed SPM revisions in this topic area will be very difficult to implement without a significant number of appeals being submitted. To complicate matters, currently a balloter cannot submit a comment with an "affirmative" or "negative" vote. NRECA is not sure of the reason for this current limitation and asks when will this be corrected? Based on the preceding statements, NRECA requests that the proposed modifications to the SPM related to "negative" ballots without comment, or related comment, be deleted. At this time we believe staying with the current process is better than making changes that could be problematic.NRECA also requests clarification regarding the reasoning for removing abstentions from counting toward quorum.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated		

Organization	Yes or No	Question 2 Comment
with participation in the standards development process. With respect to making modifications to NERC's balloting software - ultimately, NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff will be prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question. For this reason, SPM revisions will not contain details about software. The method for determining quorum has been corrected to include abstentions as the current SPM does.		
Liberty Electric Power	No	Serious ethical questions arise when individuals with an interest in passing a standard decide whether a comment is "related". All negative votes should count in the balloting. Should the concept of requiring a comment survive, the manual should be modified to allow any comment for the purpose of counting the vote as a negative in the ballot calculations. There have been many cases where a comment has been rejected as beyond the intent of the SDT. These comments are germane, but are subject to rejection. Removal of subjective decisions on the validity of comments is the only fair practice.
Response: The SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval.		
Manitoba Hydro	No	The proposed revision does not address Recommendation 4, as it does not address the issues of results-based standards, cost-effectiveness of standards, alignment of RSAWs with standards or retirement of unnecessary standards. The proposed revision simply encourages constructive feedback, which may facilitate achieving "consensus", since "consensus" will essentially be redefined to exclude certain negative voters. It does not address Recommendation 4.
Response: The SCPS recognizes that the question asked in the comment form incorrectly identified this revision with Recommendation 4 from the SPIG report. The revisions associated with the 'No Ballot' issue are in response to recommendations 1 &		

Organization	Yes or No	Question 2 Comment
5.		
Con Edison	No	The revised manual needs to clarify the treatement of negative votes. For example, if an entity votes negative and references concensus comments submitted by their Regional Entity, this negative vote should be counted towards determining industry consensus. We note that in the existing ballot process there are no longer text boxes with the ballot, so how would the comment status of a ballot determined? Who decides what comments are constructive, appropriate and related (an acceptable comment) and which are not (inappropriate and unrelated)? Is there an appeal process? The SPIG must ensure that negative votes are not inappropriately disenfranchised.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process. With respect to NERC's balloting software - ultimately, NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff are prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question. In the current process, NERC can and does manually correlate comments with ballots (including comments submitted by affiliated entities – NERC must maintain an awareness of which entities are 'affiliated' in order to maintain the Registered ballot Body in accordance with the Rules of Procedure). For this reason, SPM revisions will not contain details about software.		
Kansas City Power & Light	No	Although the proposed changes reflect the ANSI process, this proposal to dismiss negative votes that have no comment or are deemed to have unrelated comments

Organization	Yes or No	Question 2 Comment
		does not reflect a representative process nor respects industry guidance. Further the "due process" that is proposed for entities to "appeal" the dismissal of a negative vote will unnecessarily burden the ballot process and result in a delay of determining industry consensus. In addition, the determination of whether a negative comment has merit will take time from the SDT and distract the SDT from the more fruitful activity of developing the standard and requirements. Recommend the current voting process remain and the proposed voting process not be implemented.
Response: The SCPS has an obligation to be responsive to the SPIG recommendations and to maintain the 'status quo' is not responsive nor does it address the concerns with SDTs having the ability to develop quality standards in a timely fashion that achieve industry consensus. In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process.		
Texas Reliability Entity	No	Further clarification about when "No" votes will not be counted should be provided, per the discussion at the July Standards Committee meeting. In particular, it should be clear that any relevant comment will be accepted and the corresponding vote will be counted. Would a comment like "This standard provides no reliability benefit" be sufficient?
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval.		

Organization	Yes or No	Question 2 Comment
American Electric Power	No	Regarding SPIG looking into the issue of "no votes without comments", it needs to be determined exactly why these kinds of votes are being cast and what challenges they might be causing. This needs to be fully understood and communicated before any solution is proposed and discussed. Until that is accomplished, we are unable to determine whether or not the proposed changes are the best course of action. In addition, we are very uncomfortable with the concept of somehow counting "no votes without comments" toward the quorum, and yet not count them towards the vote count itself. In essence, these votes would be counted as abstaining votes. It would be unacceptable to assign "no votes without comments" a different applicability or weight than "yes votes without comments", as in the manner proposed.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval. The proposed revision of counting 'No' ballots toward quorum provides alignment with the ANSI requirements and supports NERC's ability to maintain ANSI accreditation, which is directly responsive to SPIG Recommendation 1. The SCPS believes that there is a distinct difference between a 'Yes' vote without comments and a 'No' vote without comments. The 'Yes' vote essentially is signifying agreement with the proposed standard action and a 'No' vote signifies or indicates disagreement with the proposed standard action. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are.		
Pepco Holdings Inc.	No	Only NO votes without any comments should not be included in the determination of outcome. If a NO vote has any comment it should be included in the quorum and the calculation.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count		

Organization	Yes or No	Question 2 Comment
toward achieving a quorum and the calculation of the approval.		
NextEra Energy Inc	No	NextEra generally favors a clear bright line that only discounts a "no" vote when no comments are submitted.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval.		
Flathead Electric Cooperative, Inc.	No	I can't support the voting change even if it may still comply with ANSI standard development requirements. The ANSI process is generally used for voluntary standards rather than for mandatory/sanctionable standards, so that going above and beyond the ANSI process to provide a broad unfettered voting pool is appropriate. Requiring "related" comments with a negative vote, but not a positive vote dilutes the voting pool for those that disagree with the proposal. Tasking drafting teams with making this distinction of what is "related" seems problematic at best. In addition, this change could violate the due process mandate in Section 215 of the FPA requires NERC "provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties" Allowing the drafting team to omit any negative vote and comment it deems not "related" does not appear to pass either a "due process" or a "balance of interests" test.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval.		
Public Service Enterprise Group	No	First, we ask whether last paragraph above should have referred to Recommendation 1 instead of Recommendation 4. Second, with the objective of maximizing

Organization	Yes or No	Question 2 Comment
		transparency, we would like to see the ballot results posted to show which ballots were rejected that meet the criteria for not counting "Negative" ballots. We believe that this information should be made public as soon as possible after the ballot window closes, even though the process in Section 4.11 for addressing a negative ballot may not be completed. If this change is made to the SPM, we would agree with the treatment of "Negative" ballots.
Response: The SCPS recognizes that the question asked in the comment form incorrectly identified this revision with Recommendation 4 form the SPIG report. In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval.		
Illinois Municipal Electric Agency	No	A "No" vote should be included in both the determination of quorum and determination of consensus regardless of submittal of comment. In order to achieve better use of NERC and registered entity resources, and timely adoption of better reliability stnadards, the SDT should not be spending time asessing whether a comment is related to the proposal under consideration; i.e., critiquing the quality of a comment. NERC should also not be spending resources to develop tools to link a ballot pool member's vote to comments. The separate comment process should be adequate to provide the SDT constructive input and improve timely stakeholder consensus. If a ballot pool member appears to be abusing the ballot process, this can be addresse through other means.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval.		
Duke Energy	No	This change goes beyond the SPIG proposal to "provide options for voting no with guidance choices for the answer with a comment section on the ballot." Providing

Organization	Yes or No	Question 2 Comment
		comments is undoubtedly important to facilitating the SDT in crafting a standard that advances reliability, and increases the probability that the industry will develop the requisite consensus. For these reasons Duke Energy offers support for NERC's efforts to educate the industry on the importance of providing comments and efforts to facilitate that commenting through voting software changes. An entity's prerogative to have their vote counted, however, should not be dependent on their submittal of what are judged "related" comments.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process. With respect to NERC's balloting software and "providing options for voting no with guidance choices for the answer with a comment section on the ballot" - ultimately, NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff are prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question. In the current process, NERC can and does manually correlate comments with ballots (including comments submitted by affiliated entities – NERC must maintain an awareness of which entities are 'affiliated' in order to maintain the Registered ballot Body in accordance with the Rules of Procedure). For this reason, SPM revisions will not contain details about software.		
FirstEnergy Corp	No	1. Although FE agrees that "No votes without comments" do not help the drafting team in the development of the standard and believes all balloters should provide a comment, we do not agree with discounting "No Votes without comments" for ballot approval while counting "No Votes without comments" in calculation of the quorum. Although this meets ANSI, we believe NERC should not adopt this proposal. 2. It may

Organization	Yes or No	Question 2 Comment
		be a slippery slope to allow drafting teams to judge whether or not a comment accompanying a negative vote is relevant. Allowing this provision will only have the potential to create controversy among the industry, the drafting teams, and NERC and will not enhance the process. Although FE believes all votes should be relevant in determining ballot outcomes, at a minimum only "No votes without comments" should be excluded. This removes the subjectivity that is introduced when assessing the relevance of a provided comment. Additionally, the process described will prolong a standard development process which is already scrutinized for its ability to timely produce standards. The changes include an additional 40 days allotted for the SDT to inform NERC staff/Legal of negative votes with unrelated comments (and without comments) and the time afforded the balloter to adjust their comments. 3. The statements in sec. 4.11 are troublesome and should be revised. In the bullet item for "Negative with related comments" it states that "Comments should include guidance/input to the drafting team that would assist efforts that would make revisions to the Reliability Standard acceptable and enable an affirmative vote in a subsequent ballot." Although we tend to agree with this, it should not be mandated and suggest changing the phrase "comments should include" to "comment are encouraged to include"4. The voting process adopted by NERC will need to be adequately communicated to industry through education such as webinars so that industry ballot body members are clear on the final rules whatever they may be..
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval. Thank you for your suggestion concerning industry education. It will be considered when the process revisions are approved and prior to the implementation.		
Ameren	No	(1) We do not agree with the SDT's proposal; the subjectivity in determining whether a set of comments received with a "NO" vote are relevant or not would be

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		problematic. At the very least, a provision is essential for those providing "NO" votes to see how their comments are handled, and for formally addressing any disregarding of such comments on grounds of irrelevance and thereby not counting "NO" vote for consensus.(2) We believe it is reasonable for SDT to expect a reason for voting "NO"; however, as the SPIG has suggested (See Page 14) - the SDT should provide guiding choices to help with the "no" vote. In this respect we suggest the SDT to provide details on this guidance. (3) In instances where, "NO" votes are disregarded for purposes of determining consensus on a standard, an extreme scenario would be where there is a little industry support for a given standard, yet it becomes an approved standard anyway. (4) We believe that 'No' votes should be considered, even if comments are not included, because everyone will need to live with standards which receive approval. (5) If the SDT recommends to discount "NO" votes for consensus, then we would request the SDT to provide details of the Appeals process.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval.		
Indiana Municipal Power Agency	No	IMPA believes that all votes should be considered when developing industry consensus on a NERC standard. If an individual from an entity takes the time to cast a vote it should be counted, regardless if it has comments or comments that are deemed not related to the proposal under consideration. An individual may not comment for a number of reasons such as a lack of time at that particular instance or they may be voting against a standard for a reason they wish not to disclose or be made public. IMPA views not counting negative votes with comments that are unrelated to the standard or interpretation as problematic. An entity may submit a comment that in their view pertains to the standard under consideration and yet NERC may consider it not related. IMPA understands there is an appeal process of the decision not to count a "no" vote with comments, but for something as fundamental as a right to cast a vote in one entity's own opinion, then having to

Organization	Yes or No	Question 2 Comment
		justify it against a potentially subjective determination is not an improvement of the process. Another point that weighs in our comment is the extra time that it would entail to appeal a rejection of a "no" vote comment on both the entity's and NERC's side. An entity may not choose that route due to time constraints already encountered due to the large volume of reliability standard work on everyone's plate. Therefore, IMPA supports counting all votes casted on a proposal under consideration and believes this to be the best solution for the timely development of standards. By not counting "no" votes with unrelated comments, an appeal process is added and could potentially hold up the standard process, especially if there is a relative high number of them.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval.		
American Transmission Company	No	ATC's comments are a repeat of its comments from question 1.Ballot process shall: o Provide options for voting "No" with guiding choices for the answer with a comment section on the ballotThis item was a major discussion point for SPIG and it is not addressed in the proposed SPM. We remind the group modifying the SPM, that the reason for the recommendation is to insure that every "no" vote would have a comment, which eliminates the need for determine if votes should be counted. Because the modification did not incorporate this recommendation completely the team has both rehashed the discussion that took place under SPIG and had to include unnecessary language about appealing "no" votes with comments. The SPIG solution must be incorporated into the SPM In addition to the above comment, we have concerns with the way the team interpreted this clear recommendation. The proposed language fails to give clear guidance as to how "no" votes will be rejected and does not meet the intent of the NERC Board's approval of the SPIG report.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of		

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comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process. With respect to NERC's balloting software and "providing options for voting no with guidance choices for the answer with a comment section on the ballot" - ultimately, NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff are prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question. In the current process, NERC can and does manually correlate comments with ballots (including comments submitted by affiliated entities – NERC must maintain an awareness of which entities are 'affiliated' in order to maintain the Registered ballot Body in accordance with the Rules of Procedure). For this reason, SPM revisions will not contain details about software.		
ISO New England Inc.	No	We have strong concerns with discounting negative votes without comments or the rejection of ballots for unrelated comments. Ultimately an individual has the right to say a standard is not needed and that no amount of tweaking will make it acceptable. The voting section is very confusing regarding abstentions and how these are accounted for in either the quorum or approval calculations. The confusion would be minimized if the current process was not changed. There was intermingling of "calendar days" and "business days" in this section. We believe the ballot body should get 10 business days to vote.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to		

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inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process. The SCPS has an obligation to be responsive to the SPIG recommendations and to maintain the 'status quo' is not responsive nor does it address the concerns with SDTs having the ability to develop quality standards in a timely fashion that achieve industry consensus. The SPCS also believes that the current time requirements associated with the individual steps within the standard development process are necessary to minimize the time required for the development of standards. Extending the ballot window from 10 calendar days to 10 working days would be counter to the SPIG recommendations which are calling for improvements to shorten the process.		
Trans Bay Cable LLC	No	I can't support the voting change even if it may still comply with ANSI standard development requirements. The ANSI process is generally used for "voluntary" standards or industry guidelines such as IEE 693, rather than for mandatory/sanctionable standards, so that going above and beyond the ANSI process to provide a broad unfettered voting pool is appropriate. Requiring "related" comments with a negative vote, but not a positive vote dilutes the voting pool for those that disagree with the proposal. Tasking drafting teams with making this distinction of what is "related" seems problematic at best. In addition, this change could violate the due process mandate in Section 215 of the FPA requires NERC "provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties" Allowing the drafting team to omit any negative vote and comment it deems not "related" does not appear to pass either a "due process" or a "balance of interests" test.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval.		

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Exelon Corporation	No	Exelon supports the EEI comments on Negative Votes and cannot support the current approach. Including all negative votes to achieve quorum but not allowing equal representation in the vote is disingenuous. Negative votes without comment may not provide input to the standard work, but negative votes may or may not be inconsistent with consensus building. The SPM does not address who and how a comment is deemed unrelated to a proposed standard. It's conceivable that broader influences may be driving a vote that may be unrelated to proposed standard language, but equally valid in determining a vote.Also at play is that the current voting system does not allow voters to submit comments with their vote. This is understandable in avoiding duplicative comments between the comment form and the ballot, but at present, votes are not easily aligned with the separately submitted comments forms. An added technical issue is that at present, no comments are allowed in a recirculation ballot. If the SC insists on only counting negative votes with comments, please confirm that that opportunity to comment will be available in the Final Ballot (section 4.14).In addition, please explain the rationale behind removing abstentions from the quorum (section 4.10). Abstentions have a separate meaning to voters. As currently worded, abstentions hold the same presence as non-responses which is contrary to the distinction.While the ultimate goal is to develop and pass Reliability Standards, this approach appears to be an attempt to "stuff the ballot box." This is contrary to representation in the full process. The technical issues are likely to be easily addressed; however, such a restriction on the use of negative votes and abstentions warrants reconsideration and a more full explanation of the management of these votes.

Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval.

The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The

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SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process. With respect to NERC's balloting software and "providing options for voting no with guidance choices for the answer with a comment section on the ballot" - ultimately, NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff are prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question. In the current process, NERC can and does manually correlate comments with ballots (including comments submitted by affiliated entities – NERC must maintain an awareness of which entities are 'affiliated' in order to maintain the Registered ballot Body in accordance with the Rules of Procedure). For this reason, SPM revisions will not contain details about software. The calculation of a quorum has been revised to include abstentions in the same manner as the current SPM.		
Xcel Energy	No	1) We appreciate what was trying to be accomplished with this modification. However, the process to determine if an entity's comment is unrelated seems cumbersome and potentially long, plus there is the possibility that ballot results would not be final for 60+ days. Therefore, we do not see how this change would benefit standard drafting teams or NERC staff. (Nor do we feel it will speed up the process.) The Xcel Energy personnel that participate on standard drafting teams indicated that it is rare to get a truly unrelated comment anyway. So, we recommend that the negative vote be counted in the total approval count, and that the process be removed. We do agree that ballots with no comment at all should not be counted in the ballot pool approval.2) "Consensus vote", under section 1.4, should be modified to match the wording in section 4.10.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The		

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SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process. The calculation of a quorum has been revised to include abstentions in the same manner as the current SPM.		
Western Electricity Coordinating Council	Yes	WECC believes that the proposed revision adequately addresses recommendation 4 provided the intent is to encourage meaningful feedback to the drafting teams. WECC would be opposed to any change in this area that was intended to allow negative votes to be discounted for the sole purpose of advancing a standard by improving the approval percentage.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval.		
SPP Standards Review Group	Yes	We don't take issue with the proposal for handling 'no' votes but would like clarification on one specific item. During discussions on 'no' votes in another arena, a question came up regarding whether a comment accompanying a 'no' vote had to be specifically with the ballot or could it be a reference to a comment from some other entity. For example, if XYZ voted no and referred to a comment submitted by SPP for its justification for that vote, would this be considered a valid 'no' vote?
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process.		

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With respect to NERC's balloting and commenting software - ultimately, NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff are prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question. For this reason, SPM revisions will not contain details about software.		
Oklahoma Gas & Electric	Yes	Assuming there is a mechanism for adding comments when casting the ballot. Previously, comments could be submitted individually using the official commenting process or as a group with those in support of the group comments providing that comment when the ballot is cast. Will this still be a mechanism or will individual comments utilizing the official comment form be required in order for a "negative" ballot to be used in the determinatio of the quorum and in calculating industry consensus? We support being able to provide a comment referencing a group's official comments as a means for casting a "negative" ballot and it being used in the quorum and consensus.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval. The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process. With respect to NERC's balloting and commenting software - ultimately, NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff are prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question. For this reason, SPM		

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revisions will not contain details about software.		
Independent Electricity System Operator	Yes	It appears to be a fair attempt to focus the standard drafting and adoption process
Response: Thank you for your comments. In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval.		
Georgia System Operations	Yes	The revision addresses the SPIG recommendation; however we disagree with the revision and the recommendation for the following reasons:We do not believe that it will improve the Standards Development Process. We believe that the vast majority of "no" votes without comments are expressing fundamental disagreement with the standard. This belief is based on the fact that if an entity has a specific item they would like changed it is to the entity's benefit to make a comment requesting the change, but if the entity disagrees with the need for the standard, there is no benefit to the entity in making a comment. Accordingly many entities that are currently voting "no" without comment will now simply vote "no" and state a philosophical disagreement. Hence there will be no significant change in the process or result.We believe the phrasing of the question reveals a fundamental shortcoming in the proposal which is the assumption that the only valid comments are those that are helpful in modifying the language of the standard to make it acceptable to the commenter. It is perfectly acceptable (and protected by ANSI) for an entity to express fundamental disagreement with the core intent of a standard and base a "no" vote on a philosophical comment to that effect. It is disturbing that the question refers repeatedly to "constructive" comments but never mentions comments expressing philosophical differences with the approach the SDT has taken. We are concerned that there would be a tendency to omit or downplay entities' rights to make such comments in order to improve the likelihood of standards being approved.Restricting a person's right to vote is simply un-American (we cannot speak

Organization	Yes or No	Question 2 Comment
		for our Canadian neighbors, but it is our understanding that it is a fundamental issue there as well). In this country we go to great lengths to ensure that every person's vote is counted. It goes against our instincts to propose eliminating votes on what many will see as a technicality. We feel it will do far more to damage NERC's reputation and create mistrust throughout the industry than it will do to improve the efficiency of the standards development process. Because of the necessary appeals procedures, this proposal will in fact extend the standards development process and make it less efficient.Alternative measures would be more effective at increasing the number of comments than this proposal without the negative side effects. One possible approach would be to modify the on-line forms to encourage comments by enabling users to give input by selecting options (e.g. standard is not clear enough, cost to benefit ratio is too high, do not believe standard will improve reliability, agree with approach but disagree with specific values or thresholds) as well as free-form comments.

Response:

Thank you for your comments. In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count toward achieving a quorum and the calculation of the approval.

The SCPS believes stakeholders that vote 'No' and provide no comment are not supplying helpful guidance to the SDT. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. The SCPS believes that when the entity signifies that they will participate in the standards action ballot (i.e., joins the ballot pool), that entity assumes the responsibilities associated with participation in the standards development process.

With respect to NERC's balloting software and "providing options for voting no with guidance choices for the answer with a comment section on the ballot" - ultimately, NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff are prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question. In the current process, NERC can and does manually

Organization	Yes or No	Question 2 Comment
correlate comments with ballots (including comments submitted by affiliated entities – NERC must maintain an awareness of which entities are 'affiliated' in order to maintain the Registered ballot Body in accordance with the Rules of Procedure). For this reason, SPM revisions will not contain details about software.		
ReliabilityFirst	Yes	ReliabilityFirst notes that the revised SPM does not address how negative ballot cast without comments, or with unrelated comments during the recirculation ballot are to be handled. For example, if a Ballot Pool member changes their vote from Affirmative to Negative during a recirculation ballot, are they required to submit comments along with the vote? Since the recirculation ballot is the final ballot, it would seem that comment would not be required (i.e. regardless of the negative comment, the SDT is not allowed to change the standard). The revised SPM is silent on this issue. I today's environment, comments are not even collected during the recirculation ballot. ReliabilityFirst recommends adding additional language to clarify how a negative ballot cast without comments, or with unrelated comments during the recirculation ballot are to be handled.
Response: NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff are prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question. In the current process, NERC can and does manually correlate comments with ballots (including comments submitted by affiliated entities – NERC must maintain an awareness of which entities are 'affiliated' in order to maintain the Registered ballot Body in accordance with the Rules of Procedure). For this reason, SPM revisions will not contain details about software.		
Bonneville Power Administration	Yes	
National Grid and Niagara Mohawk (A National Grid Company)	Yes	

Organization	Yes or No	Question 2 Comment
Salt River Project	Yes	
City of Austin dba Austin Energy	Yes	
Essential Power, LLC	Yes	
PPL Corporation NERC Registered Affiliated		The PPL Companies appreciate the Standards Committee's efforts to revise the voting process to streamline and reduce cycle time in the voting process. The PPL Companies do have concerns with the "negative comments test" to determine if comments are "related" to the proposal under consideration and question if these modifications will significantly reduce the time needed for the standard development. Even if the proposed process is implemented, the lack of rigorous criteria for deciding whether comments are "unrelated" appears to complicate the review of negative comments. As stated in ANSI Essential Requirements: Due process requirements for American National Standards,Â§2.7 2., "[Standards Developers] shall record and consider . . . negative votes accompanied by comments of a procedural or philosophical nature." (Emphasis added). Assigning the "negative comments test" to the Standard Drafting Team introduces opportunity for bias in that these persons, having considered their product to be ballot-ready, can reasonably be expected to be hoping for a positive outcome. It is unclear to the PPL Companies how the decision will be made to reject unrelated comments. A definitive and transparent process is needed to establish how comments will be evaluated.The requirement that ballot results will not be finalized until all appeals are evaluated and decided appears to add complexity that could delay the development of standards. This would be inconsistent with the stated intent of providing a more rapid development of standards.
Response: In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. No votes with comments of any kind would count		

Organization	Yes or No	Question 2 Comment
toward achieving a quorum and the calculation of the approval.		

3. **As part of Recommendation 4, the SPIG encouraged NERC to require the alignment of standard requirements/measures with Reliability Standard Audit Worksheets (RSAWs). The SPIG also recommended that NERC revise the Essential Elements of the Standards Template to eliminate redundancies.**

   To address these recommendations, the revised Standard Process Manual eliminates measures from the standard template in favor of having drafting teams work with ERO compliance staff to develop more detailed RSAWs in parallel with the standard.

   Does this proposed revision adequately address SPIG Recommendation 4? If not, please explain why and offer an alternative solution for addressing the SPIG's Recommendations with respect to RSAWs and the Essential Elements of the Standards Template.

Summary Consideration:

We appreciate all of the comments provided on the first draft of SPM changes. In analyzing the comments, there was much support for the move of measures to RSAWs. There was also concern expressed about industry involvement and much of the concern seemed to be generated by lack of information provided on the process that would be used to develop the RSAW. While the SPIG recommendation does not specifically suggest removal of the measures from the standard it does *state "Ensure clarity on reliability objectives and compliance obligations.*

i. SDT is responsible for the development of the standard including requirements and measures.

ii. Compliance staff will develop RSAWs (that will be used in the auditing of compliance) in conjunction and coincident with the development of the standard."

Typically RSAWs have been developed by compliance staff after FERC has approved a reliability standard with no involvement of standard drafting teams or industry. Many of the existing measures included in standards today are nothing more than a repeat of the requirement which offers little value to registered entities or compliance auditors. The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. Compliance staff assigned to work with the SDT will be identified at the beginning of each standard project. The SDT has access to the SC to voice concerns that they have with the standard development process which would also include the companion RSAW development process. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW.

There was also some views expressed about who has the final say on the measures and that currently the SDT and industry have the final say. We believe this concern is alleviated by the process envisioned and the fact that the measures are not enforceable. The Commission has acknowledged that it is in NERC's discretion whether to provide Measures for the Requirements of a Reliability Standard. See e.g., Mandatory Reliability Standards for the Bulk-Power System, 118 FERC 61,218 at P 253 (2007)*("The Commission disagrees with commenters that a Reliability Standard cannot reasonably be enforced, or is otherwise not just and reasonable, solely because it does not include Measures and Levels of Non-Compliance. The Commission adopts the position it took in the NOPR that, while Measures and Levels of Non-Compliance provide useful guidance to the industry, compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement given the specific facts and circumstances of its use, ownership or operation of the Bulk-Power System. As we explained in the NOPR, and reiterate here: 'The most critical element of a Reliability Standard is the Requirements."*

There was also some question about the transition to the new process. Some transition has already begun with the development of the RSAWs for PER-005, FAC-003-2 and COM-002-2a. The compliance staff has sought input from the industry and members of the previous drafting team on these new RSAWs. In addition, the SDT for COM-003-1 has been working with Compliance Staff to produce a RSAW for the revised standard. This is in its final stages today and the next posting will include the draft standard and the draft RSAW. The new process would be used to develop RSAWs for standards that are being revised or new standards that are being developed.

Organization	Yes or No	Question 3 Comment
Dominion	No	The question is not aligned with the language of SPIG Recommendation 4. The revisions to the SPM provide little to no mention of the four bullets under SPIG Recommendation 4. Dominion supports the retaining the measures as developed by the drafting team.
Response: Thank you for your comment. While the SPIG recommendation does not specifically suggest removal of the measures from the standard it does *state* ***"Ensure clarity on reliability objectives and compliance obligations.*** ***i. SDT is responsible for the development of the standard including requirements and measures.*** ***ii. Compliance staff will develop RSAWs (that will be used in the auditing of compliance) in conjunction and coincident with the development of the standard."***		

Organization	Yes or No	Question 3 Comment
The SDT and compliance staff will work together to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period and may be balloted with a non-binding poll similar to what is done with the VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW. Other bullets under Recommendation 4 do not require SPM revisions and are being pursued concurrently (reference the CEAP process and the Paragraph 81 Project).		
IRC-SCR	No	We agree that too much time and effort is spent on some of the compliance elements. The proposal appears geared more to taking the industry out of the process rather than saving total work (particularly for changes to the RSAW after the drafting team has been disbanded). We can't see how there is savings of work if a measure is crafted in an RSAW vs. a standard. Perhaps this could be explained better.If NERC moves to RSAWs rather than Measures, NERC needs to use input from the drafting team. The drafting teams also need some mechanism to voice concerns to the Standards Committee if their input is not used. Finally, NERC needs a transition approach to use present work in progress by drafting teams.If measures are retained, they should be included in the standard as opposed to the RSAW. This will support objectivity and is reflective of a consensus position developed in the standards process.
Response: Thank you for your comment. Typically RSAWs have been developed by compliance staff after FERC has approved a reliability standard with no involvement of standard drafting teams or industry. Many of the existing measures included in standards today are nothing more than a repeat of the requirement which offers little value to registered entities or compliance auditors. The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. The SDT has access to the SC to voice concerns that they have with the standard development process which would also include the companion RSAW development process. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The new process may also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the		

Organization	Yes or No	Question 3 Comment
approved reliability standard, the implementation plan and the RSAW. Some transition has already begun with the development of the RSAWs for PER-005, FAC-003-2 and COM-002-2a. The compliance staff has sought input from the industry and members of the previous drafting team on these new RSAWs. The new process would be used to develop RSAWs for standards that are being revised or new standards that are being developed.		
MRO NSRF	No	The NSRF does not agree that the revisions to the SPM address SPIG Recommendation #4 regarding RSAWs. The SPM revisions fail to address the RSAWs altogether including the when and how RSAWs are developed and their review and approval process. A very good RSAW can only be developed upon full approval from the Commission. The Essential Elements of the Standard should include the relationship of RSAWs to the drafted Standard.
Response: Thank you for your comment. While the SPIG recommendation does not specifically suggest removal of the measures from the standard it does *state* ***"Ensure clarity on reliability objectives and compliance obligations.*** ***i. SDT is responsible for the development of the standard including requirements and measures.*** ***ii. Compliance staff will develop RSAWs (that will be used in the auditing of compliance) in conjunction and coincident with the development of the standard."*** We agree that the SPM should address RSAW development; we believe that rather than including the RSAW relationship to the draft standard in the Essential Elements section, it is more appropriate to include language in the section that addresses the Standard Drafting Team responsibility. (Section 3.6) It is not the consensus view that a very good RSAW can only be developed upon full approval of a standard by the Commission. A very good RSAW will be the result of the collaboration of the SDT (subject matter experts) and Compliance Staff. We do agree however that the RSAW may need to be reviewed if the Commission's action on a standard requires substantive change.		
Florida Municipal Power Agency	No	FMPA supports the approach in concept; however, we checked the "No" box because we are concerned with the change of authority concerning who has final say on "Measures". With the new approach, portions of the RSAW will essentially replace the need for Measures in the standard. Currently, the SDT and industry have final say on the Measures. With this approach, Compliance Staff will essentially have final say on the Measures. FMPA understands that certain portions of the RSAW need to remain under the authority of Compliance Staff; however, FMPA believes that the

Organization	Yes or No	Question 3 Comment
		portion of the RSAW that essentially replaces Measures ought to be under the authority of industry through the SDT and balloting.FMPA is also concerned about transition. RSAWs take time to develop; how will the transition from the way we do it now to this new method occur?
Response: Thank you for your comment. While you are correct on the current "final say" on measures being with the SDT and industry through the development and balloting, the measures are not enforceable. The Commission has acknowledged that it is in NERC's discretion whether to provide Measures for the Requirements of a Reliability Standard. See e.g., Mandatory Reliability Standards for the Bulk-Power System, 118 FERC 61,218 at P 253 (2007)***("The Commission disagrees with commenters that a Reliability Standard cannot reasonably be enforced, or is otherwise not just and reasonable, solely because it does not include Measures and Levels of Non-Compliance. The Commission adopts the position it took in the NOPR that, while Measures and Levels of Non-Compliance provide useful guidance to the industry, compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement given the specific facts and circumstances of its use, ownership or operation of the Bulk-Power System. As we explained in the NOPR, and reiterate here: 'The most critical element of a Reliability Standard is the Requirements."***) The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW. Some transition has already begun with the development of the RSAWs for PER-005, FAC-003-2 and COM-002-2a. The compliance staff has sought input from the industry and members of the previous drafting team on these new RSAWs. In addition, the SDT for COM-003-1 has been working with Compliance Staff to produce a RSAW for the revised standard. This is in its final stages today and the next posting will include the draft standard and the draft RSAW. The new process would be used to develop RSAWs for standards that are being revised or new standards that are being developed.		
SERC Planning Standards Subcommittee	No	While RSAWs developed in parallel is a good idea, measures should remain with the standard. Since there is a potential for the measures to modify requirements, they should remain subject to industry approval.
Response: Thank you for your comment. We appreciate your desire to keep the measures in the standard. However, the measures are not		

Organization	Yes or No	Question 3 Comment
enforceable. The Commission has acknowledged that it is in NERC's discretion whether to provide Measures for the Requirements of a Reliability Standard. See e.g., Mandatory Reliability Standards for the Bulk-Power System, 118 FERC 61,218 at P 253 (2007)***("The Commission disagrees with commenters that a Reliability Standard cannot reasonably be enforced, or is otherwise not just and reasonable, solely because it does not include Measures and Levels of Non-Compliance. The Commission adopts the position it took in the NOPR that, while Measures and Levels of Non-Compliance provide useful guidance to the industry, compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement given the specific facts and circumstances of its use, ownership or operation of the Bulk-Power System. As we explained in the NOPR, and reiterate here: 'The most critical element of a Reliability Standard is the Requirements."***) The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW.		
Occidental Energy Ventures Corp. (OEVC) and Electricity Consumers Resource Council (ELCON) together called Industrial Consumers	No	Industrial Consumers agree that that RSAWs should be posted (but not voted) with draft standards for industry review and comment. Industrial Consumers also believe that RSAWs should be developed collaboratively by the SDTs and NERC compliance staff - not by having "drafting teams work with ERO compliance staff." The language in the proposed changes to the SPM does not recognize this nuance and gives too much authority to the compliance staff. It is our understanding that the Measures, which are presently in the Reliability Standards, will transition to the RSAWs. If an entity disagrees with an RSAW, such entity will need to vote "no" for the Standard, as the Measures must be vetted through the process, as they are today. To the extent that posting RSAWs makes them consistent with the applicable Standard, then there should be no need for Compliance Application Notices (CANs) and CANs should then be eliminated under this process.
Response: Thank you for your comment. The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. Compliance staff assigned to work with the SDT will be identified at the beginning of each standard project. We will revise the language in the SPM to reflect that intent. The RSAW will be posted for industry review and comment along with the reliability		

Organization	Yes or No	Question 3 Comment
standard during the final 45 day comment/ballot period. Some transition has already begun with the development of the RSAWs for PER-005, FAC-003-2 and COM-002-2a. The compliance staff has sought input from the industry and members of the previous drafting team on these new RSAWs. In addition, the SDT for COM-003-1 has been working with Compliance Staff to produce a RSAW for the revised standard. This is in its final stages today and the next posting will include the draft standard and the draft RSAW. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW. We agree that with the collaborative development of the RSAW and a well written results-based standard, the need for CANs should be eliminated.		
National Rural Electric Cooperative Association (NRECA)	No	NRECA does not agree that adequate support has been provided for the elimination of Measures and replacing those elements with a vague role for SDTs in the development of RSAWs. It is unclear what the roles are for NERC staff and SDTs as it relates to the development of RSAW language. In addition, without knowing the role for SDTs, we are unsure if this will be a time saving change for the SPM. We request that further details be provided in this area so stakeholders can make an informed decision on this issue.
Response: Thank you for your comment. We recognize the concern expressed about the lack of information provided on the process that would be used to develop the RSAW. The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. Compliance staff assigned to work with the SDT will be identified at the beginning of each standard project. We will revise the language in the SPM to reflect that intent. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW.		
Manitoba Hydro	No	The proposed revisions could potentially address Recommendation 4, but it depends on how the RSAWs will be modified. Also, we are concerned that if the measures become part of the RSAWs they will no longer be subject to industry voting/approval and that the measures listed in the RSAWs will have no formal industry check in place

Organization	Yes or No	Question 3 Comment
		to ensure that they are aligned with the original intent of the requirements.
Response: Thank you for your comment. The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW. If a standard is later revised, the RSAW will also be revised using the same process. Some transition has already begun with the development of the RSAWs for PER-005, FAC-003-2 and COM-002-2a. The compliance staff has sought input from the industry and members of the previous drafting team on these new RSAWs. In addition, the SDT for COM-003-1 has been working with Compliance Staff to produce a RSAW for the revised standard. This is in its final stages today and the next posting will include the draft standard and the draft RSAW.		
Kansas City Power & Light	No	Something that clearly dictates what is required for a demonstration of compliance and the data retention required is an important part of the standards process. This information provides the necessary guidance to enable those with the task to demonstrate compliance the information necessary to do so and for those with the task to determine compliance the guidance to do so. The white paper suggests this should be accomplished in the development of the RSAW in parallel with the standard development in replacement of the current measures in the standards. It is immaterial whether a description of what is needed to demonstrate compliance and data retention is in the standard or the RSAW as long as it is part of the standards process for industry approval and sufficiently described. The proposed Standard Process Manual does not sufficiently describe the framework that the RSAW should be nor does the proposed Standard Process Manual stipulate the RSAW should be included in standards process.
Response: Thank you for your comment. We agree that it does not really matter where the measure resides as long as it is clear and reflects the intent of the SDT. The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The		

Organization	Yes or No	Question 3 Comment
new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW. If a standard is later revised, the RSAW will also be revised using the same process. Details about the framework for RSAW development are not appropriate for inclusion in the SPM. However, sections 3 and 4 of the SPM have been revised to clarify the partnership of the SDT and compliance staff in the development of the RSAW. The Standards Committee has many procedure documents that reflect processes that are used in the development of standards. It is currently envisioned that the SC and Compliance staff will develop a process document that will reside on the Standards Webpage.		
Georgia System Operations	No	GSOC is ambivalent regarding the elimination of Measures. To us the key is not where information is found, but that: 1) the information is well documented and useful to entities and 2) that there is a clear understanding of its purpose and limitations. The proposed changes to the SPM introduce references to RSAWs but do not adequately state the purpose and limitations of RSAWs. It needs to be made very clear that the requirements will remain the only enforceable language and that the intended meaning must be conveyed by the requirements themselves without reference to the RSAW. We are concerned that we may merely be trading poorly written measures for poorly written RSAWs. Wherever this information is located it should provide examples of the type of information an auditor might expect to see as proof of compliance while making clear that it is not a limitation on what evidence can be used.Wherever the information is located, we agree with specifying situations where an attestation would be appropriate, but this should not preclude submitting an attestation in a situation where it is not specified because it is impossible to foresee every scenario. We disagree with specifying what non-compliance would look like; we believe that is beyond the scope of an RSAW. It is the entity's responsibility to show compliance to the standard. Non-compliance should simply be the failure to show compliance.There should be a process for later changes to the RSAW without SDT input (by NERC compliance staff) with some level of review (SC approval perhaps) and an opportunity for industry comment.
Response: Thank you for your comment. We agree that it does not really matter where the measure resides as long as it is clear and		

Organization	Yes or No	Question 3 Comment
reflects the intent of the SDT and provides useful information. The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW. If a standard is later revised, the RSAW will also be revised using the same process.		
Public Service Enterprise Group	No	Measures" were previously approved by the RBB, the NERC board, and regulatory authorities. We do not object to measures being incorporated into RSAWS provided that the this SPM draft is revised to give the RBB the opportunity to provide comments on the RSAWs (a) in parallel with the standard development and (b) at any time RSAWs changes are proposed.
Response: Thank you for your comment. The RBB will have the opportunity to provide comments on the RSAWs. The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW. If a standard is later revised, the RSAW will also be revised using the same process.		
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency (IMEA) supports comments submitted by Florida Municipal Power Agency.
Response: Thank you for your comment. While you are correct on the current "final say" on measures being with the SDT and industry through the development and balloting, the measures are not enforceable. The Commission has acknowledged that it is in NERC's discretion whether to provide Measures for the Requirements of a Reliability Standard. See e.g., Mandatory Reliability Standards for the Bulk-Power System, 118 FERC 61,218 at P 253 (2007)***("The Commission disagrees with commenters that a Reliability Standard cannot reasonably be enforced, or is otherwise not just and reasonable, solely because it does not include Measures and Levels of Non-Compliance. The Commission adopts the position it took in the NOPR that, while Measures and Levels***		

Organization	Yes or No	Question 3 Comment
of Non-Compliance provide useful guidance to the industry, compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement given the specific facts and circumstances of its use, ownership or operation of the Bulk-Power System. As we explained in the NOPR, and reiterate here: 'The most critical element of a Reliability Standard is the Requirements.") The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW. Some transition has already begun with the development of the RSAWs for PER-005, FAC-003-2 and COM-002-2a. The compliance staff has sought input from the industry and members of the previous drafting team on these new RSAWs. In addition, the SDT for COM-003-1 has been working with Compliance Staff to produce a RSAW for the revised standard. This is in its final stages today and the next posting will include the draft standard and the draft RSAW. The new process would be used to develop RSAWs for standards that are being revised or new standards that are being developed.		
FirstEnergy Corp	No	1. Section 3.5 indicates NERC Staff will develop the RSAWs with assistance from Drafting Teams "as needed". We are not clear as to when and how these RSAWs are developed. FE believes this activity would be most efficient and effective in parallel with the development of the requirements of the standard. The SDT should always be involved and not "as needed" and the RSAWs should be part of the standard document with a non-binding poll on the RSAWs. We suggest some parameters and discussion be developed in the process as to how RSAWs are developed and if a non-binding poll similar to VRF/VSL will be used.2. FE would like to point out our support of the information in section 2 that clearly specifies the enforceable elements of a standard that are subject to sanctions. We appreciate this additional clarity.
Response: Thank you for your comment. We recognize the concern expressed about the lack of information provided on the process that would be used to develop the RSAW. The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. Compliance staff assigned to work with the SDT will be identified at the beginning of each standard project. Sections 3 and 4 of the SPM have been revised to clarify that the SDT and compliance staff will work together to develop the RSAW. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The		

Organization	Yes or No	Question 3 Comment
new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW.		
Ameren	No	(1) We believe that the SDT to develop the RSAW is a step in the right direction, but we are not sure whether or not the RSAW would subsequently go through industry review and the ballot process. If not, we recommend that everything that is involved with a standard and what is needed to comply with a standard's requirements (that is, Measures) should be encapsulated within the standard document itself. If the RSAWs are developed at the same time as the standards, we recommend keeping the RSAW language in line with the standards requirements and measures, but the measures need to remain within the standards. Any potential for measures to modify standard requirements should be addressed in the standards development process, where there is industry review and the commenting process is in place. (2) Will the entire SDT be involved in the RSAW development or will this be delegated to a sub group?
Response: Thank you for your comment. We recognize the concern expressed about the lack of information provided on the process that would be used to develop the RSAW. The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. Compliance staff assigned to work with the SDT will be identified at the beginning of each standard project. It will be up to each combined group how they want to go about developing the RSAW, i.e. subgroup or not, as with other elements of the standard currently, but in the end, the RSAW that is posted for review and comment will be the consensus of the entire team. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. If the measures in the RSAWs have be written such that industry believes that they modify the requirement, the industry should comment so that the SDT and compliance can review and correct any problems before the RSAW is finalized. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW.		

Organization	Yes or No	Question 3 Comment
Indiana Municipal Power Agency	No	Indiana Municipal Power Agency supports the comments submitted by Florida Municipal Power Agency.
Response: Thank you for your comment. While you are correct on the current "final say" on measures being with the SDT and industry through the development and balloting, the measures are not enforceable. The Commission has acknowledged that it is in NERC's discretion whether to provide Measures for the Requirements of a Reliability Standard. See e.g., Mandatory Reliability Standards for the Bulk-Power System, 118 FERC 61,218 at P 253 (2007)***("The Commission disagrees with commenters that a Reliability Standard cannot reasonably be enforced, or is otherwise not just and reasonable, solely because it does not include Measures and Levels of Non-Compliance. The Commission adopts the position it took in the NOPR that, while Measures and Levels of Non-Compliance provide useful guidance to the industry, compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement given the specific facts and circumstances of its use, ownership or operation of the Bulk-Power System. As we explained in the NOPR, and reiterate here: 'The most critical element of a Reliability Standard is the Requirements."***) The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW. Some transition has already begun with the development of the RSAWs for PER-005, FAC-003-2 and COM-002-2a. The compliance staff has sought input from the industry and members of the previous drafting team on these new RSAWs. In addition, the SDT for COM-003-1 has been working with Compliance Staff to produce a RSAW for the revised standard. This is in its final stages today and the next posting will include the draft standard and the draft RSAW. The new process would be used to develop RSAWs for standards that are being revised or new standards that are being developed.		
American Transmission Company	No	ATC does not agree that the revisions to the SPM address SPIG Recommendation #4 regarding RSAWs. The SPM revisions fail to address the RSAWs altogether including the when and how RSAWs are developed and their review and approval process.Furthermore, the Essential Elements of the Standard should include the relationship of RSAWs to the drafted Standard.
Response: Thank you for your comment. While the SPIG recommendation does not specifically suggest removal of the measures from the standard it does *state* ***"Ensure clarity on reliability objectives and compliance obligations.***		

Organization	Yes or No	Question 3 Comment
		i. SDT is responsible for the development of the standard including requirements and measures. ii. Compliance staff will develop RSAWs (that will be used in the auditing of compliance) in conjunction and coincident with the development of the standard." We agree that the SPM should address RSAW development; we believe that rather than including the RSAW relationship to the draft standard in the Essential Elements section, it is more appropriate to include language in the section that addresses the Standard Drafting Team responsibility. (Section 3.6) The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW.
Exelon Corporation	No	The role of measures and RSAWs going forward is very confusing. The language in the proposed SPM divorces the compliance component from the standard development; however, it's not clear how NERC will ensure that the relevant context and intent of the standard is reflected in the compliance components. Furthermore, removal of the measures takes away a stable piece of the standard that enables entities to build a compliance program based on predictable measures. Compliance components must be developed in tandem with the standard language to capture context and intent of the standard and to create a stable compliance measure. There is value in developing an RSAW within the standard development process if it achieves creating one RSAW to be used by all regions and does not change over time. Many questions remain about the concept of RSAW development in parallel with standard development - will they be BOT approved, will they change, who can change them, etc. Until it is clear how RSAW development will transpire, the measures component should not be dropped from the standard development. This is a matter of NERC creating credible compliance elements that respect the standard language as written and intended and that are stable over time.
Response: Thank you for your comment. We recognize the concern expressed about the lack of information provided on the process that would be used to develop the RSAW. The new process will have the SDT and compliance staff working collaboratively to		

Organization	Yes or No	Question 3 Comment
develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. Compliance staff assigned to work with the SDT will be identified at the beginning of each standard project. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. If the measures in the RSAWs have been written such that industry believes that they modify the requirement, the industry should comment so that the SDT and compliance can review and correct any problems before the RSAW is finalized. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW. If a standard is later revised, the RSAW will also be revised using the same process.		
Xcel Energy	No	1) Evidence Retention is being removed as an Element of a Reliability Standard. We assume this will be moved into the RSAW, along with measures. Since there is mention of the drafting team assisting in the development of RSAWs, it would be helpful to provide a short list of items that shall be included in the RSAW, such as evidence retention requirements.2) The last sentence of the first paragraph under section 3.5 needs modification. Currently, it states that the drafting team will assist in the RSAW development "as needed". We disagree that the drafting team's participation be at the discretion of NERC staff. Instead, it should be clarified that the drafting team will actively participate in the development of the RSAW. Furthermore, since they own the technical content in the standard, their perspectives on the technical aspects of the RSAW should also be given significant consideration.
Response: Thank you for your comment. Yes, evidence retention will become part of the RSAW. It is not appropriate for the SPM to include details about the framework for RSAW development. Language will be included in the next revision to reflect the partnership of the SDT and compliance staff in the development of the RSAW. The Standards Committee has many procedure documents that reflect processes that are used in the development of standards. It is currently envisioned that the SC and Compliance staff will develop a process document that will reside on the Standards Webpage. The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. Compliance staff assigned to work with the SDT will be identified at the beginning of each standard project. The language in the SPM will be revised to reflect that intent and clarify that it is not “as needed”. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The new process		

Organization	Yes or No	Question 3 Comment
will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW.		
ACES Power Marketing Standards Collaborators	Yes	We do not object to this change, but ultimately, we believe that standards should be written clearly enough that neither measures nor RSAWs are even needed. If they truly are needed and must be used, then we also would like to emphasize the need to ensure that RSAWs provide real guidance on what compliance and non-compliance looks like. If they become like the measures and just repeat the requirements, they will not be effective. Some current RSAWS fit this category and offer little guidance because they just repeat what is in the requirements. We would also like to express the concern that removing the measures in favor of RSAWs could potentially make the guidance provided in them less accessible to auditors and also make them less likely to consider it good guidance on the standard. We suggest providing a link in the standard to the RSAWs (perhaps where the measures used to be), making the guidance more accessible. In fact, all guidance that NERC would like entities and auditors to use for compliance should be linked from the standard.
Response: Thank you for your comment and support. Typically RSAWs have been developed by compliance staff after FERC has approved a reliability standard with no involvement of standard drafting teams or industry. We agree that many of the existing measures included in standards today are nothing more than a repeat of the requirement which offers little value to registered entities or compliance auditors. The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. Some transition has already begun with the development of the RSAWs for PER-005, FAC-003-2 and COM-002-2a. The compliance staff has sought input from the industry and members of the previous drafting team on these new RSAWs. In addition, the SDT for COM-003-1 has been working with Compliance Staff to produce a RSAW for the revised standard. This is in its final stages today and the next posting will include the draft standard and the draft RSAW. The COM-003 SDT has reported that the collaborative effort in development of the RSAW so far has helped them develop more clear and precise requirements. NERC is reviewing and updating it tools and processes and consideration of links will be part of that process.		

Organization	Yes or No	Question 3 Comment
Hydro One	Yes	We request that RSAWs are subject to the same Quality Review that is currently used for Standards.
Response: Thank you for your comment and support. We believe that it is more important that the RSAW be carefully reviewed by industry during the comment period.		
AECI and the G&T members Central Electric Power Cooperative, KAMO Power Cooperative, M&A Electric Power Cooperative, Northeast Electric Power Cooperative, NW Electric Power Cooperative, and ShoMe Power Electric Cooperative	Yes	AECI agrees with the concept in theory. What that means is that some measure to a requirement needs to be available prior to balloting. Therefore if the RSAW is available to review prior to balloting on the standard then we support the proposed revision. However, if the RSAW is not available prior to balloting, then the measures need to stay within the standard. AECI assumes that the RSAWs would go out for comment and non-binding ballots.
Response: Thank you for your comment and support. The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. If the measures in the RSAWs have be written such that industry believes that they modify the requirement, the industry should comment so that the SDT and compliance can review and correct any problems before the RSAW is finalized. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW. If a standard is later revised, the RSAW will also be revised using the same process.		
SPP Standards Review Group	Yes	We like the suggestion for using the SDT to develop RSAWs. However, there is an apparent lack of consistency between the revised SPM and the whitepaper. On page 10, the last sentence in the first paragraph of Section 3.5 indicates that NERC staff will determine whether to use the SDT to assist with the RSAW development. Yet on page 8 of the whitepaper, the last paragraph under Recommendations more strongly

Organization	Yes or No	Question 3 Comment
		suggests that SDTs will be used in the development of RSAWs. We prefer the later. We also suggest that requirements be written with sufficient specificity such that determining compliance would not have to rely heavily on the RSAWs.
Response: Thank you for your comment and support. The new process will have the SDT and compliance staff working collaboratively to develop the RSAW at the same time the standard is being developed to ensure the intent of the SDT is accurately reflected in the RSAW. Compliance staff assigned to work with the SDT will be identified at the beginning of each standard project. Section 3.5 of the SPM has been revised to clarify this relationship. The RSAW will be posted for industry review and comment along with the reliability standard during the final 45 day comment/ballot period. The new process will also include a non-binding poll of the ballot pool to help gauge industry support of the RSAW similar to what is done for VRFs and VSLs today. The final RSAW will be presented to the BOT for information as part of the package that includes the approved reliability standard, the implementation plan and the RSAW.		
Bonneville Power Administration	Yes	BPA is in support of the drafting team assisting with the creation of the RSAW to further clarify the intent of the standard throughout the industry's implementation and compliance monitoring.
Response: Thank you for your comment and support.		
National Grid and Niagara Mohawk (A National Grid Company)	Yes	Because measures are not an enforceable aspect of the standard, National Grid supports their removal from the standard. Additionally, National Grid views RSAWs as an effective tool for maintaining auditable compliance and for facilitating the audit process. It makes sense for the RSAWs to be developed in conjunction with the standard to ensure that RSAWs truly track the actual requirements of a standard without adding to or changing them. National Grid cautions against attempting to include examples, factors, specific suggestions for meeting compliance etc. in RSAWs because these types of elements can trend toward changing the actual requirements of a standard or suggesting to auditors a more limited scope of enforcement than the

Organization	Yes or No	Question 3 Comment
		language of a standard permits. The lessons learned in attempting to develop VSLs should inform the RSAW drafting process - i.e. it is impossible to preemptively determine all possible methods of compliance, and attempting to develop examples or factors that are not expressly set forth in the actual requirements can lead to overly restrictive enforcement practices during and audit. The requirements of a standard should be clear enough to permit for compliance, even if the requirements allow for multiple methods to achieve compliance. The RSAWs should simply track and reflect the actual requirements of a standard , and drafting the RSAW in conjunction with the standard should better ensure this outcome. National Grid agrees that RSAWs should not be submitted to FERC for approval along with the standard.
Response: Thank you for your comment and support.		
Independent Electricity System Operator	Yes	As long as measures or similar guidance on how compliance will be assessed is provided, we are indifferent as to where that information is included.
Response: Thank you for your comment and support.		
NextEra Energy Inc	Yes	NextEra agrees with moving the measures/examples of evidence to meet compliance to the RSAWs.
Response: Thank you for your comment and support.		
Duke Energy	Yes	Duke Energy supports the ongoing efforts to revise the RSAW content and process, utilizing the expertise of the Standard Drafting Teams and the industry, providing transparency that should result in clearer communication of auditing intent and

Organization	Yes or No	Question 3 Comment
		enhanced consistency.
Response: Thank you for your comment and support.		
Northeast Power Coordinating Council	Yes	
Western Electricity Coordinating Council	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
Liberty Electric Power	Yes	
Oklahoma Gas & Electric	Yes	
Pepco Holdings Inc.	Yes	
Flathead Electric Cooperative, Inc.	Yes	
City of Austin dba Austin Energy	Yes	
ReliabilityFirst	Yes	
ISO New England Inc.	Yes	

Organization	Yes or No	Question 3 Comment
Trans Bay Cable LLC	Yes	
Essential Power, LLC	Yes	
PPL Corporation NERC Registered Affiliated		The PPL Companies agree with the changes made to Section 3. Section 3.0 states: "The only mandatory and enforceable components of a Reliability Standard are the: (1) applicability, (2) Requirements, and the (3) effective dates. The additional components are included in the Reliability Standard for informational purposes, to establish the relevant scope and technical paradigm, and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement".This revision to the Standard Process Manual constitutes a global change which should eliminate CANs. From this point forward, the only guidance provided on Reliability Standards will be contained in the standards. If additional guidance is needed, the industry shall utilize the Interpretation process as defined in this Manual.The PPL Companies support creating the RSAWs in parallel with the standards. The provisions to allow for quality reviews to be conducted in parallel with standard development should be beneficial. Proposed changes to RSAWs should be required to go back to the Standards Development Team for approval to ensure that the changes are consistent with the intent of the SDT.
Response: Thank you for your comment.		

4. **As stated in Question 3, as part of Recommendation 4, the SPIG encouraged NERC to revise the Essential Elements of the Standards Template to eliminate redundancies, using Violation Severity Levels (VSLs) as an example.**

   To address this Recommendation, the revised Standard Process Manual eliminates VRFs and VSLs from the standard template in favor of a Sanction Table Reference (Results-Based Requirement Category Reference) to conserve drafting team and stakeholder resources and ensure consistency in the application of sanctions.

   Does this proposed revision adequately address SPIG Recommendation 4? If not, please explain why and offer an alternative solution to revise the Essential Elements of the Standards Template to eliminate redundancies such as VSLs.

Summary Consideration: The Standards Committee Process Subcommittee's (SCPS) goal with the proposed revision to the Standards Process Manual (SPM) eliminating the Violation Risk Factors (VRF) and the Violation Severity Levels (VSL) would address several issues identified in the SPIG (Standards Process Improvement Group**)** Recommendations:

1. *SPIG Recommendation 4 Standards Product* speaks to how standards will be developed and areas where the quality of standards can be improved. Specifically, the recommendations identify the VSL, within the Essential Elements of a Reliability Standard, as a potential candidate for revision. Recommendation 4 also encouraged the use of the Results-Based Standard (RBS) philosophy.

2. *SPIG Recommendation 5 Standards Development Process and Resources* identifies a need to shorten the ERO Standard Development Process and it is the opinion of the SCPS that the development of VRFs and VSLs establishes a significant burden on the Standard Drafting Team (SDT), which in turn lengthens the standard development process.

Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM.

The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects, and will consider suggestions provided in the comments below as part of that consideration. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders)

to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.

Organization	Yes or No	Question 4 Comment
Dominion	No	SPIG Recommendation 4 does not directly discuss revising the Essential Elements of Standards Template to eliminate redundancies such as VSLs. The topic is however discussed in the document titled: Standard Processes Manual Revisions: SCPS White Papers for Background Information.

Response: The SCPS is acting in good to faith to address the SPIG recommendations and respectfully disagrees with the commenter in that the SPIG Recommendation (4) states the following:

The Board is encouraged to require that the standards development process address:

- The use of RBS;
- Cost effectiveness of standards and standards development;
- Alignment of standards requirements/measures with Reliability Standards Audit Worksheets (RSAWs); and
- The retirement of standards that are no longer needed to meet an adequate level of reliability.

The SPIG report further identifies areas where the overall recommendation is proposed to be applied. These details include the following:

- Revise Essential Elements of the Standards Template to eliminate redundancies such as Violation Severity Levels (VSLs).

Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM.

The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best

Organization	Yes or No	Question 4 Comment
manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Northeast Power Coordinating Council	No	The title of the tables should be changed to 'Operations' Sanctions Table Guidelines, 'Cyber Security' Sanctions Table Guidelines, and 'Planning' Sanctions Table Guidelines. Are these three tables intended to encompass all standards?
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
IRC-SCR	No	We agree there is much wasted effort with regard to VRFs and VSLs. But it appears the proposal is to take one confusing process and replace it with another confusing process that has less industry input. The approach needs to be simplified such that it can be explained on a single page each for VRFs and VSLs. We also have concerns with the proposed sanctions tables that are associated with this proposal. For each category, the proposed sanction should expand from zero to the maximum determined by the risk-outcome combination. To do otherwise complicates the FFT and spreadsheet NOP process (it requires additional documentation to prove why the sanction is less than that allowed by the table).
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-		

Organization	Yes or No	Question 4 Comment
binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Hydro One	No	The title of the tables should be changed to 'Operations' Sanctions Table Guidelines, 'Cyber Security' Sanctions Table Guidelines, and 'Planning' Sanctions Table Guidelines. Are these three tables intended to encompass all standards? What about FAC, MOD, PRC, etc. standards?
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Western Electricity Coordinating Council	No	WECC appreciates the opportunity to comment on the NERC Standards Committee Process Subcommittee (SCPS) Proposal related to the elimination of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs). From a Standards Development perspective, WECC agrees that the proposed revision adequately addresses SPIG Recommendation 4. The concept of a predefined set of Sanctions Tables, one for Operations Requirements, one for Planning Requirements, and one for Cyber Security

Organization	Yes or No	Question 4 Comment
		Requirements, with each including four violation levels for Performance-based, Risk-based, and Capability-based requirements, would greatly reduce the burden on and the time required of the drafting teams in developing the individual VSLs for each requirement of a standard. The proposed revision would also force the drafting teams to consider the language and content of each requirement helping ensure a results-based requirement that was Performance-based, Risk-based, or Capability-based was drafted. It would also greatly reduce the time expended by the industry in reviewing and commenting on VSLs during the drafting period. In addition, it would do away with the time and effort required to revise VSLs during drafting if the requirements had to be revised based on stakeholder feedback. All of these are positives and have the potential to greatly reduce the amount of time it takes to develop a new or revised reliability standard.However, form an enforcement perspective WECC has concerns. WECC Enforcement staff understands the value in reducing the burden imposed on Standards Drafting Teams; however from an enforcement perspective, WECC Enforcement staff believes the proposed Sanction Table and accompanying procedural changes create unnecessary challenges with enforcing Reliability Standard Violations. The proposed Sanction Table is a significant change in Compliance Enforcement operations and may require considerable procedural, process, and personnel staffing alterations. Therefore, WECC provides the comments below in order to specify a number of concerns, from an enforcement perspective, with the SCPS Proposal and to propose alternative solutions to achieve a desirable outcome. WECC Enforcement staff coordinated the development of these comments with the Texas Reliability Entity (TRE) and WECC understands that TRE supports the position reflected by these comments, but we do not speak for TRE.From an enforcement perspective, WECC has the following concerns:1.The language associated with the proposed levels in the Sanction Table is ambiguous, broad, and imprecise. Furthermore, the thresholds to get to Level 3 and Level 4 are unreasonably high. The increased hurdle to reach such upper levels in combination with the periphrastic language supporting each proposed level creates unnecessary challenges when implementing the SCPS Proposal. The SCPS Proposal is a move to

Organization	Yes or No	Question 4 Comment
		more ambiguous, broad, and imprecise language than that in existing VSLs. Such ambiguous, broad, and imprecise language denies the regulated industry as well as WECC Enforcement staff clear and concise direction in the enforcement of the NERC Reliability Standards. 2.The Sanction Table will lead to inconsistent implementation and delay violation processing. Given the ambiguity described in (1), inconsistency in penalty assessments will likely increase throughout all Regional Entities. Similarly, the proposal will provide challenges when comparing the body of FERC-approved violations (and work-in-progress) with future violations enforced according to the proposed Sanction Table. There is nothing in the SCPS proposal regarding how Regional Entities, NERC, or FERC will ensure transparent or consistent outcomes. Violation severity levels (or their replacements) should ensure uniformity and consistency among all Standards in the determination of penalties.3.The SCPS proposal overstates problems associated with enforcing violations using the active VSLs. Currently, there are a few problems with specific VSLs; there is not a problem with all VSLs. WECC Enforcement sees an opportunity to fix some VSLs, e.g., there is an opportunity to provide additional granularity given the limited levels associated with a subset of Reliability Standards, including, for example, the CIP Standards. 4.The SCPS proposal resembles a one-size-fits-all solution to a problem that requires nuance and careful, deliberate application. Every enforceable violation presents with a unique fact pattern. The proposal takes a mechanical, simplistic approach to risk. Any proposal in this dynamic NERC Reliability Standard regulatory environment that attempts to use such an approach requires careful examination prior to implementation. 5.This is a significant change for Compliance and Enforcement. If a change of this magnitude is made, WECC Enforcement recommends having more discussion and exploring the alternatives, some of which are proposed below, before such a significant process change is implemented. WECC Enforcement Staff provides the following as possible alternative solutions1.Complement and Supplement Existing ProcessWECC Enforcement staff does not see major problems with the VSLs, VRFs, or the existing Base Penalty Table. WECC Enforcement staff does, however, see a problem with a few specific VSLs that could be fixed relatively quickly. In this light,

Organization	Yes or No	Question 4 Comment
		there is value in maintaining the status quo with consideration or emphasis given to only a small subset of VSLs or VRFs. Therefore, WECC Enforcement staff proposes maintaining the status quo be considered an effective option. However, WECC Enforcement staff further proposes that Regional Enforcement personnel could provide recommendations to the drafting teams where Enforcement has already identified problems with existing VSLs. This will reduce any undue burden on the Standards Drafting Teams while also gaining the benefits that come from working within an existing, known, process. 2.Develop Expedited Process WECC Enforcement staff appreciates the Standards Drafting Teams concerns that they are spending entirely too much time drafting VRFs and VSLs. To address this concern, WECC Enforcement staff proposes that the Regional Enforcement Staffs, particularly the Enforcement Sanction and Mitigation Working Group (ESMWG), provide recommendations to the Standards Drafting Teams to improve the VRFs and VSLs. Further, the ESMWG could also review proposed VRFs and VSLs, which could streamline the creation of new VRFs and VSLs. The Commission previously directed NERC to develop VSLs "either through the Reliability Standards development process or through another expedited process" (emphasis added). In that context, there is an opportunity for currently existing working groups, e.g., the ESMWG, to provide for the other "expedited process" that the Commission may desire. At present the ESMWG is comprised of NERC and Regional Enforcement managers and leaders. The ESMWG representatives are uniquely positioned to take on this role. Specifically, the ESMWG representatives ultimately implement, enforce, and defend VRFs and VSLs in all enforcement actions. In the Western Interconnection, WECC Enforcement has resolved nearly 2000 violations with FERC. In each case, WECC Enforcement reviewed the violation facts and circumstances and applied a VSL and VRF in each applicable case. As stated in (1), WECC Enforcement staff has determined a few specific VSLs could be fixed relatively quickly. WECC Enforcement staff made this determination based on their experience resolving violations with Registered Entities, NERC, and FERC. The approach also ensures some level of continuity is maintained throughout the drafting or revision processes, as Regional Enforcement Departments are fully

Organization	Yes or No	Question 4 Comment
		staffed with full-time, long-standing employees. Thus, while new Standards Drafting Teams may always be necessary, there would be a reduction in the development or re-learning process associated with each team as such teams can rely on a stable knowledge base (i.e., Regional Enforcement personnel). 3.Continue Existing Work in this AreaWECC Enforcement staff notes that significant work has taken place in the continued development of streamlined methods for VSL drafting since the Standards Drafting Teams first identified the burden. WECC Enforcement staff believes that the enforcement staffs of each of the eight Regional Entities agree that the previously proposed "pro forma" VSL approach is not a workable solution. WECC Enforcement staff also recognizes furtherance of related work on this project may achieve the desired results of the SCPS Proposal (i.e., eliminate the burden associated with VRF and VSL drafting). For example, following the failure of the pro forma VSL proposal, WECC Enforcement staff understood the next project to include template-based VSLs with associated fill-in-the-blank verbiage. Furtherance of template-based VSLs that allow for the unique nature of specific requirements is likely to lead to consistent VSLs and a reduced drafting and resource burden on the Standards Drafting Teams, with minimal noticeable change in processes or compliance approach.In conclusion, WECC Enforcement staff is supportive of providing relief to Standards Drafting Teams, however we suggest NERC, Regional Entities, and the regulated industry ensure a successful transition to such a drastic change, rather than be forced into a tight deadline. Given the concerns outlined above, if NERC and industry adopt and move to implement the SCPS Proposal, WECC Enforcement staff requests that Regional Enforcement personnel take ownership of the proposed Sanction Table and work in concert with NERC Enforcement personnel to craft fair and reasonable language in support of the respective Sanction Table levels.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM.		

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The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
MRO NSRF	No	SPIG Recommendation #4 regarding the example of eliminating the VSLs did not imply they should be replaced by Sanction Tables. The recommendation was a temporary solution on the redundancies. The VSLs should remain until the Sanctions Tables are vetted properly through the proper channels, with NERC Compliance and Stakeholders.The NSRF supports the ultimate removal of the VRFs and VSLs from all Standards in the future once the proposed Sanction Tables are vetted and approved through all required channels.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Edison Electric Institute	No	EEI understands that the proposal framed in the NERC process subcommittee 'white paper' and the proposed draft process manual to be that VRFs and VSLs would no longer be defined as 'essential elements' of a standard, and would no longer be attached to projects with non-binding polls, thus relieving drafting teams of a certain

Organization	Yes or No	Question 4 Comment
		task. In addition, a 'sanctions table' has been proposed as a replacement for the existing base sanctions table contained in the Compliance Monitoring and Enforcement Program (CMEP) manual.SPIG recommended the 'elimination of redundancies such as VSLs.' On the surface, the draft proposed process changes would seem to agree with the underlying process efficiency objective. However, the proposal is confusing for several reasons. First, the white paper simply does not state that VSLs and VRFs will no longer be developed, only suggesting that they will not be developed as part of a drafting team project scope. We may misunderstand the discussion paper, however, we see no alternative process proposal for the development of VSLs and VRFs, and it is important to have a clearer understanding of where and how these variables will be defined.Second, SPIG did not recommend the development of a sanctions table. While we understand that there have been informal discussions on developing such a table, the addition of this material to the SPIG project does not fit with our sense of 'eliminating redundancies.' In addition, the white paper seems to conflate the VSL/VRF process issue with the development of the sanctions table. Certainly, SPIG did not recommend the development of a sanctions table. Third, stakeholders have not actively participated in the setting of enforcement policies and practices, having developed an understanding that NERC did not want to cultivate a perception that stakeholders had an undue influence over such practices. CMEP and the sanctions guidelines were developed with very little stakeholder involvement. VRFs, VSLs, the sanctions guidelines, and their application by NERC and the regions is not well understood. Also, we understand that some standards drafting teams have become very apprehensive about compliance and enforcement matters, becoming worried over how various language might be interpreted by compliance and enforcement. If now there is interest in having a more comprehensive discussion on the overall structure of compliance and enforcement as set forth in CMEP, including various enforcement strategic policies and practices, EEI welcomes that discussion. The nature of enforcement as a tool for properly aligning reliability risks with performance, and creating a structure of strong incentives for avoiding poor performance via enforcement, is a long overdue

Organization	Yes or No	Question 4 Comment
		discussion.Alternatively, if the current proposed approach continues to be included in the SPIG implementation 'package,' EEI notes that the proposed sanctions table contains several ambiguous characterizations such as 'could adversely impact reliability,' which invites potential endless debate if and when such a table were ever to be implemented. Similarly, in the cybersecurity section of the table, the term 'other' is undefined and potentially unbounded. Instead of much needed efficiency and cost savings in compliance and enforcement, implementation of this terminology invites the opposite, that is, endless arguments over whether a particular violation or set of violations "could" have imposed systemic reliability risk. At the very least, the sanctions table needs much further analysis and refinement and should therefore be removed from consideration in the SPIG-related matters. Also, the process for developing VRFs and VSLs needs to be described since it is unclear whether or how these will continue to be developed.In addition, proposed Section 3.9 of the process manual is unnecessary since the role of the Compliance and Certification Committee (CCC) is already defined elsewhere the Rules of Procedure and its own committee charter. The CCC charter also appears to be broadly defined to enable the committee to comment on the enforceability of proposed standards. Committee charters should be complete and self-contained, and not scattered throughout the NERC library of governance and process documents.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		

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Occidental Energy Ventures Corp. (OEVC) and Electricity Consumers Resource Council (ELCON) together called Industrial Consumers	No	Industrial Consumers agree that VRFs and VSLs should be eliminated, but only over the longer term. We all agree that the crafting of risk factors and severity levels under the present process is cumbersome and time consuming. However, this is a reflection of the complexity of equating reliability activities across a wide range of process, planning, and operational functions. In addition, continual refinements have been made over the five years that violations of the Reliability Standards have been subject to penalties - resulting in a level of consistency that is understood by all involved. Further, Industrial Consumers commend the SCPS for its work in developing the "Sanctions Table." The concept appears to have validity. However, it is far from a proven concept. For example, the criteria are high-level and could leave too much discretion to NERC to determine the basis and size of the penalties. It seems that a smaller step should be taken first to establish a level of comfort with the industry - perhaps a limited field trial of the Sanctions Table process. Thus, Industrial Consumers strongly recommend that the SPM not include any mention to the "Sanctions Table."
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
National Rural Electric Cooperative Association	No	After reviewing the draft SPM, NRECA still has questions regarding the elimination of VSLs/VRFs and effectively replacing them with Type of Requirement and Level 1 through 4 violation criteria. How is the proposed Sanctions Table qualitatively

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(NRECA)		different from the current Base Penalty Amount Table? Who will make the determinations in the proposed Sanctions Table to determine the penalty range - NERC/RE staff alone, or with an active role for the SDTs during the standard development process? What is the basis for monetary amounts used in the Sanctions Table?When answers are provided to these questions NRECA will be better able to determine whether it supports these changes.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Manitoba Hydro	No	The maximum penalties appear too high. Specifically, Capability-based requirement pose minimal risk to the bulk electric system and should have lower or no penalties associated with them. Also, it is not clear whether each requirement would be pre-assigned as belonging under Level 1, 2, 3, or 4, or whether this assessment would take place after the violation. If the first instance is true, this would allow less discretion is assessing the extent to which a requirement was violated.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to		

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Kansas City Power & Light	No	The problems and effort required by the SDT and the industry with the current method for VRF and VSL are well stated in the White Paper. The current proposal to eliminate the current VRF and VSL with the "Operations Sanctions Table" is not recommended. The proposed "Sanctions Table" will be subject to debate and interpretation and will be make it difficult to administer and apply. This could lead to an increase in entities and NERC with differences of opinion of the impact of a violation and the subsequent sanction and penalty and lead to an increase of time spent by entities and NERC in appeals. Although it is understood the current process to develop VSL's requires thoughtful consideration and effort, there are some activities in the standards process that are worth the time and effort. The current method for a VSL clearly defines the boundaries for failures and leaves little room for debate and interpretation. There is much value in that for NERC and entities. Further, the current method for VSL's is in direct alignment with performance based requirements. Recommend the current method for VSL's be retained to maintain clarity and avoid interpretation, inconsistent application and ambiguous treatment.The White Paper expresses problems that have been associated with the development and application of VRF's. Although the current method for VRF's may be problematic, this potentially could be overcome with training and education. The White Paper suggested a consideration to increase the number of VRF's from 3 to 5. This would unnecessarily encumber the current process even further and is not recommended. The concepts of requirements that are "Performance Based", "Risk Based", or "Capability Based" and the descriptions of these in the Proposed Standard Manual are attractive. The definitions for these are clear and provide boundary that is useful. Recommend NERC consider replacing the VRF with these as they are well defined and could be directly applied to well written requirements and would help to

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		eliminate the ambiguity and inconsistent application of the current VRF's.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Texas Reliability Entity	No	(1) We do not understand this SPIG proposal, because we do not view VSLs as "redundancies" (redundant with what?). Furthermore, we do not understand how replacing VRFs and VSLs with the proposed Sanction Table addresses the SPIG concern - it merely replaces one process with a different but similar process.(2) We suggest that the proposal to replace VRFs and VSLs should be presented separately from the other SPM revisions and should not be part of the broader SPM revision project. The VRF/VSL proposal will unduly complicate this fast-track project. If presented as a separate project, the proposal to replace VRFs and VSLs can be evaluated on its own merits, and it can be debated deliberately and with due consideration to all of the pertinent issues and alternative approaches.(3) Texas RE understands the value in reducing the burden imposed on Standards Drafting Teams; however, Texas RE believes the proposed Sanction Table and accompanying procedural changes create unnecessary challenges with enforcing Reliability Standard Violations. The proposed Sanction Table represents a significant change in Compliance Enforcement operations and may require considerable procedural, process, and personnel staffing alterations. (4) The language associated with the proposed levels in the Sanction Table is ambiguous, broad, and imprecise.

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		Furthermore, the thresholds to get to Level 3 and Level 4 are unreasonably high. The increased hurdle to reach such upper levels in combination with the indefinite language supporting each proposed level creates unnecessary challenges when implementing this proposal. (5) This proposal would be a move to more ambiguous, broad, and imprecise language than that in existing VSLs ("expected to adversely impact," "could impact," "unlikely to contribute"). Such ambiguous, broad, and imprecise language denies the regulated industry as well as the regional entities clear and concise direction in the enforcement of the NERC Reliability Standards. The Sanction Table will lead to inconsistent implementation and delay violation processing. (6) Similarly, the proposal will provide challenges when comparing the body of FERC-approved violations (and work-in-progress) with future violations enforced according to the proposed Sanction Table. There is nothing in this proposal regarding how Regional Entities, NERC, or FERC will ensure transparent or consistent outcomes. Violation severity levels (or their replacements) should ensure uniformity and consistency among all Standards in the determination of penalties. This proposal resembles a one-size-fits-all solution to a problem that requires nuance and careful, deliberate application. Every enforceable violation presents with a unique fact pattern. The proposal takes a mechanical, simplistic approach to risk. Any proposal in this dynamic NERC Reliability Standard regulatory environment that attempts to use such an approach requires careful examination prior to implementation. This is a significant change for Compliance and Enforcement. If a change of this magnitude is made, Texas RE recommends having more discussion and exploring additional alternatives before such a significant process change is implemented. (7) Texas RE does not see major problems with the existing VSLs, VRFs, or the existing Base Penalty Table. Texas RE does, however, see a problem with a few specific VSLs that could be fixed relatively quickly. In this light, there is value in maintaining the status quo with consideration or emphasis given to only a small subset of VSL or VRFs. Therefore, an alternative proposal is that maintaining the status quo be considered an effective option. However, Texas RE further proposes that Regional Enforcement personnel could provide recommendations to the drafting teams where Enforcement

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		has already identified problems with existing VSLs. This will reduce any undue burden on the Standards Drafting Teams while also gaining the benefits that come from working within an existing, known, process. (8) To address the concern that Standards Drafting Teams are spending too much time and effort drafting VRFs and VSLs, Texas RE proposes that the Regional Enforcement Staffs, particularly the Enforcement, Sanction and Mitigation Working Group (ESMWG), could provide assistance and recommendations to the Standards Drafting Teams in writing and improving the VRFs and VSLs. (9) How does NERC intend for the proposed "Sanction Table reference" for each requirement to be treated in the revised SPM process? Will it be separate from the standard, like VRFs and VSLs are now, and subject to independent NERC and FERC revision; or will it be a full part of the Reliability Standard that is subject to ballot body approval and not subject to revision by NERC and FERC?
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Pepco Holdings Inc.	No	It is not clear with the new sanction tables and the elimination of the VRFs and VSLs, how a determination of a violation would be determined.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have		

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Georgia System Operations	No	We do not believe the changes to the SPM are clear enough to adequately address the SPIG recommendation. We agree that VSLs are in many cases not helpful and that a fundamental change needs to be made instead of fine tuning, but the current proposed revision does not provide enough information to provide a thorough response. More detail is needed on how the Sanction Table would be used. Our understanding is that the SDT would only provide input on the appropriate row of the Sanction Table for each requirement, and that the appropriate column would be determined after reviewing the facts surrounding the actual occurrence. We agree with that approach, but there is nothing in the SPM to indicate that this is actually how it would work. Also, the headings in the Sanctions Table are contrary to that understanding. The first heading in the table is: "a violation is not expected to adversely impact electrical state/capability of BES or ability to monitor/control BES". If the column is evaluated with respect to a specific incident it should refer to "the" violation instead of "a" violation. Also the language "is not expected to" would not be applicable since the event has already occurred; consider replacing it with "did not" or "did not have the potential to". If we are incorrect and the SDT would specify both the column and the row of the table, we disagree with the approach. Different violations of a requirement can vary drastically and should not all be placed in the same column.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that		

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Public Service Enterprise Group	No	The statement in the question that "the revised Standard Process Manual eliminates VRFs and VSLs from the standard template in favor of a Sanction Table Reference (Results-Based Requirement Category Reference) to conserve drafting team and stakeholder resources and ensure consistency in the application of sanctions" will not occur even if the new SPM were passed as written. It would only occur if the proposed sanctions table is adopted to replace the table in Appendix A, Base Penalty Amount Table. Otherwise the result is no change. This is only made apparent by a careful reading of the clean SPM section on page 8 labeled "Standards Table Reference." We believe that is important detail should be made clear to stakeholders.In addition, the SPM should make it clear that the Sanctions Table will be posted with the standard when it is balloted. We therefore suggest a new sentence be added to the first paragraph in Section 4.7 that states "Each new or modified standard will include all the elements of a Reliability Standard as delineated in Section 2.5." With this addition, we would approve the Sanctions Table.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to		

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provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
City of Austin dba Austin Energy	No	Although Austin Energy (AE) does not oppose the concept of Sanctions Tables, we believe the tables ought to be designed differently. More specifically, we believe the Level 3 violation language should read, "Violation IS LIKELY TO contribute to impeding restoration, damaging equipment or non-consequently load loss or IS LIKELY To contribute to BES instability, separation or cascading sequence of failures." Additionally, we believe the Level 4 violation language should read, "Violation CAUSED BES instability, separation or cascading sequence of failures."
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
FirstEnergy Corp	No	1. FE agrees that VRF and VSL are compliance elements that take many hours of drafting team time and should be removed from the process. However, it is not clear how the standard will make reference to this sanction table and what role the drafting team has in tying the requirements to the sanctions table. Furthermore, the sanctions table has a separate section for Cyber Security requirements and

Organization	Yes or No	Question 4 Comment
		references terms to be used in the next version of the CIP standards. Therefore, timing may be an issue since it is not clear how the implementation of this new process and sanctions table will coordinate with the implementation of CIP V5.2. The proposal also involves what appears to be the removal of time horizons from the requirements. Although it was never quite clear how this element was used in compliance violation assessments, we question whether this will be a detriment to the compliance enforcement staff in determining penalties.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Ameren	No	Conceptually the Sanction table can work, but not enough information about process steps are available at this time to make an informed judgment on its development or applicability. Based on what is available now, it seems like there will be too much subjectivity involved. To avoid this subjectivity issue, the SDT would have to develop a recommendation for each requirement in the standard as to which category (Performance, Risk or Capability) should be applicable to it so that SDT's intention is clear to all stakeholders. Our concern is if this is not done by the SDT there will not be uniformity in its application leading to inconsistency in the way auditors and enforcement would apply these Sanction Tables.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that		

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certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
ReliabilityFirst	No	ReliabilityFirst Corporation ("ReliabilityFirst") appreciates the opportunity to comment on the North American Electric Reliability Corporation ("NERC") Standards Committee Process Subcommittee ("SCPS") Proposal (the "Sanctions Table") related to the elimination of the Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"). ReliabilityFirst appreciates how burdensome, lengthy, and difficult the task of drafting VRFs and VSLs can be for the standard drafting teams ("SDTs"). However, the proposed Sanction Table creates unnecessary challenges to the effective and efficient enforcement of mandatory Reliability Standards. First, the requirement that violations must result in an "Adverse Reliability Impact" in order to receive a "Severe" VSL is misguided. Currently, the severity of the violation is related to those compliance activities which are within the control of the registered entity. A failure to undertake such activities could result in the maximum allowable penalty before that failure results in a system event. Thus, the possibility of a "Severe" VSL serves a role in promoting compliance activities that seek to prevent system events without waiting for a system event. Second, Option 1 of the Project introduces a new, undefined term, "reliability purpose," and Option 2 introduces a new, undefined term, "discernible impact on reliability." Under either option, assigning VSLs appears to require a substantive determination regarding the relative impact of a particular violation. Without further guidance, Regional Entities will struggle to apply these terms, resulting in more ambiguity and less consistency than is presently experienced

Organization	Yes or No	Question 4 Comment
		using the current VSLs. Additionally, these ambiguous and undefined terms may result in protracted negotiations with Registered Entities during the settlement process over VSL designations. The use of such ambiguous, broad and imprecise language in the Sanctions Table will result in uncertainty among Registered Entities and ReliabilityFirst regarding enforcement of the NERC Reliability Standards.ReliabilityFirst also believes that the Project will unintentionally undermine reliability because only those violations resulting in an "Adverse Reliability Impact" would be punished with "Severe" VSLs. Additionally, the proposed Pro Forma VSLs introduce new terms that will prove difficult to apply. As an alternative, the ESMWG proposes less drastic revisions to the existing VSLs that would result in more accurate depictions of the severity of a violation. Each possible violation of the Reliability Standards presents unique facts and circumstances which require careful analysis and deliberation. The Sanctions Table, however, is presented as a one-size-fits-all solution to VRFs and VSLs. Such an approach would constitute a significant change in the enforcement of the Reliability Standards and requires very careful examination. ReliabilityFirst does not believe the VRF and VSL matrices are ineffective or broken. Rather, ReliabilityFirst believes the VRF and VSL matrices can and should be improved. There are certain VSLs that can be improved upon which could reduce confusion among Registered Entities and Regional Entities and increase consistency across all the regions. ReliabilityFirst enforcement personnel are willing to assist the SDTs in identifying and improving existing VSLs with identified problems. ReliabilityFirst appreciates the burden and difficulty the SDTs face while drafting VRFs and VSLs as part of Reliability Standards. Therefore, ReliabilityFirst recommends that enforcement staffs from the Regional Entities, particularly the Enforcement Sanction and Mitigation Working Group ("ESMWG"), provide recommendations to the SDTs to improve VRFs and VSLs. Further, the ESMWG could review proposed VRFs and VSLs, thereby streamlining the creation of new VRFs and VSLs while also lessening the VRF and VSL related workload of the SDTs. The Federal Energy Regulatory Commission directed NERC to develop VSLs "either through the Reliability Standards development process or through another expedited process" (emphasis added). The ESMWG in

Organization	Yes or No	Question 4 Comment
		particular could provide this other "expedited process." The ESMWG is positioned to take on this role as its representative implement, enforce, and defend VRFs and VSLs in all enforcement actions. ReliabilityFirst also suggests continuing to explore ways to streamline VRF and VSL drafting to maximize clarity to both Registered Entities and Regional Entities and reduce the burden on the SDTs.ReliabilityFirst supports lessening the burden of drafting VRFs and VSLs during the Reliability Standards development process. However, ReliabilityFirst believes the proposed Sanctions Table is an unnecessary change.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
American Transmission Company	No	ATC does not agree with the sanctions table. Recommendation #4 states that redundancies such as VSL should be considered for elimination. The SPIG did not recommend that VSLs must be replaced with the Sanction table. We are concerned that this sanction table/concept tool has not been properly vetted through compliance personnel. In addition, we would like to see a broader discussion of all the different options to address VSL prior to incorporating any specific solution into the SPM. The VSLs should remain until the Sanctions Tables are vetted properly through the proper channels, with NERC Compliance and Stakeholders.
Response:		

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ISO New England Inc.	No	We agree there is much wasted effort with regard to VRFs and VSLs. But it appears the proposal is to take one confusing process and replace it with another confusing process that has less industry input. It could be made much simpler if the current VRFs were replaced with the "Results Based Categories" and if the VSLs used the pro forma approach developed jointly by the SC and CCC.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Trans Bay Cable LLC	No	This may meet the SPIG recommendation and the approach seems to have merit, but it is unclear how this sanction table might be interpreted by the RE.

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Exelon Corporation	No	Exelon agrees with and supports the EEI comments on the Sanctions Table and VRFs/VSLs.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Xcel Energy	No	1) The dollar range for Level 2 seems disproportional to the others. We suggest removing a zero from the end of both the min and max range, in all 3 tables.2) Since there appears to be confusion regarding how these sanction tables might impact FFT treatment, we recommend a footer be added (or clarification in the white papers) to clarify that the sanction tables are not used for FFT candidates, as they are not

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		assessed a penalty at all. (Versus $0 penalty)3) Recommend adding another level for items that have no impact on reliability, with a starting value of $0. Currently, the criteria for FFT treatment could still allow a "no impact on reliability" violation to not qualify for FFT treatment. In those cases, enforcement staff should have a level that accurately reflects the circumstances of the violation.4) It would be helpful if more transparency were provided on the discount range for various mitigation actions. (Comparable to a 0-20% good driver discount on auto insurance.) This could be as simple as a non-exhaustive list of most common mitigating actions. We feel this will proactively promote better behavior, and give entities a better idea of expected outcome after a violation has occurred.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Bonneville Power Administration	Yes	BPA is in agreement and support of continued analysis on the Essential Elements of the Standards template and is encouraged with this proposal.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to		

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provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
National Grid and Niagara Mohawk (A National Grid Company)	Yes	National Grid supports the elimination of VSLs in favor of a table in the format of the proposed Results-Based Sanction Table; however, National Grid opposes some of the language proposed in the "Level" descriptions of the table. National Grid recommends the following changes to the table: 1) The name of the table should be changed to "Results-Based Sanction Table Guideline" and each section of the table should include the word "guideline" i.e. "Operations Sanction Table Guideline"; "Cyber Security Sanctions Table Guideline" ; "Planning Sanctions Table Guideline". This change would ensure that those using the table understand that the sanctions presented are not mandatory, fixed penalty amounts, but are a guideline or starting point for a baseline penalty. This aligns with the existing NERC Sanctions "Guideline". National Grid assumes that this table will eventually be incorporated into the Rules of Procedure as part of the NERC Sanctions Guideline, but if the table will be used as a guidance document prior to that time, then the name of the table should be changed to ensure the table is correctly applied correctly. 2) The 'Cyber Security' Sanctions Table should remove references to Low, Medium, and High Impact BES Cyber Systems from the "Level" descriptions. These references will perpetuate one of the major existing problems with the VSL table - i.e. the overstatement of severity of minor violations resulting in higher-than-necessary baseline penalties. By matching the Levels to Low, Medium, or High Impact Elements, any violation of the standard associated with a certain facility, even a mere documentation error, will fall into the Level assigned to that asset. For example, a documentation error that causes little to no risk to the BES that is related to a requirement applicable only to High Impact BES Cyber Systems will fall into Level 3

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		with a high penalty range. In the current draft of CIP Version 5, most of the requirements are applicable only to Medium and High Impact systems; thus, nearly all violations will fall into Level 2 or Level 3 on the proposed table regardless of actual risk. This is not commensurate with the purported purpose of the table as a substitute for VSLs. The remaining language in the table, without the references to affect on Low, Medium, and High Cyber Systems, is sufficient to allow the Regional Entity to asses the impact of a violation of a CIP standard on the BES. The references should be removed. 3) "Other" should be removed from the 'Cyber Security' Sanctions Table in the Performance-based category. The term is too broad. If there are performance-based type requirements other than "acts to protect cyber assets" then they should be spelled out. 4) In the 'Planning' Sanctions Table, the Level 3 and Level 4 language should be modified. Violations of planning requirements occur when an entity fails entirely to have a required plan or fails to have a sufficient plan (one having all required elements). The language should be modified to be more clear so that the focus is on whether the plan is sufficient according to the terms of the standard. As drafted, the language could be read to mean that a plan with all required elements that for some reason does not achieve desired results could be penalized. The following language is recommended: Level 3 - a violation results in a plan that is insufficient pursuant to the requirements of the standard and the plan's insufficiency could contribute to an adverse affect on the BES' ability to respond to contingencies. Level 4 - a violation results in a plan is insufficient pursuant to the requirements of the standard and the plan's insufficiency could directly cause an adverse affect on the BES' ability to respond to contingencies.In addition to the above modifications to the table, National Grid recommends that a transition team be put into place in order to review existing standards for designation and categorization of the existing requirements in accordance with the new table. This will shorten the transition period between use of the VSLs for existing requirements to enabling use of the new table. If the team identifies requirements that do not fit into a category, the team can recommend

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		those requirements for future modification. National Grid realizes that a transition team of this sort requires resources and will need to be prioritized appropriately in light of other ongoing standards development projects. However, continuing to use the VSLs for existing standards until the standards happen to be due for amendment will unnecessarily drag out the transition period where both VSLs and the new Results-Based Table will be used. Considering the problems with applying the VSLs that have been identified, National Grid suggests it would be wise to devote some resources to shortening this transition period as much as possible.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Florida Municipal Power Agency	Yes	Sanctions Table: FMPA supports the table, supports the distinction between performance, risk and capability based requirements, and generally supports the 4 levels/columns identified. FMPA's concern springs from the use of the word "could" in the Levels. FMPA understand that some subjectivity is necessary in determining the Levels, but, the word "could" is too "soft" of a word that leaves too much subjectivity in the process. FMPA recommends the use of "expected" as used in the Level 1 description of the Operations Sanction Table, e.g., Level 2 in the Operations Sanction Table would be re-worded to say: "a violation under reasonably assumed conditions would be expected to directly and adversely impact ...". Also, a more minor comment on the Planning Sanctions Tables, the word "contingencies" should

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		be qualified with “applicable contingencies”FMPA is concerned about transition. How will existing standards be transitioned to this new method? Will we be living in two worlds in the mean-time?
Response: Thank you for your support. Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Arizona Public Service Company	Yes	Yes, the elimination of VRF and VSL is a good idea. VSL’s are currently being misused. Drafting teams are forced to assign medium VRF’s for any requirement other than purely administrative no matter how small is the impact. VSL’s are getting very complicated and have become arbitrarily time based even though reliability impact is not proportional to delay in executing.
Response: Thank you for your support. Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best		

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manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
American Electric Power	Yes	In general, we support the direction that SPIG is taking in regards to eliminating VRFs and VSLs from the standard template in favor of a Sanction Table Reference. While this effort is taking place, we believe it is an opportunity to encourage SPIG to evaluate the current compliance practice that requires 100% compliance at all times, specifically in regards to requirements that have a very large scope and application. For example, these standards have driven entities to track many thousands of individual due dates which must all be met in order to be fully compliant. To track and meet this volume of distinct parameters is not only extremely challenging, but creates a statistical certitude that violations will occur. We suggest that future standards be developed in such a way that promotes the reliability of the BES in a manner which yields a more reasonable volume of milestones and deliverables to track and meet.
Response: Thank you for your support. Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
NextEra Energy Inc	Yes	NextEra agrees with the elimination of VSLs; however, NextEra recommends specific edits to the new Sanctions table. See NextEra's response to question 6, below.
Response: Thank you for your support. Based on the majority of the comments received, the SCPS has re-examined the proposed		

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Illinois Municipal Electric Agency	Yes	Illinois Municipal Electric Agency (IMEA) supports comments submitted by Florida Municipal Power Agency.
Response: Thank you for your support. Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Duke Energy	Yes	The proposal has the potential to increase the efficiency of the Standard Drafting Teams and allow them to focus their time and effort more productively. Care will need to be taken in further development of the so called “Sanction Table” to ensure that the ranges defined are consistent with previously assessed penalties and with the current Base Penalty Amount table. This appears to be an opportunity to more tightly couple the results of compliance assessment with the actual risk to reliability.

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Response: Thank you for your support. Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
ACES Power Marketing Standards Collaborators	Yes	-1- Since there is little correlation between actual penalties issued to date and the sanctions table (and by extension VSLs and VRFs), this makes sense. Furthermore, VRFs are often skewed high based on what could happen if the requirement is violated, not what is likely to happen. Finally, VSLs rarely represent the full spectrum of violations that could occur which requires enforcement personnel to use their judgment in assigning a VSL anyway. Eliminating VRFs and VSLs should save all stakeholders time in the standards development process. -2- We do have one concern, however, regarding the sanctions table. The sanctions table should reflect differing penalties depending on whether or not a negative consequence has occurred. This accommodation exists in other areas of the law. For example, an attempted crime generally does not carry the same level of penalty as an actual crime.
Response: Thank you for your support. Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to		

Organization	Yes or No	Question 4 Comment
provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
AECI and the G&T members Central Electric Power Cooperative, KAMO Power Cooperative, M&A Electric Power Cooperative, Northeast Electric Power Cooperative, NW Electric Power Cooperative, and ShoMe Power Electric Cooperative	Yes	AECI supports removing the VSLs from the SPM and going to a sanctions table.
Response: Thank you for your support. Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
SPP Standards Review Group	Yes	
Salt River Project	Yes	

Organization	Yes or No	Question 4 Comment
Liberty Electric Power	Yes	
Oklahoma Gas & Electric	Yes	
Essential Power, LLC	Yes	
PPL Corporation NERC Registered Affiliated		The PPL Companies are not convinced that the proposed Sanction Table is an improvement over the current Base Penalty Amount Table integrated with the VRFs and VSLs.VSLs for some standards have specific numeric divisions which reduce subjectivity in the application of VSLs. Increasing the need for subjectivity in the penalty determination process is not consistent with development of an expeditious, transparent penalty application process.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Independent Electricity System Operator		While this seems like a much simpler approach and we understand how the change will conserve resources insofar as SDTs are concerned, we can't see how it will ensure consistency in application of sanctions; we are concerned that it will blur the landscape quite a bit and leave it entirely up to the auditors/investigators to apply those sanction guidelines in the context of each standard and situation.

Organization	Yes or No	Question 4 Comment
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Flathead Electric Cooperative, Inc.		This may meet the SPIG recommendation and the approach seems to have merit, but it is unclear how this sanction table might be interpreted by the RE.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
NERC		NERC Staff Compliance Operations and Enforcement comments:The Standards Process Input Group (SPIG) organized by the NERC Member Representatives Committee (MRC) proposed a number of recommendations for changes to the way NERC develops Reliability Standards. One of the specific recommendations to improving the NERC Standard Development Process is revising the essential elements

Organization	Yes or No	Question 4 Comment
		of the Standards Template to eliminate redundant or unnecessary activities, such as drafting of Violation Severity Levels (VSLs). NERC Enforcement supports efforts to improve the Standard Development Process.There have been several proposals to accomplish this objective. One proposal offered by the NERC Standards Committee Process Subcommittee (SCPS), and the subject of this comment process, would revise the existing NERC Base Penalty Amount Table to eliminate the Violation Risk Factor (VRF) and the VSL. Another proposal introduces the development of a pro forma VSL while retaining the existing VRFs. It is likely that additional approaches will be offered during this comment period.While NERC Compliance Operations and Enforcement staff is not at this time specifically endorsing any of the proposals presented, there are several principles that each proposal should meet to ensure that the process is effective and can be administered by NERC and Regional Entity enforcement and complies with FERC orders: o The approach should contemplate existing FERC guidelines on setting VRF/VSL levels and defining base penalty amounts.[1] We would note that FERC has articulated a number of fundamental principles communicated in these guidelines, including:o Penalty amounts must be per violation, per day not per violation, per occurrence;o A penalty level of $1M per violation, per day must be available for serious violations;o VSLs should not have the unintended consequence of lowering the current level of compliance;o VSLs should be based on a single violation, not on a cumulative number of violations;o VRF/VSLs should ensure uniformity and consistency within and among reliability standards;o VRF/VSLs must have a single, consistent description;o Risk factor assignment should not allow a watering down of the VRF where a requirement co-mingles more than one obligation;o Any approach should permit discouraging economic choice to violate a reliability requirement based on penalty amount; ando Any approach should recognize a risk is not minimal simply because there was no adverse impact to the Bulk Power System or if it reveals a serious shortcoming in a registered entity's reliability-related processes.[2] o Any approach should address risk and harm levels in the base penalty determination. o Penalty matrix must permit access to all levels of violation risk/severity for a given violation. o The proposal should ensure

Organization	Yes or No	Question 4 Comment
		consistency with past penalty determinations and the calculation of future penalties. This should be demonstrated by sample calculations under the existing and proposed approaches. o Level definitions must be clear and concise and not create ambiguities that could delay settlement negotiations or engender a lack of clarity in base penalty calculations. o Elements comprising the base penalty determination should be as objective as possible. o The base penalty calculation process should not re-write the standards/requirements to which they apply. o The process should be straight-forward and intuitive in application.NERC Compliance Operations and Enforcement staff believe that the proposals presented through this comment process should receive full consideration, in light of the basic elements presented above, and looks forward to working with the Regional Entities and the industry in their evaluation.---end notes ---[1] Orders addressing FERC guidance on VSL/VRFs include: Order on Violation Severity Levels Proposed by the Electric Reliability Organization, 123 FERC Â¶ 61,284 (June 19, 2008); Order on Rehearing and Clarification and Accepting Compliance Filing, 125 FERC Â¶ 61,212 (November 20, 2008); Order on Compliance and Rehearing, 135 FERC Â¶ 61,166 (May 19, 2011); Order Addressing Violation Severity Level Assignments for Critical Infrastructure Protection Reliability Standards, 130 FERC Â¶ 61,211 (March 18, 2010); Order on Violation Risk Factors, 119 FERC Â¶ 61,145 (May 18, 2007); Order on Rehearing and Compliance Filing, 120 FERC Â¶ 61,145 (August 9, 2007); Order Accepting with Conditions the Electric Reliability Organization's Petition Requesting Approval of New Enforcement Mechanisms and Requiring Compliance Filing, 138 FERC Â¶61,193 (March 15, 2012); and Order on Compliance Filing, 118 FERC Â¶61,030 (January 18, 2007).[2] The Commission has also provided the following guidance specific to a cyber security context: 1) a binary VSL, rather than a graduated VSL, should be applied for requirements where a single lapse in protection can compromise computer network security and 2) VSLs for interdependent tasks should account for the interdependence.
Response: Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-		

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binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise (NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.		
Indiana Municipal Power Agency		no comment

5. **As part of Recommendation 4, the SPIG encouraged NERC to ensure the cost effectiveness of standards through documentation of alternatives analysis.**

   A Cost Effective Analysis Proposal (CEAP) was posted for industry comment on May 7, 2012, through July 6, 2012. Does this draft document adequately address the SPIG Recommendation? If not, please explain why and offer an alternative solution for ensuring the cost effectiveness of standards through documentation of alternatives analysis.

Summary Consideration:

Many entities have submitted a complete set of comments in response to a separate posting of the CEAP, and a thorough summary of all comments received will be provided in the Consideration of Comments for that posting. The Cost Effectiveness Analysis Process ("CEAP") is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	The revision does not reference the CEAP, therefore not adequately addressing the SPIG recommendation. The CEAP is a separate and proposed guideline document not referred to in this Standard Processes Manual.
Response: Thank you for your comment. The Cost Effectiveness Analysis Process ("CEAP") is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's		

Organization	Yes or No	Question 5 Comment
intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (e.g. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
IRC-SCR	No	We agree that the CEAP as proposed is a good start. Since the changes to the SPM were to support the SPIG recommendations. The "steering group" and the concept of cost effectiveness need to be brought into Section 4 (Process for Developing, Modifying or Retiring a Reliability Standard"). The underlying precept of the SPIG is that we need to move away from a volumetric approach to standards, to a focused development of standards that add value and provide an ALR. As part of the SAR process, there needs to be a triage that clearly addresses what's missing in ALR, and how the standard will provide it. The process of opening a solicitation every year seeking ideas for new Standards Development proposals should be stopped. The industry is overwhelmed with standards actions. If the issue is important enough to be a standard, a SAR should be submitted.
Response: Thank you for your comment. The Charter for the Reliability Issues Steering Committee, (RISC), is not under the purview of the Standards Committee and is not part of the standard development process. The draft charter and initial slate for the RISC was approved by the NERC BOT in August and the SC looks forward to clarifying the relationship between the SC and RISC. The Standards Committee (SC) acknowledges that there will be a necessary interface coordination to be implemented in order to assure effective coordination between the activities of the RISC and those of the SC.		
Hydro One	No	The revision does not reference the CEAP so does not adequately address the SPIG recommendation. The CEAP is a separate and proposed guideline document not referred to in this SPM.
Response: Thank you for your comment. The Cost Effectiveness Analysis Process ("CEAP") is not incorporated into the proposed revisions to the Standard Processes Manual.		

Organization	Yes or No	Question 5 Comment
It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (e.g. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
AECI and the G&T members Central Electric Power Cooperative, KAMO Power Cooperative, M&A Electric Power Cooperative, Northeast Electric Power Cooperative, NW Electric Power Cooperative, and ShoMe Power Electric Cooperative	No	AECI does not believe that the CEAP has been adequately described and it needs further development. Industry should be the ones overseeing the documents and deciding when they are ready for SC or RISC review and consideration, not NERC. This question in the SPM Comment form is premature. The CEAP ballots comments are just now being reviewed, July 26 & 27. There are a number of CEAP provisions that need additional work. We need to wait for the CEAP comment and revision process to play out before balloting it on another document like this SPM comment form. NERC has not taken the time needed to appropriately develop this topic.
Response: Thank you for your comments and we agree that the CEAP is in a developmental stage. The Cost Effectiveness Analysis Process ("CEAP") is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		

Organization	Yes or No	Question 5 Comment
Florida Municipal Power Agency	No	The CEAP was not really a Cost "Effective" Analysis Proposal, but really a Cost Analysis Proposal without sufficient consideration of "Effective"ness. While a good start, the CEAP ought to be revised to include effectiveness of investment at accomplishing reliability goals.
Response: Thank you for your comment. The Cost Effectiveness Analysis Process ("CEAP") is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual. There is nothing in the current proposed CEAP that would prohibit an entity from including in its CEAP survey responses comments regarding more cost effective solutions to achieve reliability goals. This is the type of feedback the CEAP is designed to solicit. The purpose statement of the CEAP document will be revised to clarify this goal.		
Edison Electric Institute	No	EEI submitted the following comments on the cost effectiveness analysis proposal on July 16:EEI appreciates that practical discussions have begun for beginning to more explicitly consider the costs of potential new requirements or modifications to existing requirements in mandatory standards. This is a welcome change. Any management decision needs to have a clear sense of the goal being addressed by a specific initiative, options for addressing the matter, the costs of the various options, and the measures of success. The specificity of the information needed for decision-making will vary depending on the questions under consideration. Initial impressions of the proposal for considering costs and cost effectiveness: To the maximum extent practicable, the general framework for considering potential costs of a new or

Organization	Yes or No	Question 5 Comment
		modified standard should be designed to include both a) general characterizations of investments, and operation and maintenance expenses that would be required, and b) general characterizations of the reliability goals, risks, and contingencies that would be addressed. This could be included in what we understand as the 'phase one' part of the process described to date. EEI also envisions that discussion of these issues should include the newly formed Reliability Issues Steering Group (RISC), as well as standing technical committees that would have an already assembled group of technical expertise that could be tapped for advice and counsel. RISC would also have a natural interest in its normal course of considering reliability issues and risks from a high-level strategic perspective. RISC should be prepared to offer its views on potential standards development projects, including potential costs and benefits. In addition, and in order to begin relevant discussions as early as possible, EEI envisions that FERC staff should be invited to these discussions in order to begin developing shared understandings of both the reliability objectives, and potential costs. As a general matter, we have long believed that proactively engaging the regulatory entities sooner and not later is an important element for shaping successful outcomes. EEI envisions that a SAR will include a description of the kinds of fixed investments, operations and maintenance expenses, or administrative expenses that might be needed to cover any new or modified requirements. The SAR should also include a description of the incremental reliability benefit, including the reliability risk or problem being addressed. It would be the responsibility of the SAR sponsor to make state these general descriptions. As a general matter, we envision that this would be possible with no more than 500 words, that is, not a detailed cost estimate or surgically precise specification. SAR content should also describe performance outcomes that would be expected as a result of compliance, including characterizations of performance that would be viewed as violations. Upon approval of the project and development of more detailed language for the standard, the balloting and commenting phase could seek some refinement of the characterizations of costs and benefits. While the process proposal would seek to

Organization	Yes or No	Question 5 Comment
		gather this information from individual entities, EEI proposes that relevant NERC technical committees perform this exercise. Nothing should prevent NERC from seeking comments from individual entities; however, some may prefer to not provide more detailed information. In addition, at this time we are not convinced that detailed cost estimates are needed. We are also concerned that cost estimate activities not become over-engineered to the point that companies are compelled to make what might be considered to be good faith cost estimates on activities that will take place over long periods of time. Upon filing at FERC, NERC should have gathered information sufficient to plainly describe the reliability problem being addressed, the manner in which the proposed standard will address the problem, the performance expectations, as well as the kinds of investments and expenses likely to be undertaken that would not occur otherwise. Detailed engineering estimates or creating new bureaucracy should not be the goals in this exercise. Nor should companies be held to rough cost estimates that may be offered in response to general analysis of a potential reliability matter.

Response: Thank you for your comment.

The Cost Effectiveness Analysis Process ("CEAP") is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made.

After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.

Changes to the SAR format are not being addressed as part of the CEAP project. While including anticipated investment requirements and performance outcomes in a SAR might be considered in the future, these inclusions would only present the data as analyzed by the entity or entities sponsoring the SAR and would not provide the type of industry-wide, high-level cost effectiveness

Organization	Yes or No	Question 5 Comment
information that the CEAP seeks. The CEAP 's success is dependent on Trade Groups such as EEI promoting and encouraging their members to respond to SAR and SDT information requests to provide the assistance in identifying alternative solutions that meet the reliability objective of the draft standard that the CEAP should facilitate. The RISC Charter, currently under development may also be an integral part of the CEAP. Recently a meeting was conducted with FERC staff and it was emphasized to Commission staff that this is not a purely analytical tool and is based on good faith estimates provided by the industry. We agree that all estimates used in the CEAP should be considered only high level approximations to provide examples of what costs "may" be. Finally, the Charter for the Reliability Issues Steering Committee, (RISC), is not under the purview of the Standards Committee and is not part of the standard development process. The draft charter and initial slate for the RISC was approved by the NERC BOT in August and the SC looks forward to clarifying the relationship between the SC and RISC. The Standards Committee (SC) acknowledges that there will be a necessary interface coordination to be implemented in order to assure effective coordination between the activities of the RISC and those of the SC.		
Arizona Public Service Company	No	There is no mention of CEAP in this document. There should be additional discussion of how the recommendation is applied.
Response: Thank you for your comment. The Cost Effectiveness Analysis Process ("CEAP") is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
Occidental Energy Ventures Corp. (OEVC) and Electricity Consumers Resource Council (ELCON) together called	No	Industrial Consumers agree that cost/benefit analysis of a proposed standards development effort is a critical part of sensible regulation. If properly performed, the efforts with the highest return on reliability can be addressed as a top priority - with some measurable economic justification behind them. Industrial Consumers have

Organization	Yes or No	Question 5 Comment
Industrial Consumers		submitted comments on the CEAP and incorporate those comments by reference into these comments.
Response: Thank you for your comment. Your separately submitted comments on the CEAP will be addressed in that Comment Report. The CEAP is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
National Rural Electric Cooperative Association (NRECA)	No	NRECA and other industry stakeholders recently submitted comments on the CEAP. From NRECA's standpoint, until we see how our comments, and comments from others, are addressed, we are unable to state whether the CEAP adequately addresses the SPIG recommendation and whether it appropriately addresses the cost-effectiveness issues that are associated with standard development and compliance responsibilities.
Response: Thank you for your comment. Your separately submitted comments on the CEAP will be addressed in that Comment Report. The CEAP is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made.		

Organization	Yes or No	Question 5 Comment
After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
Liberty Electric Power	No	Comments provided in the CEAP comment form regarding cost differentials due to entity size and structure.
Response: Thank you for your comments. Your separately submitted comments on the CEAP will be addressed in that Comment Report. The CEAP is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
Texas Reliability Entity	No	We agree that alternatives analysis should be an important consideration in the standards process, but we feel the proposed CEAP goes well beyond what is required and adds complexity and work that is counterproductive to the overall effort to streamline and simplify the process. In short, we think the proposed CEAP is not cost-effective, that is, it will not provide benefits commensurate with the amount of effort required to do it right. And if it is not done right (which is a very real risk) then it will be wasted effort. We propose simply requiring each drafting team to produce a documented "alternatives analysis" explaining the alternatives they considered and why one was selected over the others.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. The Cost Effectiveness Analysis Process ("CEAP") is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual. We do agree that the CEAP needs to be done properly. The CEAP as proposed is intended to solicit high level information to supplement the standards development process. The information collected via the CEAP should enable drafting teams to evaluate alternatives, even if a formal "alternative analysis" is not included in the final drafting team product. This type of analysis may not be possible without the input from the industry that the CEAP solicits. We agree that there will be additional burden for the industry. We believe that the benefits of the CEAP outweigh the additional burden on the industry and that the CEAP is not *overly* burdensome because it is high-level. The success of the CEAP pilot will help determine how the project moves forward.		
NextEra Energy Inc.	No	Please see NextEra's comments filed on the CEAP.
Response: Your separately submitted comments on the CEAP will be addressed in that Comment Report.		
Flathead Electric Cooperative, Inc.	No	This Cost Effective Analysis Proposal is a good first step at giving a price tag to each of these standards. However, it is unclear what happens if the price tag is high and where does the consumer-elected governing body or state regulators have a say in whether that cost is worth the price. Regardless the analysis of the cost is a good first step. It is unclear if the information would be gathered early enough in the process of developing a standard for a standard to be cancelled due to cost concerns. Although, it would be difficult to pre-determine the cost of a standard that may change significantly in the development process, thereby increasing its regulatory cost

Organization	Yes or No	Question 5 Comment
		burden. Generally, support the direction of the CEA proposal, but the issue of FERC exercising its reliability authority in areas where it does not also have rate making authority has created a situation whereby costs are created in a mandatory fashion, but the source of funding is an after-thought. Depending upon the outcome of the BES definition process, this tension may be eased somewhat if the focus returns to the bulk transmission system where FERC has more defined rate making authority.
Response: Thank you for your comment. The CEAP is not currently intended to determine whether or not a standard should go forward based on cost. Within Phase 1, the SAR will identify the reliability gap along with cost effective proposed methods to improve reliability. In Phase 2 the cost effectiveness of alternative methods will be identified by the SDT and industry that could satisfy the standard requirements. The Cost Effectiveness Analysis Process ("CEAP") is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
Georgia System Operations	No	There is insufficient detail in the CEAP proposal to provide substantive input. A more detailed vision of the plan to implement this proposal is needed. We recommend doing an informal trial of this approach on a small number of selected standards and developing a more detailed proposal based on the results of that trial. We emphatically agree that it is advisable to include consideration of cost-benefit in the development or revision of Reliability Standards.
Response: Thank you for your comment. The Cost Effectiveness Analysis Process ("CEAP") is not incorporated into the proposed revisions to the Standard Processes Manual.		

Organization	Yes or No	Question 5 Comment
It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
Public Service Enterprise Group	No	We do not support the CEAP as written. Please see our separately submitted comments on the CEAP matter.
Response: Thank you for your comment. Your separately submitted comments on the CEAP will be addressed in that Comment Report.		
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency (IMEA) supports comments submitted by Florida Municipal Power Agency.
Response: Thank you for your comment. The Cost Effectiveness Analysis Process ("CEAP") is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		

Organization	Yes or No	Question 5 Comment
City of Austin dba Austin Energy	No	AE strongly agrees with the idea of employing a cost/benefit analysis before creating new standards or revising existing standards. However, we believe the proposed CEAP will create too much additional burden on the industry. We recommend following the Phase I ("Cost Impact Analysis") as currently proposed (i.e. the "high level" analysis) and then, instead of going directly to the "Cost Effectiveness Assessment" (CEA), asking industry members if they believe a CEA is necessary before proceeding.
Response: Thank you for your comment. It is currently proposed that the CEAP process will be conducted in tandem with the normal standards development process and questions posed during the applicable comment periods for SAR and Standard will capture the information necessary. We believe that the benefits of the CEAP outweigh the additional burden on the industry and encourage entities of all sizes and resource levels to participate as much as possible and to take advantage of pooling comments and industry trade groups for submitting comments. It is anticipated that all entities may benefit from any information that is submitted by other entities, and the more entities that are able to submit will increase these overall benefits. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). One of the issues that will be considered in the future is whether there should be a threshold for conducting a CEA. A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
FirstEnergy Corp	No	FE agrees that a formal process for cost effectiveness should be considered during the development of any new and revised Reliability Standards. An adequate level of reliability (benefits) versus the cost of implementing the standard should be used to determine whether a standard will continue through the various standards process development. However, it is unclear if the phrase "this draft document" in this question is referring to the CEAP or the Standard Process Manual, we assume the latter. In section 4.1 it's indicated that a SAR will require "a discussion of the

Organization	Yes or No	Question 5 Comment
		reliability-related benefits and costs of developing the new Reliability Standard". The SPM should be adjusted to footnote the CEAP process for the cost/benefit analysis that must be performed.
Response: Thank you for your comment. The reference to "this draft document" is in fact referring to the SPM posting in this context. Regarding the reference to addition of the footnote, it is planned that the CEAP Document recently posted for comment in the NERC process is currently envisioned to be a separate guideline document as "part of" the considerations the NERC Standards Committee and Standard Drafting Teams will use as they develop standards. The CEAP is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
Ameren	No	In principle we agree but clarification on how CEAP process will work is still needed. We had reviewed and provided comments separately on another NERC CEAP proposal. We suggest that the SDT should coordinate with that project.
Response: Thank you for your comment. Your separately submitted comments on the CEAP will be addressed in that Comment Report. Clarification: There is only one CEAP proposal. The separate posting ending on July 6, 2012 is the same CEAP that is referred to in this SPM request for comment.		
Indiana Municipal Power Agency	No	Indiana Municipal Power Agency supports the comments submitted by Florida Municipal Power Agency.
Response: Thank you for your comment. Please see the response to FMPA comments.		

Organization	Yes or No	Question 5 Comment
ISO New England Inc.	No	We agree that the CEAP as proposed is a good start. Since the changes to the SPM were to support the SPIG recommendations. The "steering group" and the concept of cost effectiveness need to be brought into Section 4 (Process for Developing, Modifying or Retiring a Reliability Standard"). The underlying precept of the SPIG is that we need to move away from a volumetric approach to standards, to a focused development of standards that add value and provide an ALR. As part of the SAR process, there needs to be a triage that clearly addresses what's missing in ALR, and how the standard will provide it. The process of opening a solicitation every year seeking ideas for new Standards Development proposals should be stopped. The industry is overwhelmed with standards actions. If the issue is important enough to be a standard, a SAR should be submitted.
Response: Thank you for your comments. The concept of a Reliability Issues Steering Committee or "RISC" is being developed which is envisioned to actively Triage newly identified reliability issues and standards development projects. Also, the Charter for the Reliability Issues Steering Committee, (RISC), is not under the purview of the Standards Committee and is not part of the standard development process. The draft charter and initial slate for the RISC was approved by the NERC BOT in August and the SC looks forward to clarifying the relationship between the SC and RISC. The Standards Committee (SC) acknowledges that there will be a necessary interface coordination to be implemented in order to assure effective coordination between the activities of the RISC and those of the SC. As the SPM continues to be revised, additional consideration will be given to the issues you have identified.		
Trans Bay Cable LLC	No	This Cost Effective Analysis Proposal is a good first step at giving a price tag to each of these standards. However, it is unclear what happens if the price tag is high and where does the consumer-elected governing body or state regulators have a say in whether that cost is worth the price. Regardless the analysis of the cost is a good first step. It is unclear if the information would be gathered early enough in the process of developing a standard for a standard to be cancelled due to cost concerns. Although, it would be difficult to pre-determine the cost of a standard that may change significantly in the development process, thereby increasing its regulatory cost burden. Generally, support the direction of the CEA proposal, but the issue of FERC exercising its reliability authority in areas where it does not also have rate making

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		authority has created a situation whereby costs are created in a mandatory fashion, but the source of funding is an after-thought. Depending upon the outcome of the BES definition process, this tension may be eased somewhat if the focus returns to the bulk transmission system where FERC has more defined rate making authority.
Response: Thank you for your comment. The CEAP is not currently intended to determine whether or not a standard should go forward based on cost. Within Phase 1, the SAR will identify the reliability gap along with cost effective proposed methods to improve reliability. In Phase 2 the cost effectiveness of alternative methods will be identified by the SDT and industry that could satisfy the standard requirements. The CEAP is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
Exelon Corporation	No	In the CEAP comment period, Exelon raised a number of questions about the CEAP including questions about its role relative to the SPM. There is no mention of the CEAP in the proposed SPM. It remains unclear how these two components will interact and be effectively utilized. More information is needed to assess.
Response: Thank you for your comment. The CEAP is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP		

Organization	Yes or No	Question 5 Comment
project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
ACES Power Marketing Standards Collaborators	Yes	We indicated in our comments on the CEAP that it represents a good start for a cost measure that will ultimately need further refinement. Considering the recommendation is high-level, CEAP probably does meet the recommendation.
Response: Thank you for your supportive comment. The CEAP is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
MRO NSRF	Yes	The NSRF agrees with the SPIG recommendation to ensure cost effectiveness of the standards, but notes that the CEAP process should not delay the standards development process.
Response: Thank you for your comment. It is currently proposed that the CEAP process will be conducted in tandem with the normal standards development process and questions posed during the applicable comment periods for SAR and SDT activities will capture the information necessary to evaluate the CEAP impact. A CEAP pilot project is proposed for a couple of standard projects and more information regarding any potential delays will be identified at that time.		

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The CEAP is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
SPP Standards Review Group	Yes	We are very much in favor of factoring cost consideration into the standard development process. Please refer to our comments that were filed during the CEAP posting and comment period for specific questions, suggestions and comments.
Response: Thank you for your comment. Your separately submitted comments on the CEAP will be addressed in that Comment Report. The CEAP is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
Bonneville Power Administration	Yes	BPA appreciates the Standards Committee's work on this. BPA recognizes that this project will be a continuous improvement process.
Response: Thank you for your support of the project and we agree that over time, much like the standards development process,		

Organization	Yes or No	Question 5 Comment
opportunities for improvement will be identified and revisions proposed. The Cost Effectiveness Analysis Process ("CEAP") is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
SERC Planning Standards Subcommittee	Yes	We agree that there should be a cost effectiveness process included in the standards development process. However, comments on the proposed CEAP are being collected in a separate posting.
Response: Thank you for your comment. Your separately submitted comments on the CEAP will be addressed in that Comment Report. The CEAP is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
Oklahoma Gas & Electric	Yes	We encourage NERC to factor cost consideration into the standard development process.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your support of this project. The Cost Effectiveness Analysis Process ("CEAP") is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
American Transmission Company	Yes	ATC agrees with the SPIG recommendation to ensure cost effectiveness of the standards, but notes that the CEAP process should not delay the standards development process. ATC is not clear as to how the CEAP will be incorporated so that the development process is not delayed.
Response: Thank you for your comment. It is currently proposed that the CEAP process will be conducted in tandem with the normal standards development process and questions posed during the applicable comment periods for SARs and Standards will capture the information necessary. A pilot will be completed to gather additional experience and gather more information regarding any potential delays. The CEAP is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will		

Organization	Yes or No	Question 5 Comment
respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
Western Electricity Coordinating Council	Yes	
Salt River Project	Yes	
Manitoba Hydro	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
Pepco Holdings Inc.	Yes	
ReliabilityFirst	Yes	
Essential Power, LLC	Yes	
Dominion		The Cost Effective Analysis Proposal is currently posted for industry comment and Dominion intends to file comments there.
Response: Thank you for your comment. Your separately submitted comments on the CEAP will be addressed in that Comment Report.		
PPL Corporation NERC Registered Affiliated		While the PPL Companies support a greater consideration of the cost/benefits of a revision or creation of a standard, the PPL Companies have some concerns with the CEAP: a. In Step 1, the responsibility of providing a report and recommendation based upon the CIA questions in Appendix B should not rest with NERC Staff, but with industry

Organization	Yes or No	Question 5 Comment
		SMEs. In Step 4, the report and recommendation should not be provided by NERC Staff, but by industry SMEs. However, NERC staff should be available to support the SMEs work. b. Responses to the questions in Appendix B should be reported separately for each of the groups covered by the draft standard (GOs, TOs, TOPs, etc., as applicable), not as a single figure for all of industry. This will help identify where standards that may be acceptable on an aggregate basis involve placing an excessive burden on one segment of the stakeholders. In addition, the cost/benefit analysis should consider different industry and organizational structures. For example, the burdens placed on a vertically-owned utility and an independent generator for a particular standard may be very different. Additionally, there are differences between ISO/RTO and non-ISO/RTO regions (e.g., black start compensation). Such differences should be considered in assessing the cost and benefits. c. If there are significant differences in costs and benefits between phase 1 and 2, a third phase consisting of a NERC-funded pilot at volunteer entities could be helpful in obtaining greater certainty on actual costs and benefits. d. The phase 1 and 2 inquiries should have added to them the question, "Are there alternative measures that would demonstrate compliance in a less burdensome manner than those presently proposed, or re-phrasings that would eliminate uncertainty?" This aspect of compliance is oftentimes not as well developed in draft standards as the technical requirements. The PPL Companies recommend that NERC, after considering industry comments and with Stakeholder approval, finalize its CEAP before deciding if the CEAP addresses the SPIG recommendation.
Response: Thank you for your comment. You identify many considerations that the CEAP must address. With industry support and involvement, the CEAP will be revised and a new draft will be posted for comment. The CEAP is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment		

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periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		
National Grid and Niagara Mohawk (A National Grid Company)		National Grid's understanding is that the CEAP document that was proposed is not intended for inclusion in the SMP and is not part of the currently proposed SPM revision, therefore is outside the scope of comments related to the SPM at this time.
Response: Thank you for your comment. Your separately submitted comments on the CEAP will be addressed in that Comment Report. The CEAP is not incorporated into the proposed revisions to the Standard Processes Manual. It is initially envisioned to be a Guideline document. In order to address the Standard Process Input Recommendation regarding the consideration of cost in the standard development process, it is proposed that additional questions regarding cost will be included in the posting of comment periods. This is intended to be an interim step until development of the CEAP is fully realized. It is NERC's intent to pilot the CEAP project to determine if any potential revisions need to be made. After successful pilot project(s) have been completed, the CEAP may be revised and an evaluation will be made as to whether and to what extent, the CEAP will need to be incorporated into the Standard Process Manual, the NERC Rules of Procedure, or other NERC documents (*e.g*. Standard Drafting Team Guidelines, etc.). A revised CEAP will be posted for a comment period and NERC will respond in writing to comments in the same manner as prescribed by the NERC Standard Processes Manual.		

6. If you have any other comments on these proposed revisions that you haven't already mentioned above, please provide them here:

Summary Consideration:

Organization	Yes or No	Question 6 Comment
Exelon Corporation		- RISC: The respective roles and responsibilities of the RISC and SC remain unclear. This is a critical component for stakeholders to understand before judging revisions to the SPM. - Section 4.2: For clarity, please consider delineating the drafting team in place at the SAR stage from the drafting team responsible for developing the reliability standard. These are distinctly different tasks in particular because often the SAR requester (either individual or team) participates in developing the draft SAR and in responding to comments on a posted draft SAR. As well, if current practice applies going forward, the Standards Committee can name a SAR comment review team when it approves a SAR for posting. That practice may be prudent in expediting the posting process; however, the SAR review team may not prove sufficiently diverse as a standard drafting team. It is not clear whether the SAR requester/sponsor can serve on the standard drafting team once a SAR is approved as a standard project. This should be clarified to stakeholders. - Section 7.0 – Interpretations: Greater clarity needed on the decision making process behind a potential Standards Committee decision to change a Request for Interpretation into a Standard revision

Organization	Yes or No	Question 6 Comment
		project. As currently proposed, the Standards Committee can reject a request for interpretation if the interpretation seeks to revise a standard, but the SC can also change the interpretation request into a standard revision. It is not clear how such decisions are made and what process transitions occur when a project changes from an Interpretation to a Standard revision. The request should be thoroughly discussed with requesters before a decision is made to change the path forward. The Interpretation requester should also be given the option of objecting to the conversion of an interpretation to a standard revision project and such an objection should be clearly noted in the SAR. In addition, as noted with SARs and Standards projects, it is not clear whether the Interpretation requester can serve on the interpretation drafting team. This should be clarified to stakeholders. If requesters are not to serve on the interpretation drafting team then the SC must emphasize communication with the requester to fully understand the rationale and technical concerns behind the interpretation request. - Section 16: Waiver Provision: Exelon agrees with the EEI comments. This provision is unnecessary and ill advised in its execution - Procedures: The proposed SPM references Standards Committee procedures. Please discuss the role of procedures, the procedure development process, how procedures approved and how procedures are communicated to stakeholders. - Section 4.8, page 20: The language contemplates changes in the individual representing the ballot pool entity, how will changes in the ballot pool entity status such as due to merger or acquisition be managed?

Organization	Yes or No	Question 6 Comment
		- Section 4.1, page 15: Please clarify what criteria determine the decision to remand or reject and whether the SC will post explanations for SAR rejection. - Section 3.7, page 11 The sentence suggests that there are only eight provinces in Canada when I believe it intends to reference only the eight covered by the NERC regions. I believe merely dropping the second "the" clarifies: "…the provincial governments of each of eight Canadian Provinces (Manitoba, Nova Scotia, Saskatchewan, Alberta, Ontario, British Columbia, New Brunswick and Quebec)…" - EEI comments: While referenced in response to some specific questions above, to the points not yet discussed, Exelon reiterates its agreement and support for the concerns raised in the EEI comments. Thank you for the opportunity to comment.
Response: Thank you for your comments. The Charter for the Reliability Issues Steering Committee, (RISC), is not under the purview of the Standards Committee and is not part of the standard development process. The draft charter and initial slate for the RISC was approved by the NERC BOT in August and the SC looks forward to clarifying the relationship between the SC and RISC. The Standards Committee (SC) acknowledges that there will be a necessary interface coordination to be implemented in order to assure effective coordination between the activities of the RISC and those of the SC. However, the Standards Committee has been charged with developing a set of revisions to implement SPIG recommendations 1, 4, and 5 and bringing the proposed revisions to the NERC Board of Trustees for approval in November 2012. Given this charge, the Standards Committee believes that it is appropriate to move forward with a set of changes now to implement as many improvements as possible, recognizing that some aspects of the process		

Organization	Yes or No	Question 6 Comment
		may need to be adjusted as experience is gained with RISC and with the new process. Regarding the delineation of drafting team composition in Section 4.2, there is no single best formula for drafting team composition that will suit every standard development project. Refraining from delineating a specific composition within the SPM provides flexibility necessary to allow a drafting team with the appropriate composition to be formed. To avoid a conflict of interest, NERC has adopted a practice of not allowing interpretation requesters to participate on the drafting team that prepares the interpretation, and will continue this practice, but does not believe it is necessary to include this information in the SPM. Regarding the right of a requester of an interpretation to determine how the request is to be processed, NERC staff does not agree that the requester has an explicit right to maintain control over every aspect of the request. By its nature, an interpretation is inefficient in that it requires all of the same processing steps as revision of a standard, but does not "fix" the underlying standard. A requester does not have a responsibility to make efficient use of industry resources, but NERC staff and the Standards Committee do have this responsibility and without the ability to make processing decisions, will not be able to fulfill the responsibility. Regarding clarification of criteria for remanding a SAR – this section of the SPM was not revised but it is anticipated that future revisions to the process will be required to, among other things, clarify the relative roles of the SC and the RISC. Please provide specific recommendations at that time. Regarding Canadian Provinces – thank you for the clarification. No other entity made this observation and it was not corrected in the revised draft of the SPM that was posted for comment. The change will be reviewed with NERC Legal to provide consistent language with other sections of the NERC Rules of Procedure. The Standards Committee Process Subcommittee has developed a number of detailed procedures which have been circulated for comment to the Process Subcommittee and Standards Committee prior to being approved by the Standards Committee. These procedures are posted on the NERC Standards website under "Resource Documents." Please see the response to EEI comments as well.
Texas Reliability Entity		(1) Why was "Additional Compliance Information" removed as a possible component of a Reliability Standard? (p. 10) That has been a legitimate and helpful component in the past.(2) Even with NERC's Quality Review process in place, there is still room for improvement in the quality of materials that are posted for ballot. We suggest that, under any revised process, the NERC-assigned facilitator/technical writer/project manager (may be more than one person) should be made clearly and

Organization	Yes or No	Question 6 Comment
		fully responsible for the QUALITY of the SDT's work product. This would include compliance with the SPM and other applicable guidelines, consistency (both internally and with other standards), and editorial quality (e.g., unambiguous language, logical organization, completeness, and few if any obvious errors in final documents). The SDT technical members should remain fully responsible for the technical content of the standard.
Response: Thank you for your comment. Additional Compliance Information is intended to be incorporated into the RSAW.		
ACES Power Marketing Standards Collaborators		-1- On p. 25 under "Form Ballot Pool" it says that "NERC Reliability Standards staff shall establish a ballot pool during the first 30 calendar days of the 45-day formal comment period. However, in the next paragraph it says that "Any member of the Registered Ballot Body may join or withdraw from the ballot pool until the ballot window opens," and in the next section under "Conduct Ballot" it says that "The ballot window shall take place during the last 10 calendar days of the 45-day formal comment period." This suggests that there is a 35-day period to join the ballot pool, which contradicts the previously mentioned 30-day period. This contradiction needs to be cleared up. Thank you for your comment. This is not a contradiction – a member of the Registered Ballot Body is allowed to withdraw from a ballot pool that they have joined as long as no ballot has started. A member of the Registered Ballot Body is required to join the ballot pool during the 30-day window that the ballot pool is open to be joined. So, for example, if a member of the RBB erroneously joins a ballot pool, they may contact NERC staff to be removed as long as balloting has not been initiated. The language in the SPM allows for this. -2- Towards the top of p. 6 it says "A quorum, which is established by at least 75% of the members of the ballot pool submitting a response with an affirmative vote, a negative vote, or an abstention." But down on p. 26 it says "A quorum, which is established by at least 75% of the members of the ballot pool submitting a response

Organization	Yes or No	Question 6 Comment
		excluding abstentions and non-responses." I believe that the statement from p. 6 needs to be edited as the statement on p. 26 was. Thank you. The method for calculating a quorum has been revised to include abstentions, consistent with the current SPM. -3- On p. 41 on the Process for Developing an Interpretation Diagram, Step 3, on the right side says that standards staff will form a ballot pool at this time. However, down in step 6 of the same diagram, on the left side, it says that the ballot pool will be formed during first 30 days of the formal comment period. This seems to be a contradiction that needs to be cleared up. Thank you. The diagrams will be corrected when the process revisions have been finalized. -4- On p. 32, under "Process for Developing a Defined Term," it says "Definitions shall not contain statements of performance Requirements." Since results-based standards involve three kinds of requirements, "performance" being one of them, this statement could be interpreted to mean that definitions cannot establish "performance" requirements, but can establish the other two kinds of requirements. Is this the intended meaning? If not, then it needs to be clearly stated that definitions cannot contain statements of any of the three types of standard requirements. The SC anticipates that additional revisions to the standards process will be required in the near future, including changes to address the relative roles and responsibilities of the SC and RISC, and changes to address your comment will be considered at that time.
Response: Thank you for your comments. See responses embedded above.		
National Grid and Niagara		1) Standards Drafting Team Composition: National Grid supports the changes to

Organization	Yes or No	Question 6 Comment
Mohawk (A National Grid Company)		Section 3.6 with regard to composition of drafting teams. However, National Grid believes that the standards drafting teams need better leadership in order to operate effectively, especially if quality review will be an ongoing process. National Grid recommends that this section be further revised to designate a project manager for each Standards Drafting Team with a defined role to: 1) ensure project deliverables and deadlines are met; 2) be responsible for oversight of the quality review process; 3) ensure the work of the team remains within the scope of the SAR. National Grid is not suggesting that a new position be created, but that a better-defined project manager function could be incorporated into either the role of the team chairperson or the team's NERC facilitator. With the addition of more non-technical experts to drafting teams, the project manager role might be better served by a non-technical member of the team. 2) Section 16 Waiver Provision: National Grid generally supports the concept of a waiver provision with appropriate controls/qualifications to ensure the provision is not abused. National Grid is concerned that the proposed Waiver provision, as drafted, is slightly too broad. The provision should require a clear demonstration of why the SPM process is inadequate in the circumstances where a waiver is permitted. National Grid suggests the following edits to the first two bullet points following "limited to the following circumstances": o Where the standards team demonstrates that the SPM process will not allow the team to meet regulatory deadlines set by FERC; o Where the standards team demonstrates that the SPM process will not allow the team to meet deadlines imposed by the NERC Board of Trustees; or. . .

Response: Thank you for your comments. Section 4.3 of the proposed revisions to the SPM addresses the addition of a project management function and other non-technical support to aid the drafting team in timely completion of its work.

The waiver provision was drafted by NERC Legal at the request of the Standards Committee leadership to address circumstances such as the failed PRC-005-2 recirculation ballot. It is not possible to identify in advance all of the circumstances nor what type of demonstration might be necessary; instead, the provision as drafted relies on a common-sense application and accountability to the

Organization	Yes or No	Question 6 Comment
NERC Board of Trustees as a means to appropriately limit its application. In all circumstances, if an entity feels that the process has been waived inappropriately, they may appeal the decision.		
Arizona Public Service Company		1. There appears to be typo error in the Sanction Table. Level 2 penalties start at $75,000. It should be $7,500 to be consistent. For example Level 3 penalties start with $ 15,000.2. There should be guidance on how the sanction table is applied, particularly where a large number of elements are involved. For example: for a maintenance violation, are the penalties based on per item or on the overall impact? In many instances impact is not proportional to number of violations. Another example would be time based violation. If an entity missed a requirement which has a small impact, the impact does not grow with time. Another example is the MVA size. A 20 MVA unit does not have the same impact on BES as a 1000 MVA unit. The sanction should be proportional to possible impact. There should be guidance with examples so that industry is clear on the intent of sanctions.3. The proposed Sanction Table does not contemplate a ZERO (0) or FFT type fine. This needs to be addressed before we can support the table.
Response: Thank you for your comments. Based on the majority of the comments received, the SCPS has re-examined the proposed revisions related to VRFs and VSLs, and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. If the Sanction Table concept moves forward at a future time, please provide comments on that proposal.		
Dominion		1. Page 10 of the SPM redline states the following:a. “The only mandatory and enforceable components of a Reliability Standard are the: (1) applicability, (2) Requirements, and the (3) effective dates. The additional components are included in the Reliability Standard for informational purposes, to establish the relevant scope and technical paradigm, and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.”b. Dominion supports the retaining the measures as

Organization	Yes or No	Question 6 Comment
		mandatory and enforceable components of the Reliability Standard and believes the RSAW should align with the Requirements and Measures of the standard. 2. The Standard Processes Manual (SPM) should address the creation of the Reliability ering Committee in Section 3.0. 3. Page 11 of the SPM redline provides conditions for disbanding of a drafting team by the Standards Committee. There is no guidance for the Standards Committee's disposition of the work should that option be exercised. Will another drafting team be appointed or will the project be canceled? 4. The SPM redline text boxes suggest that changes to Section 3.10 are intended to be responsive to SPIG Recommendation 4 by involving compliance staff in the development of RSAWs. Dominion supports the retaining the measures as mandatory and enforceable components of the Reliability Standard and believes the RSAW should align with the Requirements and Measures of the standard. 5. On page 21 of the SPM redline; there is a reference to "NERC's Benchmarks for Excellent Standards." A search on the NERC website failed to locate a document with that title; however, a document with a similar title was found. Please provide clarification as to the specific reference. 6. Step 4.4.2 requires the drafting team to document its justification for the Sanction Table references for each Requirement. Please explain where this justification will be documented. Will the Sanction Table reside in the SPM or in each individual Standard? 7. 8. Step 4.7 does not address the drafting team responding to comments during the formal comment period as described in the SCPS White Paper. 7. Step 4.11 describes the process for handling a negative ballot without comment or with a comment that is unrelated. This appears to be a cumbersome process and does not improve the efficiency of the standards development process (e.g., 30-days to notify the Standard Process Manager another 10 days for the balloter to respond

Organization	Yes or No	Question 6 Comment
		adds 40 days to the ballot process). 8. Step 6.2 in the second paragraph, suggest revising the second sentence to state "Compliance Monitoring and Enforcement Program staff." 9. Examples 3-8 in Section 7 need to be reworded to remove the additional "where" at the beginning of each example. 10. Section 13 states Reliability Standards approved by ANSI as American National Standards shall be reviewed at least once every five years. How is this approval designated on the Reliability Standard? 11. Section 2.5 Sanction Table Reference; Compliance Element is capitalized, this term is not included in Appendix 2 Definitions Used in the Rules of Procedure. Is this going to be a new proposed term?

Response:

1. Thank you for your comments concerning Measures and RSAWs. We believe this concern is alleviated by the process envisioned and the fact that the measures are not enforceable. The Commission has acknowledged that it is in NERC's discretion whether to provide Measures for the Requirements of a Reliability Standard. See e.g., Mandatory Reliability Standards for the Bulk-Power System, 118 FERC 61,218 at P 253 (2007)*("The Commission disagrees with commenters that a Reliability Standard cannot reasonably be enforced, or is otherwise not just and reasonable, solely because it does not include Measures and Levels of Non-Compliance. The Commission adopts the position it took in the NOPR that, while Measures and Levels of Non-Compliance provide useful guidance to the industry, compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement given the specific facts and circumstances of its use, ownership or operation of the Bulk-Power System. As we explained in the NOPR, and reiterate here: 'The most critical element of a Reliability Standard is the Requirements."*
2. The Charter for the Reliability Issues Steering Committee, (RISC), is not under the purview of the Standards Committee and is not part of the standard development process. The draft charter and initial slate for the RISC was approved by the NERC BOT in August and the SC looks forward to clarifying the relationship between the SC and RISC. The Standards Committee (SC) acknowledges that there will be a necessary interface coordination to be implemented in order to assure effective coordination

Organization	Yes or No	Question 6 Comment

between the activities of the RISC and those of the SC.

3. It is impossible to predetermine all of the circumstances that might arise and include the appropriate disposition of a drafting team's work for all of those circumstances. It is appropriate to leave flexibility to address the specific circumstances when this provision is exercised.
4. See response #1 above.
5. The appropriate title is ***Ten Benchmarks of an Excellent Reliability Standard***.
6. Based on the majority of the comments received, the SCPS has re-examined the proposed revisions related to VRFs and VSLs, and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM.
7.

To address your concerns regarding comments received during formal commenting periods and other stakeholder's comments regarding bundling of comments and providing responses back, the SPM drafting team is proposing the following new Sections 4.12 and 4.13 to replace the previous Sections 4.12 and 4.13 of the draft SPM:

4.12: Consideration of Comments

If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot.

There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot.

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		4.13: Additional Ballots A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted. 7. In response to comments concerning the time that would be added to the process in determining the "relevance" of comments associated with 'no' votes, the SCPS has modified its proposed revisions to the SPM so that no votes without comments would count toward quorum but would not count in the calculation of approval. 8. This language exists in the current SPM and was not revised. 9. Thank you for your comment. This cleanup edit will be made before the SPM is finalized for recirculation ballot. 10. To date, NERC has not filed any standard with ANSI as an American National Standard, nor has NERC completed a 5-year review of any standard. 11. See response #6 above.
Kansas City Power & Light		1. Section 2.5: Elements of a Reliability StandardOn page 9, the current proposal removes "Evidence Retention" as an element of a reliability standard. Thoughtful consideration of the data needed and a realistic expectation for the retention of different kinds of data to demonstrate compliance is an important element in the standards process. It will be an unreasonable expectation for smaller entities to store real time data sampled every few seconds for three or six years. Consideration for data retention should not be overlooked and it is recommended to retain "Evidence Retention" in standards development.In addition, the current proposal removes "Measures" as an element of a reliability standard. Descriptive measures are in harmony with performance based standards and provide the guidance necessary for entities and auditors to understand compliance expectations with the requirements. It is highly recommended the "Measures" element be retained in the standards process. Removal of the "Measures" will result in ambiguity and debate between entities, Regional Entities, and NERC regarding demonstrations of compliance.2.

Organization	Yes or No	Question 6 Comment
		Section 3.4: Standards CommitteeOn page 12 of the proposal, the first paragraph introduces the concept that the Standards Committee can dismiss a drafting team for a variety of failures of performance. This is considerable power to allow one Committee to hold. There is much in the way of judgment regarding the performance of a drafting team and their efforts and it is a serious matter to consider disbanding a drafting team and the disruption that will cause. It is recommended that the proposal be modified such that the Standards Committee should express standards team performance concerns and recommended actions to another NERC group, such as the Standards Oversight and Technology Committee, and allow the drafting team to defend itself to the NERC group to obtain consensus before actions are taken to disband a drafting team.3. Section 3.6: Drafting TeamsThe bullet points of items drafting teams should consider in the development of standards and requirements does not include Compliance Application Notices (CANs). Recommend these bulleted items include consideration of CANs in the development of new standards and requirements.
Response: The proposal is for Evidence Retention to be included as an element of the RSAW. Regarding Section 3.4, all aspects of the standards process, including this one, are subject to appeal if an entity believes the process has not been followed appropriately. The appeals process already included in the SPM allows for a second level of appeal to be addressed by the NERC Board of Trustees.		
Illinois Municipal Electric Agency		A factor in timely adoption of better reliability standards that doesn't seem to get mentioned very often is the amount of time to achieve regulatory approval. It is my understanding that FERC staff is now more involved in the actual STD standards development process, and that is encouraging. FERC should continue to be encouraged to not duplicate what has been statutorily delegagted to NERC once a proposed standard has been filed with FERC for approval. The self-regulatory process should be allowed to work. If a need is identified after a standard is approved, it can always be refined; i.e., give the standards product a chance to work. A reasonable time limit for regulatory approval action may be appropriate.Illinois Municipal Electric

Organization	Yes or No	Question 6 Comment
		Agency (IMEA) also supports comments submitted by Florida Municipal Power Agency.
Response: This is outside the control of NERC and the Standards Committee.		
Hydro One		a) The proposed SPM now contains provisions for the case when a ballot closes on a day which is a Saturday, Sunday or a federally-recognized United States holiday. We agree with the concept and believe it should be extended to all standards development activities, such as comment periods. Consideration must also be given to Canadian Holidays (national and those used in most Provinces).b) Section 16 is a new section giving the SC authority to "waiver" the process steps. More transparency is needed when a waiver is exercised and a justification process should be required.The concept of a waiver provision with appropriate controls/qualifications to ensure the provision must be used appropriately and with prudence. As drafted, it is too broad. The provision should require a clear demonstration of why the SPM process is inadequate in the circumstances where a waiver is permitted.Suggest the following edits to the first two bullet points following "limited to the following circumstances": o Where the standards team demonstrates that the SPM process will not allow the team to meet regulatory deadlines set by FERC; o Where the standards team demonstrates that the SPM process will not allow the team to meet deadlines imposed by the NERC Board of Trustees; or. . .c) A new paragraph in Section 4.18 proposes to give the SC additional authority to "withdraw" Standards, Interpretations, and Definitions for "good cause" once the Standards, Interpretations, or Definitions has already been approved by industry and the BOT. There appears to give NERC staff authority to discontinue to process Interpretations after the BB approves them. It states, "The NERC Reliability Standards andLegal staffs shall review the final Interpretation to determine whether it has met the requirements for a "valid" Interpretation. Based on this review, the NERC Reliability Standards and Legal staffs shall make a recommendation to the NERC Board of Trustees regarding adoption."d) Standards Drafting Team Composition: We support the changes to Section 3.6 with regard to composition of drafting teams. However,

Organization	Yes or No	Question 6 Comment
		we believe that the standards drafting teams need more defined leadership in order to operate effectively, especially if quality review will be an ongoing process. We recommends that this section be further revised to designate a project manager for each Standards Drafting Team with a defined role to: 1) ensure project deliverables and deadlines are met; 2) be responsible for oversight of the quality review process; 3) ensure the work of the team remains within the scope of the SAR. NPCC is not suggesting that a new position be created, but that a better-defined project manager function could be incorporated into either the role of the team chairperson or the team's NERC facilitator. With the addition of more non-technical experts to drafting teams, the project manager role might be better served by a non-technical member of the team.

Response: The SPCS believes that the current time requirements associated with the individual steps within the standard development process are necessary to minimize the time required for the development of standards. Extending the ballot window from 10 calendar days to 10 working days would be counter to the SPIG recommendations which are calling for improvements to shorten the process, as would adding additional holidays to the calendar of days when a ballot or other action cannot close.

The waiver provision was drafted by NERC Legal at the request of the Standards Committee leadership to address circumstances such as the failed PRC-005-2 recirculation ballot. It is not possible to identify in advance all of the circumstances nor what type of demonstration might be necessary; instead, the provision as drafted relies on a common-sense application and accountability to the NERC Board of Trustees as a means to appropriately limit its application. In all circumstances, if an entity feels that the process has been waived inappropriately, they may appeal the decision.

The new paragraph in Section 4.18 provides necessary flexibility to address events that cannot always be anticipated. For example, an urgent action project to develop a revision to BAL-004-0 to address Time Error Correction was recently determined not to be necessary for reliability and was withdrawn. This allows the SC to make prudent decisions. The express statement that NERC staff will make a recommendation to the Board of Trustees regarding adoption of interpretations is simply giving interpretations commensurate treatment with standards and codifying the process that is already followed. It is NERC staff's responsibility to make these recommendations.

Regarding drafting team composition, Section 4.3 of the proposed revisions to the SPM addresses the addition of a project management function and other non-technical support to aid the drafting team in timely completion of its work.

Organization	Yes or No	Question 6 Comment
American Transmission Company		A. ATC does not agree that Section 16.0, Waiver is needed and should be eliminated. It was not included as one of the SPIG Report recommendations. The waiver provision was drafted by NERC Legal at the request of the Standards Committee leadership to address circumstances such as the failed PRC-005-2 recirculation ballot. It is not possible to identify in advance all of the circumstances nor what type of demonstration might be necessary; instead, the provision as drafted relies on a common-sense application and accountability to the NERC Board of Trustees as a means to appropriately limit its application. In all circumstances, if an entity feels that the process has been waived inappropriately, they may appeal the decision. B. ATC is seeking clarification why the NERC Reliability Standards and Legal staff are reviewing the Request for Interpretation twice in Section 7.0 to determine whether it meets the requirements of as valid interpretation. It is done early in the request (3rd para.) and again near the end of Section 7.0 (2nd to last para.) of the redline copy. Please clarify. The early review is to determine whether the request qualifies as a valid request for interpretation; the latter review is of the interpretation itself, and is done by comparison with established criteria that an interpretation must meet. Also in Section 7.0, the redline eliminated all reference to "Quality Reviews" of Interpretation Requests including the footnote. ATC believes this must be included just as when drafting new or revised Standards. C. Section 10 Processes for Developing a Reliability Standard to a Confidential Issue (or Responsive to Non-Imminent Confidential Issue - Section 10.8) should both include "Quality Reviews" as part of the process, while abiding to the strict nature of confidentiality. All QRs are to be performed in parallel with the language development activities of the SDT and are to begin early in the process so that they don't have to be conducted at the end as a separate activity. D. General Comment: The SPM had several flowcharts, etc. that do not have labeling or reference to Figure numbers. ATC recommends that the SDT review the

Organization	Yes or No	Question 6 Comment
		flowcharts, etc. to make sure they are labeled properly. All charts will be finalized and labeled when the final process revisions have been approved. E. Section 13.0 Process for Conducting Periodic Reviews of Reliability Standards. ATC proposes there be a provision in this periodic review cycle that allows NERC to restart the five (5) or ten (10) year clock once the Standard has gone through a new version, since it was revised within the basic 5 or 10 year period. This would eliminate extra reviews of the Standard since the Standard was already reviewed as part of a previous Standards Development project. This is the intent, but further to this point, the revised SPM relieves NERC of the obligation to perform a ten-year review of a standard unless it has been filed with ANSI as an American National Standard. To date, NERC has not filed any of its standards as American National Standards. F. Possible clarification needed: In Section 4.3, there is no "legal" representative called out as part of the Standards Drafting Team as recommended by SPIG Work Group. (Is this considered Regulatory?) Yes. G. Section 2.2 Reliability Principles are referenced in the SPM as the foundation of Reliability Standards; however, these have not been "formally" defined. ATC recommends that the SDT consider adding this term to the NERC Glossary of Terms. Under the SPM, adding this term to the NERC Glossary requires a standard development project be initiated, with comment and ballot as per the SPM.
Response: Thank you for your comments. See responses embedded above.		
Public Service Enterprise Group		a. In section 3.5, the term "RSAW" is first used in the SPM (other than in text boxes) and should instead be replaced by: Reliability Standard Audit Worksheet

Organization	Yes or No	Question 6 Comment
		("RSAW"). The section has been revised. b. Section 4.5 has footnote 17 that states "The quality review will be conducted in accordance with the Standards Committee's approved procedure for conducting Quality Reviews." The footnote should provide a link to this procedure. Thank you for this suggestion. Once the procedure has been updated to reflect the process revisions, that might be an appropriate time to incorporate the link. Doing so now would be confusing because the current procedure is drafted to support the current SPM. c. Section 1.4 should have a new bullet added that's entitled "Communications Among RBB Members" that states "Registered Ballot Body members may use NERC e-mail "list serves" for their sector to exchange ideas and comments regarding a proposed standard at any time, including when the ballot window described in section 4.9 is open." This will encourage RBB discussion on issues impacting a standard. Thank you for the suggestion. Adopting this suggestion assumes that the only vehicle for such communications will be NERC listservs and it is inappropriate to tie the process to specific technologies. d. In Section 13, the term "American National Standards" should be defined. This is an ANSI term. We will consider adding a footnote to clarify the term if the process revisions are approved and go to a recirculation ballot. e. We strongly object to Section 16 - Waivers. We have several concerns: i. The objective of the SPM is to produce quality standards, and if any of the processes are waived, the result will be rushed and lower quality standards. The ability for the Standards Committee to waive, for good cause, "any of the provisions contained in this manual" is too broad and unconstrained. From a

Organization	Yes or No	Question 6 Comment
		stakeholder perspective, Section 16 completely eviscerates the other changes to the SPM and undermines stakeholder trust in the process. ii. For regulatory imposed deadlines, procedures and processes are in place in the ROP (Section 309.3) and the current SPM (expedited standards development process). Yet this expedited process section has been stricken in the proposed SPM changes. This deletion would be inconsistent with Section 309.3 which specifically references it. The expedited standards development process should be retained. If it does not adequately address the first two bullets in Section 16, then modifications to the expedited process should be proposed. iii. At a minimum, waivers to the SPM should be preceded by the following:a) The posting of an SC document to the RBB that describes the reason for the requested waiver, including the threat to reliability, and what processes would be changed by the waiver.b) A short (10 day) period for accepting RBB comments.c) After comments are received, the SC may either withdraw the waiver or request its expedited approval by the NERC board, ensuring that the board is supplied with the comments received. The waiver provision was drafted by NERC Legal at the request of the Standards Committee leadership to address circumstances such as the failed PRC-005-2 recirculation ballot. It is not possible to identify in advance all of the circumstances nor what type of demonstration might be necessary; instead, the provision as drafted relies on a common-sense application and accountability to the NERC Board of Trustees as a means to appropriately limit its application. In all circumstances, if an entity feels that the process has been waived inappropriately, they may appeal the decision. f. We suggest balloting all SARs, either through the RISC or the appropriate technical committee (OC, PC, or CIPC), to verify the initial need for a standard change. These are all stakeholder bodies with technical expertise. This process would ensure that reliability standards have passed a “reliability need” review before being processed by

Organization	Yes or No	Question 6 Comment
		the SC. The threshold for approval could be lower than the typical 2/3 approval (e.g., it could be a simple majority) to ensure that more SARs proceed to the SC for processing. This suggestion can more appropriately be addressed once the RISC is fully functioning.
Response: Thank you for your comments. See responses embedded above.		
Bonneville Power Administration		BPA has conducted a thorough review of all documents, during the review we have captured several questions and have made note of potential un-intended omissions or typos. Please review the following questions, comments or concerns. Regarding page 18 section 4.1, 2nd paragraph of the redlined Standards Process Manual: BPA believes the word "and" needs to be inserted between NERC Reliability Standard and Standards Committee. We believe this has been addressed – we were unable to locate an error. Regarding page 19, third bullet of the redlined Standards Process Manual: BPA was under the impression that the industry could appeal if the SAR was rejected. Where is the appeals process addressed? There is a single appeals process for any appeal of a process matter, including the handling of a SAR. One of the revisions that was made in the first posting was to streamline sections by moving all references of appeal to Section 8, which describes the appeal process. BPA appreciates the change made in section 4.9 of the redlined Standards Process Manual allowing the ballot to remain open until the next business day if the original closing date falls on a Saturday, Sunday or federal holiday. Thank you for your support. Regarding section 4.10 of the redlined version of the Standards Process Manual: BPA seeks clarification as to why abstain votes are no longer considered as part of the quorum. If they are not counted, what is the purpose of an abstain vote? The method for determining quorum has been corrected to include abstentions as the current SPM does.

Organization	Yes or No	Question 6 Comment
		Regarding Section 4.12 p. 28 of the redlined version of the Standards Process Manual: BPA seeks clarification regarding only responding to comments prior to the final ballot. BPA believes it would be more productive to be responding earlier in the process. The SPM drafting team points out that a draft standard will be improved incrementally as informal input is gathered and it is expected that the draft that will be posted for the formal posting and commenting/ballot will be a more robust draft that will reflect the input that has been obtained from the industry through the multiple informal forums. This is a significant change from the current practice of incremental improvement by successive formal comment periods and ballots and is intended to make more efficient use of drafting team and industry time and resources. Sections 4.12 and 4.13 have been revised to clarify the requirements to consider and respond to all written comments. The proposed new Sections 4.12 and 4.13 are as follows: **4.12 Consideration of Comments** If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot. There is no formal comment period concurrent with the Final Ballot and no

Organization	Yes or No	Question 6 Comment
		obligation for the drafting team to respond to any comments submitted during the Final Ballot. **4.13 Additional Ballots** A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted. However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted. Regarding Section 7.0, page 37 of the redlined version of the Standards Process Manual: BPA seeks clarification on whether or not an Interpretation can be provided for BOT approved standards that are not yet FERC approved. The section indicates that a request can be made for any standard that has been adopted by the NERC Board of Trustee's. The example given only references the current effective version and a version with a future effective date. Yes, an interpretation can be requested of any standard approved by the Board, regardless of its approval status at FERC, because standards may have different effective dates in Canadian provinces. The language in the SPM should work in either case. Regarding page 39 of the relined version of the Standards Process Manual: The second to the last paragraph appears to be out of order and should be moved to be the second sentence of the next paragraph. Suggesting "If approved by its ballot pool, the Interpretation shall be forwarded to the NERC Board of Trustee's for adoption. The NERC Reliability Standards and Legal staffs shall review the final Interpretation to determine whether it has met the requirements for valid interpretation. Based on this review, the NERC standards and legal staffs shall make a

Organization	Yes or No	Question 6 Comment
		recommendation to the NERC Board of Trustee's regarding adoption." Is the intent to have legal review prior to it being approved by the ballot pool or after? The legal review upon which the NERC staff recommendation to the Board would be based is conducted after the standard is approved by the ballot pool. This language reflects the current practice and was added to clarify that this is the practice. While we understand the suggestion to move the sentence, we believe it is also acceptable in the current location, and in the interest of focusing on the larger issues, have not moved it. P. 41 of the relined version of the Standards Process Manual: Conduct quality review/collect informal feedback - these steps do not appear to be referenced in the narrative section. BPA is in support of the standards being reviewed every 10 years. Thank you for your support. Regarding page 69, Section 16 "Waiver" of the relined version of the Standards Process Manual:BPA has concerns about Section 16, BPA understands the need to have the flexibility of a waiver. The waiver seems to be misunderstood. BPA is concerned that the waiver does not have a sunset period. BPA believes the waiver process should be used on an interim basis as temporary solution, and that NERC should start the NERC Standards Development process in parallel. BPA strongly believes that industry involvement creates the most efficient, effective and reliable standard. The waiver provision is not intended to limit industry involvement. NERC Legal does not believe a blanket sunset provision is necessary, because as drafted, each waiver of a process requirement would need to be reported to the NERC Board of Trustees, who could then determine on a case-by-case basis and in full consideration of the facts surrounding a particular use of a waiver, the best course of action. The waiver does not create an ongoing opportunity to waive the process for the entire development of a standard; instead, it provides flexibility to waive individual elements of the process when it is appropriate to do so for a limited set of circumstances. Regarding 'Cyber Security' Sanctions Table in the White Paper: The performance

Organization	Yes or No	Question 6 Comment
		based level two appears to have a typo. BPA believes this should be 7500 to 300000 ... not 75000 to 300000. Based on the majority of the comments received, the SCPS has re-examined the proposed revisions that would eliminate VRFs and VSLs and replace them with a "Sanction Table Reference" for each requirement, and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM.
Response: Thank you for your comments. Please see responses embedded above.		
Consumers Energy		Consumers Energy disagrees with the indication in the manual that, "The number of votes cast is the sum of affirmative and negative votes with related comments or stated objections, excluding abstentions, non-responses, negative votes without comments, and negative votes with unrelated comments." We believe that negative votes should count regardless of whether comments are submitted or not. This is especially important in light of the fact that currently, there is no allowance for submitting comments directly with the ballot. Without the ability to match comments to ballots, a number of negative ballots could be disregarded when determining whether a project has passed or not. Additionally, we are concerned that even if comments were submitted, they may be disregarded as unrelated. We would question who makes this determination and how industry could be assured that the ballots they cast are properly included.
Response: The revisions associated with the 'No vote" issue are in response to SPIG recommendations 1 & 5. It is the SCPS's intent to enhance the information provided to the Standard Drafting Teams ("SDT") with helpful and constructive input to allow the team to efficiently revise a standard during its development to meet industry concerns. In order to accomplish this, stakeholders need to be fully engaged early in the process and need to provide meaningful comments that are helpful and constructive, which will assist the SDT in developing revisions that are responsive to the concerns of the industry and establish an adequate level reliability. It has been demonstrated in the past that early engagement of stakeholders in the process produces higher quality standards in a shorter amount		

Organization	Yes or No	Question 6 Comment
of time. Based on the comments received, the SCPS has re-examined this issue and determined that the approach for evaluating the relevance of comments requires additional clarification and has eliminated the process for reviewing the relevance of comments from the proposed revisions. However, the SCPS has retained the concept of including 'No' ballots that are not accompanied by comments in the calculation of quorum but not being counted in the calculation of consensus. The SCPS believes stakeholders that vote 'No' without comment are not providing enough information to assist the SDT in revising the standard to reach consensus. This leads to inefficiency and prolongs the standards development process because the SDT is guessing at what the industry concerns are. With respect to NERC's balloting software - ultimately, NERC has a responsibility to provide tools to support whatever process is developed, and NERC staff will be prepared via software or manual methods if necessary, to ensure that balloters will be able to submit comments at each stage of the balloting process including initial, additional and final ballot, including an option to indicate support for another entity's comments without the need to submit full responses to every question.		
Duke Energy		Duke Energy also supports the addition of various resources (technical writers, legal and compliance experts) to the Standard Drafting Teams with authority over the technical content remaining with the industry technical experts. Changes to facilitate performance of quality reviews concurrent with the standard development will hopefully result in more well written standards in a more timely manner.
Response: Thank you for your comments and support.		
FirstEnergy Corp		FE has the following additional comments: 1. Section 1.4 - FE is curious about the reasons for the new section on Metric Policy? Does this mean there will be duplicate versions for U.S. and Canada/Mexico? The metric policy was added to the "Essential Attributes of NERC's Reliability Standards Processes to clarify the policy and make explicit the need to utilize measurements in standards that work in the context of an international ERO. The metric policy is intended to avoid having to develop multiple versions for the US, Canada, and Mexico.

Organization	Yes or No	Question 6 Comment
		2. Section 3.4 - FE supports the additional authority given to the SC to disband drafting teams for not producing results. This will help give the SC greater ability to facilitate the development of standards. Thank you for your support. 3. Section 3.7 - FE suggest the revisions consider adding a reference to Mexico. NERC Legal will consider making this change when specific agreements are in place with Mexican authorities. 4. Section 3.8 - In the new sentence "The Standards Committee may request that a NERC technical committee or other group prepare a Technical document to support development of a proposed Reliability Standard." It appears the word "technical" should not be capitalized. Thank you for identifying this typo. It will be corrected as a non-substantive change, along with other minor changes that have been identified by commenters, prior to recirculation ballot if the process revisions are approved by the ballot pool. 5. Section 3.10 - This section does not seem to address the comment box that appears next to it. There is no text describing the development of the RSAWs in the actual manual text. The section should be re-written to include some of the thoughts from the comment box and better clarify how RSAWs are developed. Although the intent is to have drafting teams work collaboratively with ERO compliance staff to develop RSAWs, Compliance staff are ultimately responsible for RSAWs and the Standard Processes Manual is not the appropriate location for explaining the process for developing RSAWs. The Standards Committee has been working with ERO Compliance to develop a procedure that will provide details of the process. When this is available, it will be publicly posted on the NERC website.
Response: Thank you for your comments. Please see responses embedded above.		

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Indiana Municipal Power Agency		Indiana Municipal Power Agency supports the comments submitted by Floriday Municipal Power Agency.
Response: See responses to comments from Florida Municipal Power Agency.		
ISO New England Inc.		InterpretationsWe have concerns with section 7.0. The section states an RFI should be rejected if (1) an issue can be addressed by an active standards development activity; (2) RFI request clarity on any items other than a Requirement; and (3) an RFI has already been addressed in the "record." First, the BOT has clarified that a valid RFI need not be limited to the Requirements in a Standard and that a RFI can take into account other parts of the Standard as well as materials that were developed in support of a Standard (i.e. whitepaper, technical guidelines, Q&A, etc.). Second, waiting for a standards development activity to create the requested Interpretation may not be an option, many projects take a year or more and then have to be filed and acted upon by appropriate governmental authorities. In the meantime, lack of a RFI may result in inappropriate enforcement action due to EAs determining their own Interpretation. Finally, it appears that the (2) and (3) completely contradict one another. By its nature, an interpretation is inefficient in that it requires all of the same processing steps as revision of a standard, but does not "fix" the underlying standard. A requester does not have a responsibility to make efficient use of industry resources, but NERC staff and the Standards Committee do have this responsibility and without the ability to make decisions about how to efficiently address a request, will not be able to fulfill the responsibility. Each case needs to be evaluated with the particular facts surrounding the request, and the inclusion of this information in the SPM is intended to clarify for all stakeholders what is the current practice. Compliance WaiversThere remains language allowing for "waivers" of enforceable requirements for field trial purposes. Since the enforceable requirements are essentially backed by law, perhaps NERC should request a policy statement from the

Organization	Yes or No	Question 6 Comment
		applicable governmental authorities that the authorities recognize NERC-approved waivers. This comment will be referred to the Compliance Monitoring and Enforcement program for consideration, but does not require a change to the SPM. WithdrawalsSection 4.18 proposes to give the SC additional authority to "withdraw" Standards, Interpretations, and Definitions for "good cause" once the Standards, Interpretations, or Definitions has already been approved by industry and the BOT. We have concerns with the lack of definition on what constitutes "good cause" and the underlying need that drove this change. This is problematic, given that as a minimum, both the Industry and the Board have previously approved the action. If this section is retained, there needs to be some due process around the withdrawal of an industry and Board approved action. As a minimum, there should be advance notice and opportunity for comment, with the results of the comments provided to the BOT. Interpretations We suggest the new paragraph in the Interpretation Section (7.0) be removed as staff makes recommendations for any standards action and this need not be in the SPM: "The NERC Reliability Standards and Legal staffs shall review the final Interpretation to determine whether it has met the requirements for a valid Interpretation. Based on this review, the NERC Reliability Standards and Legal staffs shall make a recommendation to the NERC Board of Trustees regarding adoption." We agree that NERC staff already make these recommendations as part of every standards action that is brought before the NERC Board, and inclusion of the language in the SPM is intended to clarify this. There needs to be some transparency with regard to rejected interpretation requests. There should be a public posting of rejected requests and the reasons for the rejection. This does not require an explicit change to the SPM, but your suggestion will be considered for future implementation. We disagree with the need for interpretation drafting teams to automatically create

Organization	Yes or No	Question 6 Comment
		SARs if they believe there is a reliability gap or if the drafting team says an interpretation can't be crafted. The industry should be asked if they agree with the drafting team's decision before any further effort is expended. The industry will have this opportunity when the SAR is posted for comment. This language is a direct implementation of the Board of Trustees' November 2009 guidance on interpretations. VariancesThe section on "variances" implies that a variance is needed for "a conflict with an approved tariff"; it is our understanding that where there is a conflict with existing tariffs or market rules, the tariffs take precedence. A variance is still required to make this explicit. Waived ActionsSection 16 will as a minimum, lead to a perception of abuse of the process. There needs to be transparency of each waived action. This would include public notice and an ongoing record of waived provisions. This will assist NERC and the industry in identifying underlying drivers that are causing delays and provide a safeguard to potential challenges on the legality of the standards. Introducing additional processing steps would defeat the intended purpose of having a waiver provision, which is to allow for the development of a standard to address a reliability need to take precedence over process requirements. Each waiver must be reported to the Board of Trustees, and the Board will have an opportunity to consider the facts surrounding each use of a waiver and direct that appropriate actions be taken. This sets a high bar that should discourage abuse of the waiver provision.
Response: Thank you for your comments. Please see responses embedded above.		
MEAG Power		MEAG Power endorses and adopts the votes and comments as provided by AECI.
Response: See response to comments submitted by AECI.		
NextEra Energy Inc		NextEra submits the following comments for consideration:

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		Sections 3.4 and 3.5 of the Standards Process Manual (SPM)The redlined SPM at page Section 3.4 reads in part:The Standards Committee may disband a drafting team if it determines (a) that the drafting team is not producing a standard in a timely manner; (b) the drafting team is not able to produce a standard that will achieve industry consensus; (c) the drafting team has not addressed the scope of the SAR; or (d) the drafting team has failed to fully address a regulatory directive or otherwise provided a responsive or equally efficient and effective alternative. NextEra suggests that the Standards Committee should have options other than disbanding the drafting team, such as adding members, in particular a facilitator and/or legal/technical writer. NextEra also believes that currently there are several structural issues that appear to cause drafting teams to be less than constructive at times, such as: (i) drafting teams insolate themselves or become reactive to such a degree that they are not responsive to stakeholder comments and (ii) drafting teams are not sufficiently coordinating with other drafting teams. The development of COM-002 and COM-003 appears are an example of a lack of coordination. To address these matters, NextEra suggests that Section 3.4 language above be revised to read: "The Standards Committee shall have the authority to at any time in the process: (a) to appoint a facilitator, legal or/and technical writer to a drafting team; (b) replace an ineffective facilitator, legal and/or technical writer; or (c) direct two or more drafting teams to consolidate efforts or coordinate with each other to reconcile any differences and produce consistent Reliability Standard requirements, white papers, etc. The Standards Committee shall also have the authority to disband a drafting team if it determines: (a) that the drafting team is not producing a standard in a timely manner; (b) the drafting team is not able to produce a standard that will achieve industry consensus; (c) the drafting team has not addressed the scope of the SAR or is producing work product outside the scope of the SAR; or (d) the drafting team has failed to satisfactorily or fully address a regulatory directive or otherwise provided a responsive or equally efficient and effective alternative." The language you reference in section 3.4 was added to make explicit that the SC has the authority to disband drafting teams; there is no presumption that this is the only

Organization	Yes or No	Question 6 Comment
		option available to the SC under the circumstances that are mentioned. The Standards Committee already does add new members to drafting teams, including to supplement the skills of the existing team (including facilitation or technical writing skills) or to provide additional leadership. On the two projects you mentioned, COM-002 and COM-003, the two drafting teams in question held a joint meeting in late 2010 and reported to the SC on the outcomes of that meeting. In short, although these changes are not inconsistent with the overall direction of the SPIG recommendations, it is not clear that the suggested language changes would, alone, result in different outcomes. Therefore, in order to focus the changes for the second draft on the substantive changes in hopes of getting support for those, we have not made the suggested changes and hope that you will continue to evaluate whether the changes are needed. Consistent with the above language changes, NextEra suggests that "facilitators" be added to the language in Section 3.5 that lists the members of a drafting team (to complement the additions of compliance and legal personnel), so that each drafting team is required to have a skilled facilitator. NextEra believes that many of the current issues associated with drafting teams result from a lack of structure and facilitation. A skilled facilitator will be able to provide a structure and direct discussions so that progress and decisions can be made in a much shorter timeframe, while at the same time providing a forum for all voices to be heard, including stakeholders and those individuals working on quality reviews. Without the addition of facilitators, NextEra is concerned that many of the current issues that hinder effective drafting teams will continue. We believe this is addressed in the last sentence of the first paragraph of Section 3.6, which reads: "The NERC Reliability Standards Staff shall provide, or solicit from the industry, essential support for each of the drafting teams in the form of technical writers, legal, compliance, and *rigorous and highly trained facilitation support personnel*." (emphasis added) Section 7 of the SPMNextEra also believes that Section 7 on interpretations needs language that outlines what is a valid interpretation request. Currently the new language states what an interpretation is not. NextEra recommends that Section 7

Organization	Yes or No	Question 6 Comment
		include the following statements: A valid interpretation request is a request that seeks clarification or an interpretation of a word, term or sentence(s) of a Reliability Standard requirement. When drafting an interpretation, if the plain language meaning of the word, term or sentence is not clear, the interpretation team may review the record of the standard drafting team that drafted the Reliability Standard, including interviewing members of the standard drafting team to ascertain the intent of the word, term or sentence(s) at issue. Thank you for this excellent suggestion. We believe this language is appropriate for inclusion in the Interpretation Drafting Team guideline, which will be revised for consideration by the Standards Committee Process Subcommittee and subsequent approval by the Standards Committee. The three new Sanction TablesNextEra believes that each of the new Sanction Tables need refinement. First, NextEra believes that level one for each table should start with a zero fine, not $3,000, $2,000 and $1,000 as currently written. NextEra is concerned that without the discretion to implement a zero fine for level 1 that it unduly constricts the discretion of NERC and the Regional Entities to impose zero fines, including fines under the Find, Fix, Track and Report mechanism. Also, NextEra is recommending that each of the levels be re-worded as follows so to consider multiple scenarios: The Operations Sanction Table (OST)Level 1 - a violation did not and would not be expected to adversely impact electrical state or capability of the BES or the ability to monitor or control the BES.Level 2 - a violation did not, but could have directly and adversely impact electrical state or capability of the BES or ability to monitor or control the BES, and the violations did not, but could have in an unlikely situation contributed to BES instability, separation, or a cascading sequence of failures.Level 3 - a violation did not, but under likely circumstances could have contributed to impeding restoration, damaging equipment or non-consequential load loss or could contribute to BES instability, separation, or a cascading sequence of failures.Level 4 - a violation did or could have very likely directly caused BES instability, separation, or a cascading sequence of failures. The Cyber Security Sanctions TableLevel 1 - a violation could adversely impact Low Impact BES Cyber Systems; but did not or would not be expected to expose the

Organization	Yes or No	Question 6 Comment
		electrical state or the capability of the BES; or the ability to effectively monitor and control the BES.Level 2 - a violation could adversely impact Medium Impact BES Cyber Systems; a violation could adversely expose the electrical state or the capability of the BES; or the ability to effectively monitor and control the BES. A violation of the requirement is unlikely to and did not lead to BES instability, separation, or cascading failures.Level 3 - a violation could adversely impact High Impact BES Cyber Systems; a violation did or could have impeded restoration, damaged equipment or non-consequential load loss or could have contributed to BES to instability, separation, or a cascading sequence of failures.Level 4 - a violation did or could have directly exposed the BES to instability, separation, or a cascading sequence of failures.Planning Sanctions TableLevel 1 - a violation did not and would not be expected to adversely affect the ability to assess the long-range reliability of the BES.Level 2 - a violation did not, but could directly and adversely affect the ability to assess the long-range reliability of the BES.Level 3 - a violation did or could contribute to development of a long-range plan that, if followed, could adversely affect the BES' ability to respond to contingencies.Level 4 - a violation did or could directly cause development of a long-range plan that, if followed, could adversely affect the BES' ability to respond to contingencies. Thank you for your thoughtful consideration of the proposed approach to replacing VRFs and VSLs with Sanction Table References. Based on the majority of the comments received, the SCPS has re-examined the proposed revisions and concluded that certain aspects of the proposal require additional clarification. Therefore the proposed revisions to eliminate the VRFs and VSLs have been removed from this draft of the proposed SPM revisions. The VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll will continue to be conducted per the SPM. The SCPS will continue to develop the concepts in response to the SPIG recommendations to ease the burden on the SDTs and to provide an opportunity to shorten the development timeframes associated with standard development projects. The SCPS will continue to work toward the elimination of the VRFs and the VSLs while further developing the concepts which will allow the ERO enterprise

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		(NERC, Regional Entities and stakeholders) to focus on the potential risk to the reliability of the BES and how to best manage that risk by developing quality results-based Reliability Standards, managing effective Risk-based Compliance Monitoring programs and enforcing standards based on comprehensive risk assessments.
Response: Thank you for your comments. Please see responses embedded above.		
SPP Standards Review Group		No.
Trans Bay Cable LLC		None
National Rural Electric Cooperative Association (NRECA)		NRECA has the following additional comments/questions that we request responses to before we can offer complete support for the draft SPM modifications: Has any analysis been completed to determine whether and to what extent these proposed SPM changes will actually shorten the time for developing a standard? Such analysis would be helpful in gaining a better understanding of the impact these proposed changes may have. Without implementing the changes, it is difficult to predict what the outcome of the changes will be. NRECA remains concerned about the lack of clarity related to the RISC proposal and its impact on the current and future role of the SC. Further clarity in this area is urgently needed so stakeholders can better understand the respective roles and responsibilities. The Charter for the Reliability Issues Steering Committee, (RISC), is not under the purview of the Standards Committee and is not part of the standard development process. The draft charter and initial slate for the RISC was approved by the NERC BOT in August and the SC looks forward to clarifying the relationship between the SC and RISC. The Standards Committee (SC) acknowledges that there will be a necessary interface coordination to be implemented in order to assure effective coordination

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		between the activities of the RISC and those of the SC. In the last paragraph of Section 2.5 of the proposed SPM under Application Guidelines, the relevant scope of a standard is stated to be informational only. NRECA believes this language is confusing and appears to state that the relevant scope of a standard is not part of the mandatory and enforceable component of a standard. The relevant scope of a standard should not be only an informational component of the standard. NRECA requests that this language be clarified such that the relevant scope of the standard is not something NERC can appear to be able to change as needed due to its informational-only status. The relevant scope of a standard should only be changed through the use of the standard development process. There is no specific "relevant scope" element of a standard. The scope a standard is determined by the Requirements and Applicability, which are developed as part of the standard development process. NRECA strongly disagrees that Section 3.4, items b and d are not appropriate reasons for the SC to disband a SDT. There may be many reasons why a SDT may not be able to achieve industry consensus or fully address a regulatory directive. We request that items b and d be deleted. Under the current SPM as well as the proposed revisions, Drafting teams report to the Standards Committee and are accountable for producing quality results in a timely manner. The Standards Committee must have the authority to hold drafting teams accountable and take actions that may be necessary to ensure that the ERO can fulfill its obligation to produce standards that address reliability issues, including in response to regulatory directives. The items that you are requesting be deleted are aimed at ensuring that the SC has the tools to fulfill its responsibilities. In Section 4.1, 2nd bullet on what the SC can do with a SAR, NRECA requests that this be revised to require the SC to provide an explanation of why the SAR is being remanded. In addition, in the 3rd bullet it is unclear what is meant by "good cause?"

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		Without further support, it appears the SC can reject a SAR for any reason as long as it provides a written response. NRECA believes this is too broad and that further context is required on the term "good cause." The Standards Committee is responsible for taking into consideration the impact on industry resources and needs to have the authority to take actions that are in the best interest of those resources while ensuring that the standards process produces quality standards that address reliability needs in a timely manner. In remanding a SAR for further work, it is anticipated that the Standards Committee would naturally discuss its reasoning and it is not necessary to place a requirement in the SPM to do so. With respect to reasons for rejecting a SAR, is impossible to anticipate and provide an exhaustive list of the possible reasons for rejecting a SAR. If an entity believes the SC has acted inappropriately, they may appeal the action. In Section 4.6 it is unclear to NRECA how QR will be done in parallel with standard development. Please provide additional direction in the SPM on how this is to be accomplished during standard development. Details about how QR is done are not included in the current SPM, and it is not appropriate to provide that level of detail in the proposed revisions. The details of how QR is conducted will change as experience is gained. In general, the concept of doing a QR in parallel with the development of a standard is to use the same principles that quality review volunteers now review for (as outlined in Background Information for Quality Reviewers), but have the trained legal and compliance volunteers work directly with the drafting team during the drafting of the Requirements and other elements of the standard. Also in Section 4.6, what is "criteria specified" and "specified criteria" referring to? The SPM does not clearly point to such criteria. Please see the document that is referenced (Ten Benchmarks of an Excellent Reliability Standard), posted at http://www.nerc.com/files/10_Benchmarks_of_Excellent_Reliability_Standards.pdf In Section 4.18 NERCA has a similar concern about what "good cause" means in this

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		context. Please provide further SPM language to better quantify this language. Currently it may be overly broad. Please see response above concerning the use of "good cause." In Section 4.19 NRECA believes this section should also reference the retirement of only a requirement, not only the entire standard. This section is intended to reference the retirement of an entire standard. Retirement of an individual Requirement is done through a revision of the standard, following the standard development process. In Section 7.0, item (2), NRECA does not understand why an interpretation can't be done for this reason. Please delete or provide further information to support his change. Also, in item (3), shouldn't this actually say that the interpretation work would be done by the active SDT, not that the RFI would be rejected?Also in Section 7.0, last two paragraphs of this section are confusing. It is not clear how the NERC reliability and legal staff review and the ballot results are coordinated in the process. Please clarify the roles of the staff review and the ballot results so that the SPM is clear on the respective roles. The reasons for rejecting an interpretation request are not limited to cases where an interpretation could not be developed; in some cases, the reason for rejecting the interpretation request is intended to provide the Standards Committee and NERC staff the ability to make responsible use of industry resources. In both item 2 and item 3, this is the case. Item 3 anticipates the case where a standard is being revised by an active team, and while the drafting team is working a Request for Interpretation of the prior version is submitted. In this case, it may be more efficient, depending on the status of the active project, to reject the interpretation request and direct the active team to address the issue in the revised version. The language that has been added about staff review at two different points (first of of the request, to ensure that it is a valid request, and second, of the interpretation that is approved by its ballot pool) have been included to make clear the process that is currently followed. NERC staff have an obligation to provide a recommendation to

Organization	Yes or No	Question 6 Comment
		the Board of Trustees on every standard action that is presented to the Board, including interpretations. NRECA is concerned by the deletion of the expedited process from the SPM. Please provide an explanation of why this helpful provision is being proposed for deletion. The addition of Section 16, the waiver provision, makes the expedited process unnecessary, since a standard can be expedited by exercising a waiver, which would then be reported to the Board. In Section 10.8 how and when will the pre-defined SMEs be determined? The NERC Critical Infrastructure Department maintains contact information for SMEs. NRECA does not support the addition of Section 16.0 to the SPM. We believe such authority is overly broad and we are not aware of any demonstration of need for such a broad waiver authority of any provision of the SPM. NRECA is also concerned that use of this waiver provision would appear to eliminate the need for the SC to report SPM violations to the CCC. While reporting use of the waiver provision to the BOT is helpful, the elimination of the checks and balances of having the CCC review such actions is troubling. Thank you for your comments.
Response: The Charter for the Reliability Issues Steering Committee, (RISC), is not under the purview of the Standards Committee and is not part of the standard development process. The draft charter and initial slate for the RISC was approved by the NERC BOT in August and the SC looks forward to clarifying the relationship between the SC and RISC. The Standards Committee (SC) acknowledges that there will be a necessary interface coordination to be implemented in order to assure effective coordination between the activities of the RISC and those of the SC.		
Northeast Power Coordinating Council		One item not included but needing further discussion is the comment forms beingprovided to the industry on all NERC activities. All the comments forms seem to bestated as “we made this change. Do you agree with this change?” An opportunity

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		forback-and-forth is not being provided to the industry with these types of comment forms.Who or what "body" should be approached with this issue. There should be more opportunities for open discussion with industry through the proper construction of questions on the comment forms. Thank you for your comments. If you have suggestions for constructing better questions on comment forms, please submit them to the NERC Director of Standards Development. Following are additional comments: 1. Section 16 is a new section giving the SC authority to "waiver" the processsteps. I do not support giving the SC this authority, thereby removing therequirement to report deviations of the process. I believe the SC already takes anexceptional amount of liberty with their "authority". More transparency is needed when a waiver is exercised and a justification process should be required.The concept of a waiver provision with appropriate controls/qualifications to ensure the provision must be used appropriately.The proposed Waiver provision, as drafted, is too broad. The provision should require a clear demonstration of why the SPM process is inadequate in the circumstances where a waiver is permitted. Suggest the following edits to the first two bullet points following "limited to the following circumstances": Where the standards team demonstrates that the SPM process will not allow the team to meet regulatory deadlines set by FERC; Where the standards team demonstrates that the SPM process will not allow the team to meet deadlines imposed by the NERC Board of Trustees; or. . . The idea of the waiver provision is to allow the standards process to be responsive to reliability needs by producing a quality standard in a timely manner. Adding additional process requirements is counter to this objective. As drafted, the waiver must be reported to the Board of Trustees, who will then be able to direct other actions as appropriate to the facts surrounding the particular waiver. 2. The section on "variances" implies that a variance is needed for "a conflict withan

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		approved tariff". Are Standards allowed to be developed under such scenarios? A standard may apply continent-wide, but in some instances conflict with a particular tariff. In this situation, a variance is appropriate. 3. NERC and the SC had taken the position that the BOT action had limitedInterpretations to the Requirements. However, upon further inquiry regarding theLevel 1 appeal for the NWPP FRI on BAL-002, the BOT instructed that theiraction had been too strictly interpreted and that their action did not limit thingscontained within the "four corners" of the Standard. However, even after this clarification, as I look through the SPM changes, there continues to be this egregious attempt to limit the Industry's ability to request an appropriate Interpretation and, therefore, stave off inappropriate enforcement. The specifics of this are in the Interpretation section, the SPM indicates that an RFI should be rejected if (1) an issue can be addressed by an active standardsdevelopment activity; (2) RFI request clarity on any items other than aRequirement; and (3) an RFI has already been addressed in the "record." I amnot supportive of these and actually believe that (2) and (3) completely contradictone another. The reasons for rejecting an interpretation request are not limited to cases where an interpretation could not be developed; and do not say a request *should* be rejected, but rather that it *may* be rejected. In some cases, the reason for rejecting the interpretation request is intended to provide the Standards Committee and NERC staff the ability to make responsible use of industry resources. In the case where a standard is being revised by an active team, and while that drafting team is working a Request for Interpretation of the prior version of the standard is submitted. In this case, it may be more efficient, depending on the status of the active project, to reject the interpretation request and direct the active team to address the issue in the revised version. The comment acknowledges that interpretations are sometimes requested to "stave off inappropriate enforcement." There are other vehicles for addressing this concern, and given the industry resources that are involved in drafting, balloting, and

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		commenting on each standard action, including interpretations, it is incumbent on NERC and the Standards Committee to ensure that those resources are not being used inappropriately. 4. There remains language allowing for "waivers" of enforceable requirements forfield trial purposes. Since the enforceable requirements are essentially backed bylaw, I question the SC and BOT authority to enact such "waivers." Thank you. This language has not been changed from the current, FERC-approved SPM. 5. Section 4.18 proposes to give the SC additional authority to "withdraw"Standards, Interpretations, Definitions for "good cause" once the Standards,Interpretations, or Definitions has already been approved by industry and theBOT. See item 1 above. It is impossible to anticipate when a previously-approved standard action may be overtaken by other events and no longer be required. This is not intended to undermine the industry's approval but rather to provide a reasonable way to manage the body of standards products. 6. Clarification is needed for quorum and approval calculations with examples given. The quorum calculation has been revised from the last draft to reflect the same approach to calculating a quorum as is used in the current SPM. A spreadsheet with approval calculation examples will be prepared and posted prior to the ballot of the SPM revisions. 7. Balloting: the Ballot Body has 10 CALENDAR days to vote; however, if a balloter votesNO without providing appropriate comments they will be contacted to enablethem to provide appropriate comments for their NO vote to count and they willhave 10 BUSINESS days. I think both should be business days. The intent of the

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		process revisions is to make the process more efficient, and adding additional days to the timeline by changing calendar days to business days is not consistent with this intent. When a standard is balloted, it has already been posted for 35 days prior to the ballot window and the act of balloting takes only a few minutes at most. It seems reasonable to assume that an individual who joins a ballot pool can either find those few minutes within a window of ten calendar days, or find time in the preceding 35 days to assign a proxy.. 8. The process of opening a solicitation every year seeking ideas for new StandardsDevelopment proposals should cease. We are already inundated withStandards Development activities and anyone can submit a SAR at any time. Thank you for this comment. 9. There is a new paragraph added to the Interpretation Section (7.0), thatappears to give NERC staff authority to continue to not process Interpretationsafter the BB approves them. It states, "The NERC Reliability Standards andLegal staffs shall review the final Interpretation to determine whether it has metthe requirements for a "valid" Interpretation. Based on this review, the NERCReliability Standards and Legal staffs shall make a recommendation to the NERC Board of Trustees regarding adoption." The language that has been added about staff review at two different points (first of of the request, to ensure that it is a valid request, and second, of the interpretation that is approved by its ballot pool) have been included to make clear the process that is currently followed. NERC staff have an obligation to provide a recommendation to the Board of Trustees on every standard action that is presented to the Board, including interpretations. 10. What Criteria constitutes a valid interpretation being used by NERC Standards and Legal Staff? NERC staff must abide by the criteria provided by the NERC Board of trustees at the November 2009 Board meeting. The Board resolution is available in

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		the minutes from that meeting. 11. Standards Drafting Team Composition: NPCC supports the changes to Section 3.6 with regard to composition of drafting teams. However, NPCC believes that the standards drafting teams need more defined leadership in order to operate effectively, especially if quality review will be an ongoing process. NPCC recommends that this section be further revised to designate a project manager for each Standards Drafting Team with a defined role to: 1) ensure project deliverables and deadlines are met; 2) be responsible for oversight of the quality review process; 3) ensure the work of the team remains within the scope of the SAR. NPCC is not suggesting that a new position be created, but that a better-defined project manager function could be incorporated into either the role of the team chairperson or the team's NERC facilitator. With the addition of more non-technical experts to drafting teams, the project manager role might be better served by a non-technical member of the team. Section 4.3 includes the following language: "The NERC Reliability Standards Staff shall provide one or more members as needed to support the team with facilitation, project management, regulatory and technical writing expertise and shall provide administrative support to the team, guiding the team through the steps in completing its project." This is intended to address the issues you have identified. 12. Ultimately an individual has the right to say a standard is not needed and that no amount of "tweaking" will make it acceptable. There has been no attempt to say otherwise.
Response: Thank you for your comments. Please see responses embedded above..		
IRC-SCR		Question 6 (Other Comments)InterpretationsWe have concerns with section 7.0 . The section states an RFI should be rejected if (1) an issue can be addressed by an active standards development activity; (2) RFI request clarity on any items other than a Requirement; and (3) an RFI has already been addressed in the "record." First, the BOT has clarified that a valid RFI need not be limited to the Requirements in a

Organization	Yes or No	Question 6 Comment
		Standard and that a RFI can take into account other parts of the Standard as well as materials that were developed in support of a Standard (i.e. whitepaper, technical guidelines, Q&A, etc.). Second, waiting for a standards development activity to create the requested Interpretation may not be an option, many projects take a year or more and then have to be filed and acted upon by appropriate governmental authorities. In the meantime, lack of a RFI may result in inappropriate enforcement action due to EAs determining their own Interpretation. Finally, it appears that the (2) and (3) completely contradict one another. We suggest the new paragraph in the Interpretation Section (7.0) be removed as staff makes recommendations for any standards action and this need not be in the SPM: "The NERC Reliability Standards and Legal staffs shall review the final Interpretation to determine whether it has met the requirements for a valid Interpretation. Based on this review, the NERC Reliability Standards and Legal staffs shall make a recommendation to the NERC Board of Trustees regarding adoption." By its nature, an interpretation is inefficient in that it requires all of the same processing steps as revision of a standard, but does not "fix" the underlying standard. A requester does not have a responsibility to make efficient use of industry resources, but NERC staff and the Standards Committee do have this responsibility and without the ability to make decisions about how to efficiently address a request, will not be able to fulfill the responsibility. Each case needs to be evaluated with the particular facts surrounding the request, and the inclusion of this information in the SPM is intended to clarify for all stakeholders what is the current practice. There needs to be some transparency with regard to rejected interpretation requests. There should be a public posting of rejected requests and the reasons for the rejection. NERC will consider implementing this suggestion in the future. We disagree with the need for interpretation drafting teams to automatically create SARs if they believe there is a reliability gap or if the drafting team says an interpretation can't be crafted. The industry should be asked if they agree with the

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		drafting team's decision before any further effort is expended. The industry will have this opportunity when the SAR is posted for comment. Compliance WaiversThere remains language allowing for "waivers" of enforceable requirements for field trial purposes. Since the enforceable requirements are essentially backed by law, perhaps NERC should request a policy statement from the applicable governmental authorities that the authorities recognize NERC-approved waivers. This language is unchanged from the current SPM, which has been approved by FERC. WithdrawalsSection 4.18 proposes to give the SC additional authority to "withdraw" Standards, Interpretations, and Definitions for "good cause" once the Standards, Interpretations, or Definitions has already been approved by industry and the BOT. We have concerns with the lack of definition on what constitutes "good cause" and the underlying need that drove this change. This is problematic, given that as a minimum, both the Industry and the Board have previously approved the action. If this section is retained, there needs to be some due process around the withdrawal of an industry and Board approved action. As a minimum, there should be advance notice and opportunity for comment, with the results of the comments provided to the BOT. It is impossible to anticipate when a previously-approved standard action may be overtaken by other events and no longer be required. This is not intended to undermine the industry's approval but rather to provide a reasonable way to manage the body of standards products. Disbanding Drafting TeamsRegarding section 3.4 (Standards Committee), there needs to be transparency and due process with regard to disbanding drafting teams. The drafting team should be able to make a written statement of the underlying causes of delay and present this to the SC before it is disbanded. With regard sub-bullet c under why a drafting team should be disbanded, a SAR only sets the maximum

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		bounds of a standard. The team need not address all aspects of a SAR if dictated by industry comments. There is no requirement that the SC disband a team; the section only provides the SC with the explicit authority to fulfill its obligations. Agree that a team need not address all aspects of a SAR; however, a determination must be made on a case-by-case basis whether the product produced by the drafting team fulfills the obligation of the team. For example, if the team has not addressed a regulatory directive assigned to the project or provided an "equally efficient and effective alternative," the team has not fulfilled its obligations. VariancesThe section on "variances" implies that a variance is needed for "a conflict with an approved tariff"; it is our understanding that where there is a conflict with existing tariffs or market rules, the tariffs take precedence. In this case, a variance would be required. Waived ActionsSection 16 will as a minimum, lead to a perception of abuse of the process. There needs to be transparency of each waived action. This would include public notice and an ongoing record of waived provisions. This will assist NERC and the industry in identifying underlying drivers that are causing delays and provide a safeguard to potential challenges on the legality of the standards. The idea of the waiver provision is to allow the standards process to be responsive to reliability needs by producing a quality standard in a timely manner. Adding additional process requirements is counter to this objective. As drafted, the waiver must be reported to the Board of Trustees, who will then be able to direct other actions as appropriate to the facts surrounding the particular waiver. This creates some transparency, and if the Board directs staff to keep a record of all waived provisions, staff will do so.
Response: Thank you for your comments. Please see responses embedded above.		

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Edison Electric Institute		Regarding proposed Section 16, the waiver proposal:EEI believes that this is unnecessary. Successful implementation of SPIG recommendations will eliminate need for waiver of any standards development process steps. As a general matter and to correctly align various responsibilities, EEI supports full ownership of the technical content of standards development projects by the various drafting teams and stakeholders through comments and balloting, and process oversight by NERC management. In comments to SPIG, EEI asked that the confusion over process oversight be resolved once and for all. NERC has the responsibility to deliver proposed standards to FERC and should have the tools to ensure timely responses.If problems develop that challenge timely project completion, drafting teams and NERC management need to efficiently resolve the matters. In addition, EEI envisions much stronger and more disciplined process oversight than has been practiced in some projects in the past, which should eliminate the problem. Instead of anticipating such a problem, EEI challenges NERC and all stakeholders to make strong commitments to develop and execute plans that define specific milestones and deadlines that ensure timely development. Waiving process steps for 'insubstantial' matters is a slippery slope that NERC should avoid. Moreover, there is case precedent that NERC has filed with FERC various 'minor modifications' that were not returned to the standards development process for balloting. The boundary for determining 'insubstantial' should be carefully considered and clarified from legal and regulatory perspectives before a final decision is made.
Response: Thank you for your comments. The waiver provision was drafted by NERC Legal at the request of the Standards Committee leadership to address circumstances such as the failed PRC-005-2 recirculation ballot. The current set of process revisions to address the SPIG recommendations, by themselves, will not prevent a similar situation unless a waiver provision is included in the SPM. The waiver provision is not intended to be used for insubstantial matters; indeed, setting a high bar for exercising a waiver by requiring the waiver to be reported to the Board of Trustees directly is intended to preclude frivolous exercise of this provision.		
ReliabilityFirst		ReliabilityFirst questions the removal of Time Horizons from section 2.5 of the Standards Processes Manual (SPM). ReliabilityFirst requests the justification of the

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		removal of Time Horizons. RFC notes that Time Horizons are still referenced in the Standard Processes Manual Revisions: SCPS White Papers for Background Information. Page 14 explicitly states: "... the SDT would write the requirement and then would simply identify the appropriate Time Horizon and the requirement type and category..."
Response: Under the proposed revisions, Time Horizons would be incorporated into the RSAW. This is appropriate because a Time Horizon is intended as one piece of guidance that is used to evaluate the seriousness of a violation of a Requirement.		
Florida Municipal Power Agency		Section 1.3, the redline of the second sentence seems to try to parallel Section 215 language. If that is the intent, then "reliability planning" ought to be deleted. These words were included in the current version of the SPM – this language was not changed. Under Section 2.15, on the sentence that has NERC management presenting the standard to the Board, should that include a statement about presenting dissenting opinions to the Board? Section 3.5 contains the following sentence, which seems to address your concern: "When presenting Reliability Standards-related documents to the NERC Board of Trustees for adoption or approval, the NERC Reliability Standards Staff shall report the results of the associated stakeholder ballot, including identification of unresolved stakeholder objections and an assessment of the document's practicality and enforceability." Is Section 4.17 accurately stated in consideration of Rule 321 of the ROP? Yes, NERC Legal believes it is. Section 4.19, second paragraph is missing one reference to Variances. This has been corrected. Section 7.0 disallows an interpretation on other enforceable portions of a standard, e.g., the effective date, Glossary of Term definitions (e.g., if a Term in the Glossary is ambiguouos). This is inappropriate. Interpretation requests should be allowed for any enforceable portion of a standard. If a definition is ambiguous, it needs to be revised

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		through the standard development process. Definitions are not interpreted in the same manner as standards.
Response: Thank you for your comments. Please see responses embedded above.		
Manitoba Hydro		Section 13.0 "Process for Conducting Periodic Reviews of Reliability Standards" - We disagree with the proposal to review standards every 10 years, from the previous five year requirement. Too much can change in ten years. It is just as important to review existing standards, to improve their quality and clarify, as it is to write new standards. A more regular standard review process would lead to a lower number of high-quality standards that are more beneficial to reliability. Section 16.0 "Waiver" - The ability to use a waiver is too broad. It states that a waiver can be used to address a time constrained regulatory directive, and most regulatory directives provide time constraints. A waiver should only be used for urgent reliability issues which pose a direct and significant risk to the Bulk Electric System, and not to fast-track directives.
Response: Thank you for your comments. All of the versions of the NERC standard process to date have had a 5-year review requirement, and the Standards Committee disagrees that the mere presence of a 5-year review requirement in the process will affect the number or quality of standards. As things change, other mechanism are in place to provide for a standard to be changed – any stakeholder can submit a Standard Authorization Request, a Suggestion form, or a request for interpretation (which may or may not lead directly to a revision of the standard, but could be used to apply an existing standard to a condition that was not anticipated when the standard was drafted). The Standards Committee understands your concerns about Section 16.0 but believes a waiver provision is essential to allow the flexibility in the process to ensure that we, as an industry can demonstrate the ability to act expeditiously when necessary for reliability. NERC's ability to respond to regulatory directives in a timely manner is a component of demonstrating this.		
Liberty Electric Power		Suggest modifying the criteria for passing a standard to consider a vote failed if less than 50% of a qualified segment casts affirmative ballots. This is especially important if the rules for counting negatives are going to change. As written, a segment could

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		reject a proposal unanimously but still see the measure pass if the remaining segments approve at a 75% rate.
Response: Thank you for your comments. If NERC is to maintain ANSI accreditation of its standard development process, the formula used to calculate the weighted segment approval of a ballot must not allow any single segment to cause a ballot to fail. Adoption of your proposed criterion is counter to this ANSI principle.		
SERC Planning Standards Subcommittee		The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: Thank you for your comments.		
Independent Electricity System Operator		The IESO has had concerns about the lack of an expedited process to address emergency standard approvals needed under special circumstances when, for example a reliability standard or interpretation is causing unintended consequences that could threaten the reliability of the bulk power system. In our opinion, the industry should grant authority in these circumstances to the NERC Board to act as quickly as needed and with only the amount of industry consultation that urgency allows. In other words, give the ability to act on good judgment to the NERC Board that is elected by the industry. NERC Reliability Standards Development Procedure makes provisions for urgent and emergency actions to be used when "a delay in implementing a proposed standard or revision can materially impact the reliability or security of the bulk power systems or is inconsistent with statutory or regulatory requirements for reliability standards, such as by causing adverse impacts on markets or undue discrimination." The IESO supports the Procedure by which the Standards Committee would have the accountability for determining if, in their judgment, an urgent action is necessary, but recommends that a distinction be made between "urgent" and "emergency" circumstances - with the NERC Board having the discretion to take emergency actions as discussed below.We believe that while this particular

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		section of the NERC Reliability Standards Development Procedure proposes a single provision to cover urgent and emergency reliability standard revisions, clear distinction and separation should be made between an urgent situation requiring an urgent standard development and an emergency situation requiring an immediate action. An emergency reliability standard revision procedural step would give the NERC Board the authority to act on its own motion to address an issue on an interim basis immediately, with a follow-on process to then review and address the issue on a more regular timetable.The current revisions to the Standard Processes Manual include the deletion of the "Expedited Standard Development Process" section and the introduction of a new section titled Section 16: Waiver. The revised version of Standard Processes Manual includes, in Section 16: Waiver, a course for the practical implementation of the urgent and emergency reliability standard revisions in a single process. As discussed above, the IESO believes that the proposed process should also establish an overriding authority on the part of the NERC Board to move immediately to address a reliability emergency.Accordingly, while we believe that the new section makes appropriate allowances for the Standards Committee to waive any of the provisions contained in the Standard Processes Manual for good cause and provide sufficient flexibility to the Standard Committee in administering the urgent standard development process, additional provisions are needed to implement the recommended authority under which the NERC Board would act to address emergency circumstances which present an immediate threat to reliability.
Response: Thank you for your comments. As you have accurately noted, the inclusion of Section 16.0, the proposed waiver provision of the SPM, negated the need for a separate "expedited" process. The Standards Committee believes that the NERC Board already has the authority to direct action to develop a standard in an emergency situation in which reliability is threatened, and therefore, a separate section of the SPM is not needed.		
MRO NSRF		The NSRF does not agree that Section 16.0, Waiver is needed and should be eliminated. It was not included as one of the SPIG Report recommendations. The waiver provision was added to provide flexibility that is lacking in the current

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		process to address unanticipated situations, and is arguably directly responsive to the overall efficiency goal of the SPIG recommendations. As proposed, all uses of a waiver would be reported to the NERC Board of Trustees, so the Standards Committee would not in any way have unilateral power but instead would be accountable to the Board for explaining its need to use a waiver. The Standards Committee understands your concerns about Section 16.0 but believes a waiver provision is essential to allow the flexibility in the process to ensure that we, as an industry, can demonstrate the ability to act expeditiously when necessary for reliability. NERC's ability to respond to regulatory directives in a timely manner is a component of demonstrating this Clarification is requested as to why the NERC Reliability Standards and Legal staff are reviewing the Request for Interpretation twice in Section 7.0 to determine whether it meets therequirements of as valid interpretation. It is done early in the request (3rd paragraph) and again near the end of Section 7.0 (2nd to last paragraph) of the redline copy. Both of the reviews that are included in the proposed revisions are reviews that happen under the current process, so the proposed revisions that include these reviews are simply intended to clarify the process for all stakeholders. The first review is conducted on the request for interpretation before it is accepted for processing; the second review is a review of the interpretation once it has been drafted and prior to being submitted to the NERC Board of Trustees for adoption. Section 10.1: Processes for Developing Reliability Standards Responsive to Imminent, Confidential Issues should include "Quality Reviews" as part of the process, while abiding to the strict nature of confidentiality. To coincide with these additions, the associated Process Steps in Figure 3 should be updated to reflect when the Quality Reviews are conducted. It is likely that a standard developed in response to an imminent confidential issue

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		would be developed with legal and compliance staff working directly with the drafting team in order to facilitate an expedited regulatory filing. For this and other reasons considering the unusual nature of the circumstances under which the NERC Board might be expected to direct that the confidential process be used, quality review was not incorporated into Section 10.1. In Section 4.3, there is no "legal" representative called out as part of the Standards Drafting Team as recommended by SPIG Work Group. This section appears to address your concern: **3.6: Drafting Teams** The Standards Committee shall appoint industry experts to drafting teams to work with stakeholders in developing and refining Standard Authorization Requests ("SARs"), Reliability Standards, definitions, and Variances. The NERC Reliability Standards Staff shall appoint drafting teams that develop Interpretations. The NERC Reliability Standards Staff shall provide, or solicit from the industry, essential support for each of the drafting teams in the form of technical writers, legal, compliance, and rigorous and highly trained facilitation support personnel. Section 2.2: Reliability Principles are referenced in the SPM as the foundation of Reliability Standards; however, these have not been "formally" defined. It is recommended that this term be added to the NERC Glossary of Terms. This suggestion would require initiating a standards development project. Section 13.0: Process for Conducting Periodic Reviews of Reliability Standards The NSRF proposes there be a provision in this periodic review cycle that allows the restart of the five (5) or ten (10) year clock once the Standard has gone through a new version, since it was revised within the basic 5 or 10 year period. This would eliminate extra reviews of the Standard since the Standard was already reviewed as part of a previous Standards Development project. This is the intent. The SPM should include a section that encourages the integration of internal controls

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		process proposed by NERC staff into the standards development process. Explicit direction that deficiencies noted in a process control requirement that are corrected under the required process are not a violation should be included. This is getting too specific about the content of a standard and is not appropriate for inclusion in the SPM. If the sanctions table is retained in lieu of the VRFs and VSLs it is suggested that an "administrative" or low risk column should be added to the sanctions table to distinguish between direct and indirect electric grid impacts. Organizations need policies, procedures, and evidence to be effective, but the presence or absence of these policies, procedures, and documentation doesn't directly impact the electrons flowing on the electric grid, nor does it mean that entities don't implement preventative actions such as testing relays. Therefore, the NSRF suggests an "administrative" column be added to align with the MRO's Performance and Risk Oversight Sub-committee Phase II efforts on developing internal controls and the classification of risk. Policies, procedures, and documentation play a role in being effective, but when categorizing direct BES risk of instability, uncontrolled separation and cascading, administrative issues (policies, procedures, and documentation) should be assigned to "low risk" and "administrative" category.Within the proposed Operations, Cyber Security and Planning "Sanctions Tables" there appears to be a typo in all of the Performance-based Level 2 violations. Rather than a monetary range of "$75,000 - $300,000" it seems like it should instead read as "$7,500 - $300,000". Based on the majority of comments received, indicating the need to further refine the concepts, the SCPS has decided to retain VRFs and VSLs and has abandoned the idea of replacing them with Sanction Table References at this time.
Response: Thank you for your comments. Please see responses embedded within your comments above.		
PPL Corporation NERC Registered Affiliated		The PPL Companies appreciate the Standards Committee's changes to address the SPIG Recommendations but have the following additional concerns about the change

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		in process.The PPL Companies are concerned with the addition of section 16 (waiver). Back-door powers can be abused, so normal processes should be adhered-to under all circumstances.The PPL Companies are also concerned that many parts of this proposal have already been used by NERC without modifying the process and getting FERC approval of new process. The discounting of negative votes is already apparent as is the disregard for providing specific responses to comments by replacing them with bundled generic responses that are not tied to a specific comment from a responsible entity. The elimination of the voting rights of stakeholders on VSL and VFR is also a modification that is replaced by a non-binding poll which gives NERC total freedom on that subject without a meaningful input from Stakeholders.The main goal of the proposed changes to the SPM is to make it faster - faster is not necessarily better. Quality products should be the goal - not just faster or a greater quantity of enforceable standards. The proposals to revise the SDP to reflect the minimum ANSI requirements seems inconsistent with NERC's efforts in promoting "best practices" among its members.

Response: Thank you for your comments. The waiver provision was added to provide flexibility that is lacking in the current process to address unanticipated situations. As proposed, all uses of a waiver would be reported to the NERC Board of Trustees, so the Standards Committee would not in any way have unilateral power but instead would be accountable to the Board for explaining its need to use a waiver.

Under the current SPM, all votes (negative, affirmative, and abstentions) must be counted. NERC has not, to date, made any changes to the formula by which votes are counted and is very concerned by the assertion that negative votes are already being "discounted." With respect to bundling comments and providing generic responses, in the past six years the volume of comments to which drafting teams must respond has grown from 40-50 pages per posting to what is commonly two hundred pages and sometimes more, with many of the comments repeating common themes. While reviewing comments is essential to provide drafting teams with the information needed to determine how best to modify their work to reach consensus, the task of providing individualized responses to every comment has consumed an increasing amount of valuable drafting team time. Many of the proposed process changes (including the proposal to replace VSLs) are designed to free up industry resources from process tasks that do little to enhance the quality of standards or improve reliability.

Under the current SPM, as well as the proposed draft, any stakeholder who feels that the process has not been followed may file an

Organization	Yes or No	Question 6 Comment
appeal.		
Occidental Energy Ventures Corp. (OEVC) and Electricity Consumers Resource Council (ELCON) together called Industrial Consumers		These comments relate to proposed revisions that have NOT been made but should be made. Industrial Consumers are quite concerned about the working relationship between the SC and the RISC. Industrial Consumers have submitted formal comments on the RISC Mandate and incorporate those comments by reference into these comments. The proposed revisions, in a text box, states: "As this recommendation is piloted [Section 4.1 - Standard Authorization Request], it is possible that some changes to the SAT process will be recommended but at this time no changes are proposed to the current process for handling SARs."Industrial Consumers agree that the RISC has not yet been formulated. However, Industrial Consumers believe that significant confusion, at best, may come from a process where some requests for NERC action on reliability issues and risks go through the RISC while others go directly to the SC. Industrial Consumers do not think that changes to the SPM should proceed unless and until this issue is resolved. We believe that this is a threshold issue.Specifically, Section #2 of the proposed RISC Mandate states: "The RISC is responsible for receiving reliability issues and risks from stakeholders, regulators, and the Board which meet the following criteria:" Industrial Consumers certainly agree with this statement - but it seems to bring some confusion. Specifically, some stakeholders feel that some SARs could (or should) be filed directly with the Standards Committee while other SARs, as well as other proposals for "reliability issues and risks," would go through the RISC. Industrial Consumers do not think that such a dual path is either desirable or workable. To resolve this potential problem, Industrial Consumers thus propose adding the word "all" between "receiving" and "reliability" in the RISC Mandate. The statement would then read: "The RISC is responsible for receiving all reliability issues and risks from stakeholders..." (Emphasis should NOT be in the actual document) Alternatively, if the word "all" is not added, Industrial Consumers strongly recommend that the RISC Mandate and the Standards Process Manual be modified to (a) explicitly define and describe the criteria that will be used to differentiate between those filings that go through the RISC and those that are filed directly with the Standards Committee and

Organization	Yes or No	Question 6 Comment
		(b) make specific changes to the Standards Process (including changes to the Standards Process Manual) that would allow the Standards Committee flexibility to reject, or alternatively refer proposals, that are filed with the Standards Committee when, upon a determination by the SC, are not good or complete candidates for standards development.Since such changes have not been proposed, Industrial Consumers recommend that the proposed revisions to the SPM not proceed at this time.
Response: Thank you for your comments. The Charter for the Reliability Issues Steering Committee, (RISC), is not under the purview of the Standards Committee and is not part of the standard development process. The draft charter and initial slate for the RISC was approved by the NERC BOT in August and the SC looks forward to clarifying the relationship between the SC and RISC. The Standards Committee (SC) acknowledges that there will be a necessary interface coordination to be implemented in order to assure effective coordination between the activities of the RISC and those of the SC. However, the Standards Committee has been charged with developing a set of revisions to implement SPIG recommendations 1, 4, and 5 and bringing the proposed revisions to the NERC Board of Trustees for approval in November 2012. Given this charge, the Standards Committee believes that it is appropriate to move forward with a set of changes now to implement as many improvements as possible, recognizing that some aspects of the process may need to be adjusted as experience is gained with RISC and with the new process.		
Ameren		We believe that in several instances, details are lacking. Of a primary significance, we are not sure which proposed process changes would eliminate items which currently require a Stakeholder approval. We would like to have an opportunity to carefully review and assess all such items prior to signing off on the proposed SPM changes.
Response: Thank you for your comments. The Standards Committee maintains a number of procedures that support the Standard Processes Manual, and the processes in the SPM have deliberately been written at a high level to provide flexibility to adjust details as lessons are learned in implementing the new processes. The enforceable elements of a standard will continue to be balloted for stakeholder approval under the new processes. The only item which is balloted as part of the standard in the current process but which is proposed to be handled differently in the new process is Measures. Under the new process, Measures in the standard would be replaced by information in the RSAW. Under the proposed process, the drafting team would participate in developing the		

Organization	Yes or No	Question 6 Comment
RSAW, which would be posted along with the standard during the final ballot, and a non-binding poll of the RSAW would be conducted. Please see the summary consideration under question 3 for additional information.		

END OF REPORT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Standard Process Manual Revisions to Implement SPIG Recommendations

Comment Period: November 21, 2012 – December 20, 2012
Successive Ballot: December 11, 2012 – December 20, 2012

Available Now

A 30-day comment period and successive ballot for the Standards Processes Manual Revisions is open through **8 p.m. Eastern on Thursday, December 20, 2012.**

Instructions

Members of the ballot pool associated with this project may log in and submit their vote by clicking here.

Please read carefully: All stakeholders with comments (both members of the ballot pool as well as other stakeholders, including groups such as trade associations and committees) must submit comments through the electronic comment form. During the ballot window, balloters who wish to submit comments with their ballot may no longer enter comments on the balloting screen, but may still enter the comments through the electronic comment form. Balloters who wish to express support for comments submitted by another entity or group will have an opportunity to enter that information and are not required to answer any other questions.

Next Steps

The Standards Committee Process Subcommittee subteams will review all comments received and determine what revisions are necessary to finalize the SPM. If no significant changes are made, the SPM will be posted for a recirculation ballot and, if approved by the stakeholder body, presented to the NERC Board of Trustees for approval.

Background

At its February 9, 2012 meeting, the NERC Board of Trustees (BOT) requested the assistance of the NERC Member Representatives Committee (MRC) to provide policy input, and a proposed framework, for specific improvements to the standards development process. The MRC Chair and Vice Chair invited several members of the MRC, two NERC BOT members, the NERC CEO, and the Standards Committee (SC) Chair – the group collectively known as the Standard Process Input Group (SPIG) – to join with them as participants in developing recommendations to improve the standards development process. Further detail on the SPIG recommendations is available in the posted SPIG report.

These recommendations were presented to the BOT and approved on May 9, 2012. The SC was specifically charged with addressing SPIG Recommendations 1, 4, and 5. The SC has organized this effort by leveraging each of its subcommittees, the Process Subcommittee (SCPS) and the Communications and Planning Subcommittee (SCCPS), to work in parallel on developing proposed revisions and conducting outreach to industry stakeholders to ensure that all interested stakeholders have an opportunity to provide their input.

An initial ballot of Draft 2 of the proposed revisions to the SPM concluded on October 12, 2012 and received a 63% approval. The SC, its subcommittees, and NERC staff continue to be grateful for the industry support and thoughtful comments on the improvements to the standard development process.

The SCPS and Standards Committee have reviewed all of the comments and made the following substantive changes in response to the comments:

- **VRFs, VSLs, Measures, and RSAWs** - The majority of the commenters recognize the burden that the development of VRFs and VSLs has on SDTs and support the development of potential alternatives. Commenters also expressed support for drafting team participation in developing RSAWs. Both of these items will require collaboration between the Standards Committee, NERC Standards staff, and NERC and Regional Compliance programs to develop and implement. Therefore the SCPS is continuing to work toward the elimination of the VRFs and the VSLs through the development of potential alternatives and is actively working with NERC and Regional Enforcement staff to establish a consensus on the concepts. In the same vein, NERC's Compliance program is working with Regions and stakeholders to develop and implement the Reliability Assurance Initiative (RAI), and as this effort evolves the SC and NERC Standards staff will leverage opportunities to align drafting teams and compliance staff to ensure that the intent of drafting teams is captured in approaches to monitoring compliance.

  While these concepts are further developed, Measures, VRFs and VSLs will continue to be drafted by the SDT and a non-binding poll of VRFs and VSLs will continue to be conducted consistent with current process.

- **Treatment of 'No' Votes During a Final Ballot -** Several commenters identified that during a Final ballot, there is no comment period. There is no obligation in the current SPM to accept comments during a recirculation ballot, and the proposed revisions to the SPM are consistent with the current SPM in that there is no comment period associated with a Final Ballot. Therefore, all 'no' votes submitted in a Final Ballot will count toward determination of both the quorum and consensus. Clarifying language and a new Footnote 24 have been inserted in section 4.11, to clarify this important point. Footnote 24 reads: *The Final Ballot is used to confirm consensus achieved during the Formal Comment and Ballot stage. Ballot Pool members*

voting negative on the Final Ballot will be deemed to have commented or supported the comments of other groups during prior Formal Comment periods.

- **Section 16.0 Waiver Provision** - In response to stakeholders concerns regarding transparency, openness and due process protections, the SCPS incorporated the concept of a notice period for stakeholders prior to consideration of a waiver request by the Standards Committee and clarified how notice to stakeholders will be provided when the waiver provision is exercised. We have also incorporated a provision for the immediate reporting of waivers by the Standards Committee to the Standards Oversight & Technology Committee.
- In addition, stakeholders identified a number of minor typographical errors and minor clarifications. These corrections have been made and are shown in the redline.

The SC, its subcommittees, and NERC staff are grateful for the industry participation and input to develop SPM revisions that result in efficient use of industry resources to develop high-quality results-based standards in a timely manner.

Additional documentation is available on the project page.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Revisions to the NERC SPM to Implement SPIG Recommendations Aug 2012_in
Ballot Period:	10/3/2012 - 10/12/2012
Ballot Type:	Initial
Total # Votes:	329
Total Ballot Pool:	376
Quorum:	**87.50 % The Quorum has been reached**
Weighted Segment Vote:	63.25 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	96	1	40	0.541	34	0.459	8	14
2 - Segment 2.	10	0.5	2	0.2	3	0.3	2	3
3 - Segment 3.	87	1	38	0.535	33	0.465	7	9
4 - Segment 4.	33	1	20	0.667	10	0.333	0	3
5 - Segment 5.	82	1	38	0.585	27	0.415	6	11
6 - Segment 6.	50	1	24	0.6	16	0.4	5	5
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.6	5	0.5	1	0.1	0	2
9 - Segment 9.	2	0.2	1	0.1	1	0.1	0	0
10 - Segment 10.	8	0.7	7	0.7	0	0	1	0
Totals	**376**	**7**	**175**	**4.428**	**125**	**2.572**	**29**	**47**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Negative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	

1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	
1	CPS Energy	Richard Castrejana	Negative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Transmission	Oliver A Burke		
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Nazra S Gladu	Negative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	National Grid USA	Michael Jones		
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White		
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Negative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Orlando Utilities Commission	Brad Chase		
1	PacifiCorp	Ryan Millard	Negative	
1	PECO Energy	Ronald Schloendorn		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	

1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Negative	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz		
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Negative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley		
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	
2	Midwest ISO, Inc.	Marie Knox	Negative	
2	New Brunswick System Operator	Alden Briggs	Negative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon		
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	
3	Central Lincoln PUD	Steve Alexanderson	Negative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Palo Alto	Eric R Scott	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	City of Ukiah	Colin Murphey		
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	
3	Consumers Energy	Richard Blumenstock	Negative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Negative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	

3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell		
3	Hydro One Networks, Inc.	David Kiguel	Negative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Negative	
3	Manitowoc Public Utilities	Thomas E Reed	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin		
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Oklahoma Gas and Electric Co.	Gary Clear	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Negative	
3	PacifiCorp	Dan Zollner	Negative	
3	Pepco Holdings, Inc.	Mark R Jones	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rutherford EMC	Thomas M Haire	Negative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alabama Municipal Electric Authority	Raymond Phillips	Negative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	American Public Power Association	Allen Mosher	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Negative	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	

4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	National Rural Electric Cooperative Association	Barry R. Lawson	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	South Mississippi Electric Power Association	Steven McElhaney	Negative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
4	WPPI Energy	Todd Komplin	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	City and County of San Francisco	Daniel Mason	Negative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng		
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Cowlitz County PUD	Bob Essex		
5	CPS Energy	Robert Stevens	Negative	
5	Detroit Edison Company	Christy Wicke	Negative	
5	Detroit Renewable Power	Marcus Ellis	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker		
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs	Affirmative	
5	Essential Power, LLC	Patrick Brown	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Negative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	

5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Negative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	PSEG Fossil LLC	Tim Kucey	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Negative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes		
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz		
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	WPPI Energy	Steven Leovy	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Negative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil		
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	

6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Daniel Prowse	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	North Carolina Municipal Power Agency #1	Matthew Schull	Abstain	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Kelly Cumiskey	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Negative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza		
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Ascendant Energy Services, LLC	Raymond Tran	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Abstain	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	

Legal and Privacy
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A New Jersey Nonprofit Corporation

NPCC, Inc.

AGENDA

Meeting No. 13
NPCC Governmental/Regulatory Affairs Advisory Group

Omni Mount Royal
1050 Sherbrooke Street West
Montreal, Quebec H3A 2R6

November 27, 2012 – 1:30 PM

Teleconference Information:
Call: (719) 785-1714
Code: 8093

Item	Description	Action	Est. Time
1.	Convene Meeting	Introductions – Carolyn O'Connor, Chair Anti-Trust Compliance Guidelines Roster Update	1:30 - 1:45
2.	Canadian Bulk Electric System Exception Process	Ontario – Barbara Constantinescu, IESO Quebec - Sylvain Clermont, Hydro-Quebec TransEnergie Maritimes – Alden Briggs, NBSO	1:45 – 2:30
3.	Updated NERC Reliability Impact of Environmental Regulations	Status – John Moura, NERC	2:30 – 3:00
4.	Electric Power Dependencies on Natural Gas	NERC Study Status John Moura, NERC	3:00 – 3:30
		Status of Multi-Regional Natural Gas Study Mark Babula, ISO-NE	3:30 – 4:00
5.	Regional Planning Updates	New York – John Buechler, NYISO New England – Anne George, ISO-NE Eastern Interconnection Planning Collaborative – John Buechler	4:00 – 4:50
6.	Next Meeting(s)	All	4: 50 – 5:00

From:	ben@benli.ca
To:	Guy V. Zito; david.kiguel@HydroOne.com; Lee R. Pedowicz; rscmembers; joelC@aesi-inc.com; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca; guyzito@yahoo.com
Subject:	RE: My SC Meeting notes
Date:	Friday, November 09, 2012 8:31:34 AM

Guy,

I can only speculate the reason behind your comment/response to Dave's note, that you assumed that since the SC appointed a SAR DT, it implied that the SC already accepted the Cold Weather SAR to launch a standard development project to address the issue.

That's not the case.

Below are some related but key points discussed on this subject not mentioned in Dave's note.

1. Appointing a SAR DT was deemed necessary to respond to comments on the SAR that's posted, regardless of whether or not a standard will be needed and despite the RISC's recommendation.
2. We haven't yet seen the industry comments so there is no presumption that a standard will or not be needed to address this issue.
3. The RISC recommendation is one view; the SC needs to look at views of the entire industry to determine if developing a standard is the right path.

Bottom line: no presumption on the need of the standard; the RISC's input is valuable, but does not trump the industry's majority view.

An interesting thought is: what happens if the views of the RISC and of the majority of the industry are miles apart?

I believe the SC needs to develop some kind of "criteria" to aid its decision making when it comes to proposed projects like this.

Ben

-----Original Message-----
From: Guy V. Zito [mailto:gzito@npcc.org]
Sent: Friday, November 09, 2012 7:38 AM
To: david.kiguel@HydroOne.com; Lee R. Pedowicz; rscmembers; joelC@aesi-inc.com; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca; guyzito@yahoo.com; ben@benli.ca
Subject: RE: My SC Meeting notes

Thank you for your notes David.

The Cold Weather Preparedness issue was addressed by the RISC at their first meeting. They directed the NERC Operating Committee to do the following;

* Develop some technical guidance in the form of a guideline.
* Develop some training
* Suggest something such as the old readiness audit to ensure the entities are taking action prior to the cold weather season.

I think it is inefficient to use industry resources to proceed down the standards path when the RISC has already stated that this is an issue to be

addressed by the Operating Committee and that a standard was NOT the appropriate course of action and the industry is not supportive a "standard" type solution to this risk.

Thanks,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor New York, NY 10018
212-840-1070
212-302-2782 fax

From: david.kiguel@HydroOne.com
Sent: Thursday, November 08, 2012 3:43 PM
To: Lee R. Pedowicz; rscmembers; joelC@aesi-inc.com; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca; guyzito@yahoo.com; ben@benli.ca
Subject: My SC Meeting notes

Hello all,

Please find attached my November 8 meeting notes.

David

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Draft Agenda
Standards Committee

November 8, 2012 | 1:00 p.m. – 5:00 p.m. ET

Phone Number: 1-866-740-1260
Meeting Code: 5247071
Security Code: 1234321

Introductions and Chair's Remarks

NERC Antitrust Compliance Guidelines *

Public Announcement *

SC Expectations *

Quorum obtained

Agenda

1. **Review of Agenda (Approve)**

   Approved with no changes

2. **Waiver of 5-day Rule (Approve)**

   Not needed

3. **Consent Agenda (Approve)**

   Items discussed separately

   - October 10-11, 2012 Standards Committee Meeting Minutes* **(Approve)**

   Approved.

   - Project 2013-01 Cold Weather Preparedness* **(Appoint** – Confidential**)**

     Issue of 3 out of 5 proposed are from TRE.
     Also, RISC directed OC to address issue.

     SAR DT appointments approved (2 abstentions):

   Edward G Schnell, American Electric Power

   Kevin Lynch, PSEG Power Fossil LLC

   Mike Gentry, Salt River

   Jason Fisher, Minnesota Power

JC Culberson, ERCOT (suggested Chair)

Matt Averett, Southern Company

- Project 2013-02 Paragraph 81* **(Appoint** – Confidential**)**

Appointed team was for the SAR phase.

Ken McIntyre (ERCOT) appointed to replace Sam Ciccone in the SAR team.

Also, same team will complete the phase 1 work.

Approved with no opposed or abstention votes.

4. **Projects under Active Development (Review)** (V. Agnew)

a. Status of Projects Under Active Development*

- *Project 2006-06 Reliability Coordination*

The industry approved IRO-002, IRO-005, and IRO-014 on July 25, 2011. The BoT approved the standards at the August 4, 2011 meeting. The BOT approved IRO-001-3 on August 16, 2012 and it will be included with the filing for the previously approved standards. The filing for the IRO standards will be made concurrently with the filing for the TOP standards approved under Project 2007-03 - Real-time Operations r0.

Currently, the two communication standards, COM-001-2 and COM-002-3 have been approved by industry stakeholders and are scheduled to be presented at the November 2012 BOT meeting.

The remaining standard for this project is IRO-003-2, which the drafting team tabled in early January 2012 to focus on moving the other standards forward. The Standards Committee raised a concern during the October meeting in Miami about this remaining standard. NERC staff will evaluate the next steps.

- *Project 2007-03: Real-time Operations r0*

NERC Legal is working on the draft petition which will be filed concurrently with Project 2006-06.

- *Project 2007-09 Generator Verification*

MOD-025, MOD-027 and PRC-019: The standards were posted for a 45-day formal comment period and concurrent initial ballot period from February 29 through April 16. The team met May 15-17 and developed responses to comments and revisions to the standards. The team worked with QR to respond to their comments and re-submitted the documents July 26. The posting schedule was determined during the August 9, 2012 SC meeting for this project. The standards were posted for a formal comment period and successive ballot, which ended on October 31, 2012.

MOD-026 and PRC-024: The standards were posted for a 30 day formal comment period and successive ballot between February 29th and March 29th. The team met May 15-17 and developed responses to comments and revisions to the standards. The team worked with QR to respond to their comments and re-submitted the documents July 26. The posting schedule was determined during the August 9, 2012 SC meeting for this project. The standards were posted for a formal comment period and successive ballot, which ended on October 31, 2012.

A coordination issue with RFC standards MOD-024 and MOD-025 is being addressed. RFC is withholding filing of their MOD -024 and MOD-025 standards until the continent-wide standard MOD-025 is approved. They will then evaluate whether the continent-wide standard meets their needs.

- *Project 2010-07: Generator Requirements at the Transmission Interface*

FAC-001-1 and PRC-004-2.1a were adopted by the BOT on February 9, 2012. PRC-005-1.1b and FAC-003-3 were adopted by the BOT on May 9, 2012. The legal petition, which incorporated all of the standards, was filed with FERC on July 30, 2012.

- *Project 2010-13.2 Generator Relay Loadability*

The standard was posted on October 5 which will facilitate the team meeting prior to Thanksgiving and working toward a formal posting through December with the initial ballot occurring after January 2, 2013. Although the project is currently 15 weeks behind its plan, the team has made substantive changes that would have most certainly been revealed by industry stakeholders resulting in an unnecessary schedule setback. The team is working diligently to compress the schedule as much as possible and will assess the feasibility of achieving the deadline following the initial ballot posting. Preemptively, the team has scheduled a follow up meeting for December should additional time be needed following the November meeting.

Team working to get back to schedule.

- *Project 2010-17 Definition of BES Phase 2*

Phase 2 is well underway. The Planning Committee is taking the lead on investigating threshold limits. The PC has been given a deadline of December 20, 2012 for the completion of its work.

FERC issued a NOPR on Phase 1 on June 21, 2012. Responses were filed on September 4, 2012.

The guidance document is posted for informal comment until November 5.

- *Project 2010-INT-01 Interpretation of TOP-006-2 for FMPP*

Scheduled for BOT adoption at the November 2012 meeting.

- *Project 2011-INT-01 Interpretation of MOD-028 for Florida Power & Light Company*

Rapid Revision Pilot. Approved at the February Board of Trustees meeting. Filed with FERC on 8/24/2012.

- *Project 2011-INT-02 Interpretation of VAR-002 for Constellation Power Gen*

This Interpretation Request was approved by the SC for Rapid Revision on Jan 12, 2012. The team held two conference calls the week of April 9-13 to discuss comments received and determine the next step for the standard. The team has completed developing responses to comments and made conforming revisions to the standard for QR on April 26. The documents were submitted to QR on April 30. The team received feedback from QR and made appropriate revisions to the documents and resubmitted them for posting on May 15.

The draft standard was posted for a 30-day successive ballot and comment period on May 22; and due to a technical issue the posting was extended to June 27. The standard achieved a quorum and passed the successive ballot.

The team held a conference call on July 2 to discuss the comments received on the ballot and prepare for the recirculation ballot. The team developed responses to comments and revised the VSLs for Requirement R2. The Consideration of Comments and revised standard were submitted July 9 for posting. The standard was posted for recirculation from July 18 to July 27 and received enough support to pass the ballot.

The proposed standard was presented to the NERC BOT at the August 16th meeting and approved. The project coordinator is working with NERC Legal on regulatory filing documents.

- *Project 2012-08.1 Glossary Updates Phase 1:Statutory Definitions*

The SAR for adding the definitions for Bulk Power System, Reliable Operation, and Reliability Standard to the Glossary of Terms Used in Reliability Standards was posted for a 45-day formal comment period from June 19 through August 2, 2012. An initial ballot was conducted July 24 through August 2, 2012.

The weighted sector vote for the initial ballot was 54%. Responses to the comments received are currently being developed. No timetable has been established for moving to a successive ballot.

- *Project 2013-02: Paragraph 81*

On October 25, 2012, the requirements being proposed for retirement (38 requirements in 27 standard versions) and an implementation plan were posted for a formal comment period and an initial ballot that will end on Monday, December 10, 2012 (the initial ballot will begin on Friday, November 30, 2012).

- *Project 2007-02 Operating Personnel Communication Protocols*

Draft 4 of COM-003-1 was submitted to Quality Review on October 26, 2012. The SDT will receive the results on Friday, November 2, 2012. A conference call to review the results is scheduled for November 5, 2012 to consider the QR team's recommendations and to prepare for posting draft 4. The OPCPSDT is estimating November 15, 2012 for posting draft 4.

- *Project 2007-06 System Protection Coordination*

The drafting team met at Ameren HQ in St. Louis October 16 -18, 2012. The team progressed in developing responses to comments and modifying the draft standard. Subteams are continuing to work on the draft standard and associated documents, conference calls will be held as needed. The team plans to have the 2nd draft of the standard posted for successive ballot the last week of November, 2012.

NOTE: The SC agreed the delay associated with the QR and results-based feedback is acceptable, but did not want to reforecast completion. The project will continue to be reported as behind schedule, with the understanding that this is an acceptable delay.

- *Project 2007-12 Frequency Response*

NERC filed for an extension of time to complete the proposed standard. FERC responded granting an extension of one year (filing deadline - May 31, 2013). NERC held two technical conferences on Frequency Response and collected technical comments and opinions on relevant issues. NERC filed a progress report at FERC on this standard on July 31, 2012. The SDT has prepared a third draft of the standard and associated documents for posting and a successive ballot. The draft standard and associated documents were posted for a 30-day comment period and successive ballot on October 5, 2012. The comment period and successive ballot is scheduled to end on November 5, 2012.

This project is being coordinated with Project 2010-14.1 Balancing Authority Reliability-Based Controls-Reserves for the BAL-012 standard.

- *Project 2007-17 Protection System Maintenance and Testing*

The recirculation ballot for PRC-005-2 – Protection System Maintenance concluded October 24, 2012 and the standard passed achieving a quorum of 81.08% and a weighted segment vote of 80.51%. The BOT write-up and initial FERC filing documents were prepared and sent to NERC management and legal staff.

NERC has initiated the process of gathering data pertinent to reclosing and auxiliary relays that is necessary to develop requirements for the maintenance of those relays. PRC-005 as well as the definition of Protection Systems will be revised over the course of the next few years in accordance with the timetables filed with FERC. Looking more closely at process here, PRC-005-2 progressed through the normal standards development process including four postings (all formal) for stakeholder comment over a 24 month period, beginning with an initial ballot in July 2009, and a failed recirculation ballot in June 2011. The Standards Committee authorized re-initiating the project with a posting of the SAR and revised standard (Draft 1) for a formal comment period and an initial ballot of the standard in August 2011. Draft 4 was posted for comment with a successive ballot in July/August 2012.

FERC issued Order 758 (February 3, 2012) approving a NERC Interpretation on PRC-005-1 and further directed NERC to include reclosing relays as well as auxiliary and non-electrical sensing relays (including sudden pressure relays).

•NERC believes it is on track to meet all outstanding directives associated with PRC-005, including those emanating from Order 758.

•NERC submitted two informational filings to FERC in response to Order 758.

•NERC drafted a SAR to add the maintenance and testing of reclosing relays in version PRC-005-3 which will begin immediately after PRC-005-2 is BOT approved.

•NERC submitted a schedule to include sudden pressure relays (used in taking transformers out of service) and other auxiliary relays in PRC-005-4 beginning in 2014.

- *Project 2008-06 Cyber Security Order 706*

Since completing a posting of the standards for a 30 day formal comment period and parallel successive ballot, which occurred from September 11, 2012, to October 10, 2012, the drafting

team considered all comments submitted and made clarifying and conforming changes. The SDT posted the standards for a 10-day recirculation ballot that ends on November 5, 2012.

- *Project 2009-01 Disturbance and Sabotage Reporting*

The standard was posted for a 30-day comment period and successive ballot which ended on May 24, 2012. The team met June 6-8 and began to respond to comments and revise the standard. The team conducted stakeholder outreach to help the standard achieve a successful ballot.

The team held an industry webinar July 30, 2012 and then a team meeting to finalize all documents for posting and successive ballot. The team submited the documents for QR on August 3, 2012 and receiverd the results on August 15th.

The team responded to the comments received from QR on August 23.

The standard was posted for successive ballot that ended on September 27th with a 63.40% approval rating. The team met October 4-5 to discuss the comments received and next steps. The team will proceed to recirculation ballot and held an industry webinar on October 22. The recirculation ballot began on October 24th and will be extended until November 5th due to issues arising from "Superstorm Sandy."

- *Project 2010-05.1 Phase 1 of Protection Systems Misoperations*

The drafting team met October 23-25, 2012 to continue developing their responses to comments. The team has scheduled two Ready Talk meetings and another face to face meeting in November with the goal of completing all documentation in December and posting for a successive ballot in January 2013. The team decided to adopt the internal controls concepts for this standard and the next posting of the standard will be as such.

- *Project 2010-14.1 Balancing Authority Reliabilitybased Controls – Reserves*

The four draft Standards were posted on June 4, 2012 for a 30 day formal comment period. The SDT is meeting on October 3 through October 5 to finalize the documents prior to posting. The project was delayed due to other higher priority project postings, but is now being expedited to coordinate with Project 2007-12 Frequency Response. The next posting is anticipated to begin in early November 2012.

b. Status of Outstanding Interpretations* *Recent updates only*

- *Project 2012-INT-05 CIP-002-3 for OGE*

Assigned to CIP IDT. A project team has been formed, and the team is has finished ts first formal comment period (30 day formal comment period was from June 27, 2012, to July 27, 2012). The IDT has reviewed comments, made changes as necessary in the interpretation, and is preparing to post the consideration of comments and the interpretation for formal comment and parrallel initial ballot.

The Request for Interpretation requests clarity on whether a company's SmartGrid Advanced Meter Infrastructure ("AMI") functionality, which may be able to disconnect more than 300 MW

of load, is considered a system or facility critical to automatic load shedding under a common control system capable of shedding 300 MW or more under CIP-002-3, Requirement 1.2.5.

- *Project 2012-INT-03 CIP-007 for TECO*

Interpretation requests clarification on CIP-007-3, Requirement R5. Specifically, the questions relate to the use of "technical and procedural controls" in Requirement R5, and whether each sub-requirement requires both technical and procedural controls. A project team from the Interpretation Drafting Team has begun drafting an interpretation and it expects to post for a first formal comment period in November 2012.

The IDT expects to post for first formal comment in Q4 2012.

- *Project 2009-22 Interpretation of COM-002-2 for the IRC*

The filing for the project 2009-22, COM-002-2a, R2 Interpretation will coincide with the filing of and project 2006-06, COM-002-3 and project 2007-02, COM-003-1. The target for filing will depend on the November 2012 and February 2013 BOT meeting results.

As of October 30, 2012 the status has not changed pending the filing of COM-003-1.

- *Project 2012-INT-02 TPL-003-0a & TPL-004-0 for SPCS*

The interpretation is posted for a 45-day formal comment period from October 22 to December 5 with an initial ballot will be conducted in the last 10 days of the comment period from November 26 to December 5. The team will respond to comments received from industry stakeholders in December and work toward its next posting in January 2013.

- *Project 2009-19 Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group*

Project restarted based on BOT Action re: the scope of this interpretation and the team's ability to rely on language other than solely the requirements. New chair Al DiCaprio assigned.

The interpretation was posted for comment and ballot. The ballot ended on September 4, 2012. The interpretation passed with an 87.78% approval rating. The SDT addressed comments received and a recirculation ballot has been posted (September 28 - October 8, 2012).

Scott Miller resigned as CIP Interpretations DT chair.

Difficult to obtain quorum for non-binding ballots.

c. Posting Projections Through December 2012*

To be posted during the week of November 5:

- *Project 2007-02, COM-003 (30-day comment period and successive ballot)*
- *Project 2010-14 BARC: BAL-012-1 only (45-day comment period and initial ballot)*
- *Project 2012-INT-05 Interpretation of CIP-002-3 for OGE (45-day comment period and initial ballot)*

To be posted during the week of November 12:

- *Project 2007-06, PRC-027 (30-day comment period and successive ballot)*
- *Project 2012-INT-04 Interpretation of CIP-007 for ITC (30-day comment period)*
- *Project 2012-INT-06 Interpretation of CIP-003 for Consumers Energy (30-day comment period)*
- *Standard Processes Manual Revisions (30-day comment period and successive ballot)*

To be posted during the week of November 19:

- *N/A*

To be posted during the week of November 26:

- *Project 2010-14 BARC: BAL-001-1, BAL-002-2, BAL-013-1 (45-day comment period and initial ballot)*

To be posted during the week of December 3:

- *Project 2007-12 Frequency Response (possible recirculation ballot)*

To be posted during the week of December 10:

- *Project 2010-17 DBES Phase 2 (45-day comment period and initial ballot)*
- *Project 2007-09 Generator Verification (possible recirculation ballot)*
- *Project 2010-13.2 Generator Relay Loadability, PRC (45-day comment period and initial ballot)*
- *Project 2010-11, TPL FN "b" (possible recirculation ballot)*

To be posted during the week of December 17:

- *Project 2010-11, TPL FN "b" (possible recirculation ballot)*
- *Project 2013-02 P81 (possible recirculation ballot)*
- *Project 2010-05.1 PRC-004 (45-day comment period and initial ballot)*

To be posted during the week of December 24:

- *N/A*

To be posted during the week of December 31:

- *N/A*

Project	10/29	11/5	11/12	11/19	11/26	12/3	12/10	12/17	12/24	12/31
Project 2010-11 TPL FN 'b'										
Project 2013-02 P. 81										
Project 2007-02 – COM-003										
SPM Revisions										
Project 2007-12 Frequency Resp.										
VRF/VSL Revisions										
Project 2008-08 (10 CIP Standards)										

Project 2008-08 (10 CIP Standards)										
Project 2008-08 (10 CIP Standards)										
Project 2008-08 (10 CIP Standards)										
Project 2008-08 (10 CIP Standards)										
Project 2008-08 (10 CIP Standards)										
Project 2008-08 (10 CIP Standards)										
Project 2008-08 (10 CIP Standards)										
Project 2008-08 (10 CIP Standards)										
Project 2008-08 (10 CIP Standards)										
Project 2010-17 DBES Guidance Doc										
Project 2009-01 CIP-001 and EOP-004										
Project 2010-17 DBES Phase 2										
Project 2007-09 Generator Verification										
Project 2007-09 Generator Verification										
Project 2007-09 Generator Verification										
Project 2007-09 Generator Verification										
Project 2007-09 Generator Verification										
Project 2007-06 PRC-027										
Project 2010-05.1 PRC-004										
Project 2010-14 BARC										
Project 2010-14 BARC										
Project 2010-14 BARC										
Project 2010-14 BARC										
Project 2010-13.2 Gen Relay Load. PRC										
Project 2012-INT-02										
Project 2012-INT-04 CIP-007 Interpretation										
Project 2012-INT-05 CIP-002-3 Interpretation										
Project 2012-INT-06 CIP-003 Interpretation										
Number of Standards Posted	17	6	10	9	12	11	13	14	8	6

	Projected for November NERC Board of Trustees meeting
	Projected for December BOT
	Projected for Feb BOT
	Projected for May BOT
	Draft SAR
	30-day comment period
	45-day comment period and initial ballot
	30-day comment period and successive ballot
	Possible recirculation ballot depending on previous ballot results

5. Actions

a. NERC Standards Process Manual revisions* **(Authorize** – to be sent separately**)**

Not ready yet. Asking to take to SCEC.

b. Standards Authorization Request to revise CIP-001-2a* (L. Hussey) **(Accept, Reject, or Remand)**

Requirement R4 in the currently effective version 2a of the standard requires that each RC, BA, TOP, GOP and LSE establish communications contact, as applicable, with the FBI and RCMP.

As written, the requirement does not reflect current sabotage reporting and investigation protocols in the different Canadian Provinces.

It is proposed to modify the standard so that Requirement R4 considers the current or future arrangements for sabotage reporting and investigation in different jurisdictions.

Withdrawn given the approval of the new standard by the BoT. No need to modify the CIP-001-2a any more.

6. Discussion Items

a. Strategic Direction for NERC Standards Program (M. Lauby)

b. Report on MRC, BOT, and BOT SOTC Meetings (A. Mosher and M. Lauby)

Work on changes requested to the SC. Plan is to present for approval at the February 2013 BoT meeting.

c. Update on CEAP Pilot (L. Hussey)

Identification of projects to pilot waiting for final standards plan for next year.

d. Subcommittee Reports

1. Communication and Planning Subcommittee (A. Brown)

Still working on projects.

Workshop was successful (180 presnt and ~60 through webinar)

2. Process Subcommittee (B. Li and L. Campbell)

Nothing to report.

Still working on SPM changes.

e. Schedule and Locations for 2013 Meetings* (K. Iwanechko)

Schedule considers aligning with standing committee meetings.

- *January 16-17, 2013 – Atlanta (8-5 p.m. January 16; 8-3 p.m. January 17)*
- *February 2013 – no conference call*
- *March 7-8, 2013 – Albuquerque (8-5 p.m. March 7; 8-3 p.m. March 8) with PC/OC*
- *April 4, 2013 conference call from 1-5 p.m.*
- *May 2, 2013 conference call from 1-5 p.m.*
- *June 5-6, 2013 – Atlanta (8-5 p.m. June 5; 8-3 p.m. June 6)*
- *July 18, 2013 conference call from 1-5 p.m.*
- *August 15, 2013 conference call from 1-5 p.m. Conflict with BoT. Reschedule.*

• September 19-20, 2013 – Denver (8-5 p.m. September 19; 8-3 p.m. September 20) with PC/OC

• October 17, 2013 conference call from 1-5 p.m.

• November 14, 2013 conference call from 1-5 p.m.

• December 12-13, 2013 – Atlanta (8-5 p.m. December 12; 8-3 p.m. December 13)

The Standards Committee has two subcommittees (Communications and Planning Subcommittee and Process Subcommittee) and these subcommittees typically meet on the day immediately preceding the Standards Committee's face-to-face meetings. For 2013, these dates are:

• January 15, 2013 in Atlanta

• March 6, 2013 in Albuquerque

• June 4, 2013 in Atlanta

• September 18, 2013 in Denver

• December 11, 2013 in Atlanta

7. Coordination (Review) (S. Tyrewala)

a. Coordination with Regulatory and Governmental Authorities

b. Upcoming Standards Filings

Some filings are due in November/December and January.
FERC filing comments to the FERC NOPR on GMD.

8. Informational Items (Review)

a. NERC Drafting Team Vacancies*

- *Project 2007-12 Frequency Response*

Seeking individual representing Transmission Dependent Utilities (TDU) with experience in analyzing or modeling frequency response.

- *Project 2007-06 System Protection Coordination*

Seeking an individual from a Canadian entity with experience in coordination of Protection Systems (new installations and revisions).

b. Standards Committee Roster*

c. Highlights of Parliamentary Procedure*

9. Executive Committee Actions (Pre-authorize)

Request: To approve posting of the SPM for another 30-day comment period and ballot.

SC members will receive material at least 3 days prior to the SCEC call and send any comments to SCEC members.

Approved with no apposed or abstentions.

10. Adjourn

*Background materials included.

From:	Guy V. Zito
To:	david.kiguel@HydroOne.com; Lee R. Pedowicz; rscmembers; joelC@aesi-inc.com; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca; guyzito@yahoo.com; ben@benli.ca
Subject:	RE: My SC Meeting notes
Date:	Friday, November 09, 2012 7:38:18 AM

Thank you for your notes David.

The Cold Weather Preparedness issue was addressed by the RISC at their first meeting. They directed the NERC Operating Committee to do the following;

- Develop some technical guidance in the form of a guideline.
- Develop some training
- Suggest something such as the old readiness audit to ensure the entities are taking action prior to the cold weather season.

I think it is inefficient to use industry resources to proceed down the standards path when the RISC has already stated that this is an issue to be addressed by the Operating Committee and that a standard was NOT the appropriate course of action and the industry is not supportive a "standard" type solution to this risk.

Thanks,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: david.kiguel@HydroOne.com
Sent: Thursday, November 08, 2012 3:43 PM
To: Lee R. Pedowicz; rscmembers; joelC@aesi-inc.com; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca; guyzito@yahoo.com; ben@benli.ca
Subject: My SC Meeting notes

Hello all,

Please find attached my November 8 meeting notes.

David

From: Guy V. Zito
To: rscmembers; rsc
Cc: jcastle@nyiso.com; amosher@publicpower.org
Subject: FW: NERC DOCUMENT POSTED: Reliability Issues Nomination Form
Date: Tuesday, November 20, 2012 10:02:33 AM

RSC Members,

See below. If there are any issues you would like to raise with the RISC please do so and also let me know. There is a RISC meeting scheduled for December 17th which I plan to attend and I will serve as the NPCC regional contact to the RISC for any reliablity risks we wish to raise. I will have this on the agenda for our Montreal meeting of the Regional Standards Committee.

Thanks,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: Michelle Marx [Michelle.Marx@nerc.net]
Sent: Monday, November 19, 2012 9:00 AM
To: michelle.marx@nerc.net
Subject: NERC DOCUMENT POSTED: Reliability Issues Nomination Form

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Nomination Deadline

Reliability Issues Nomination Form

November 19, 2012

The Reliability Issues Steering Committee (RISC) is accepting nominations for consideration at its December 17, 2012 meeting. Please submit any nominations for this meeting on or before November 30, 2012. Any nominations received after this date will be considered at a subsequent meeting.

NERC bases its operations on four pillars: Reliability, Assurance, Learning , and Risk-based Approach. In support of making risk-informed decisions and enabling prioritization of issues, please use this form to submit potential issues (with as much supporting information as you can provide) for consideration by the RISC. Supported by NERC staff, the RISC will work with the industry to help develop overall ERO strategy by identifying and prioritizing the most important reliability issues facing our industry and properly aligning resources to address them. By providing this information, you are helping to ensure the ERO is focusing on the correct priorities as it moves forward.

Click Here for: Nomination Form

For more information or assistance, please contact Andy Rodriquez.

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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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From: Michelle Marx
To: michelle.marx@nerc.net
Subject: NERC DOCUMENT POSTED: Reliability Issues Nomination Form
Date: Monday, November 19, 2012 9:22:11 AM

Nomination Deadline

Reliability Issues Nomination Form

November 19, 2012

The Reliability Issues Steering Committee (RISC) is accepting nominations for consideration at its December 17, 2012 meeting. Please submit any nominations for this meeting on or before November 30, 2012. Any nominations received after this date will be considered at a subsequent meeting.

NERC bases its operations on four pillars: Reliability, Assurance, Learning , and Risk-based Approach. In support of making risk-informed decisions and enabling prioritization of issues, please use this form to submit potential issues (with as much supporting information as you can provide) for consideration by the RISC. Supported by NERC staff, the RISC will work with the industry to help develop overall ERO strategy by identifying and prioritizing the most important reliability issues facing our industry and properly aligning resources to address them. By providing this information, you are helping to ensure the ERO is focusing on the correct priorities as it moves forward.

Click Here for: Nomination Form

For more information or assistance, please contact Andy Rodriquez.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Reliability Issues Steering Committee

December 17, 2012 | 12:00-5:00 p.m. EST

Florida Reliability Coordinating Council Offices
1408 N Westshore Blvd Suite 1002
Tampa, FL 33607
(813) 289-5644

Welcome, Introductions, Chair's Remarks, and Meeting Schedule

Monday, December 17 – Tampa FL
Thursday, January 24 – Webinar
Tuesday, February 12 – Atlanta, GA
Tuesday, March 12 –Dallas, TX
Tuesday, April 16 – Portland, OR
Wednesday, May 22 – TBD
Tuesday, June 18 – TBD
Thursday, July 11 – TBD
Thursday, August 8 – TBD
Thursday, September 19 – TBD
Tuesday, October 22? – TBD

NERC Antitrust Compliance Guidelines and Public Announcements

Agenda

1. **Unfinished Items**
   a. Prioritize all strategic risk categories (2 hours)
2. **New Items**
   a. Integrating with NERC Planning (2.5 hours)
   b. Nominations
      RISC discussion of issue nominations received prior to December 3.[1]
3. **Action Item Review**
4. **Adjourn**

[1] Any nomination received after this date will be reviewed at a future meeting of the RISC

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

PROJECT 2010-17 DEFINITION OF BES (PHASE 2)

Notes

1. Introduction

The Chair brought the meeting to order at 8:30 a.m. on Wednesday, November 14, 2012 at the NERC offices in Atlanta, GA. Meeting participants were:

Members		
Brain Evans-Mongeon, Utility Services	Pete Heidrich, FRCC, Chair	John Hughes, ELCON
Barry Lawson, NRECA, Vice Chair	Rich Salgo, Sierra Pacific Power	Jason Snodgrass, GTC
Jennifer Sterling, Exelon	Jonathan Sykes, PG&E	Ed Dobrowolski, NERC
Observers		
Mohammed Ahmed, AEP	Laura Anderson, NERC (day one only)	Paul Fiedler, BPA
Jeff Gindling, Duke	Bill Harm, PJM	Bill Hughes, Redding
Ruth Kloecker, ITC	Andres Lopez, FERC	John Martinsen, Snohomish
Alain Pageau, HQ	DeWayne Scott, TVA	Ken Shortt, Pacificorp
Tim Soles, Occidental	Phil Tatro, NERC	Phil Winston, Southern (day two only)

2. Review Emergency Logistics

The emergency logistics for the Atlanta office were reviewed.

3. Determination of Quorum

The rule for NERC Standard Drafting Teams (SDT) states that a quorum requires two-thirds of the voting members of the SDT to be physically present. Quorum was achieved for this meeting.

4. **NERC Antitrust Compliance Guidelines and Public Announcement**

   The NERC Antitrust Compliance Guidelines were reviewed and the public announcement warning was delivered.

5. **Membership Changes and Roster Updates**

   Jerry Murray is retiring and has submitted his resignation from the SDT. At this point in time there will be no request to replace him on the SDT.

   Jennifer Dering is out on medical leave. She will not be participating in SDT activities as a representative of NYPA or counted against quorum until she is re-instated by NYPA.

   There were no other changes to membership or roster information.

6. **Review Meeting Agenda and Objectives**

   The main goal of day one was to complete the review of responses to comments for the Guidance Document. Day two was reserved for addressing possible Phase 2 changes and clarifications.

7. **Liaison Reports**

   a. Standards Committee – Pete Heidrich

      There was no formal presentation on this project at the last meeting. The project was reported as on schedule.

   b. MRC/BOT – Pete Heidrich

      There was no report requested by the MRC/BOT at their November meeting.

   c. Planning Committee Executive Committee – Jeff Mitchell

      Jeff Mitchell was unable to attend this meeting. However, he previously reported that the Planning Committee is on target to achieve the December 20, 2012 deadline. A draft copy of the final report was provided to the SDT for their internal use and this draft was the basis for SDT discussion.

      The Planning Committee Executive Committee was specifically tasked with exploring the 100 kV bright-line. The draft recommendation is to keep the status quo. The final report will state that Planning Committee Executive Committee could not develop a technical justification for the 100 kV bright-line and that they could not develop a justification for any other value either.

   d. System Analysis and Modeling Subcommittee (SAMS) – Bill Harm

The SAMS draft recommendation is no minimum size for reactive devices. This would result in no change to the Phase 1 definition.

The SAMS draft recommendation is that the local network power flow issue be expanded to state that no power can flow out into the BES from any point of connection between the local network and the BES. Another SAMS draft recommendation is that the power flow limitation be constrained to normal and N-1 operations only. In addition, SAMS is suggesting draft recommendation of a 300 MW capacity constraint on the amount of load within a local network. No technical justifications for any of these positions were provided in the draft report nor were any technical analysis done to support the positions.

The 300 MW limit is due to a concern about the possible exclusion of major metropolitan areas if no constraint is imposed. However, SAMS presented no evidence in the draft that such a problem exists or that it was even studied. Three of the metropolitan areas cited in the draft report had representatives at the meeting or on the phone. PG&E stated that such a condition did not exist for San Francisco. Exelon assured the SDT that such a problem was not the case for Chicago. And Consolidated Edison reported no such situation would occur for New York City.

The SAMS draft also recommends that the determination for a local network be done in a planning environment rather than a real-time environment.

e. Reliability Assessment Subcommittee (RAS) – Phil Fedora

Section 3.4 of the draft report represents the recommended course of action from RAS. Once again, they will be recommending that the status quo be maintained. The report will state that no technical justification is possible for the generation thresholds but that no other values can be justified either.

In general, the SDT expressed its displeasure with the draft report. The SDT feels that the draft report is not providing what was asked and that industry will not be pleased with the lack of technical justifications provided for the definition threshold values. In addition, the Planning Committee expanded the scope of the request and is providing recommendations for items that were not requested by the SDT. The SDT is going to send a letter to the Planning Committee expressing its concerns with these issues. Items of concern are the lack of technical justifications and analysis, statements on local networks carving out major metropolitan areas with no justifications provided, misleading statements reflecting back on the September 2011 blackout, and providing recommendations on topics that were not requested. Each SDT member is encouraged to contact their Planning Committee representative with their concerns.

AI – Pete Heidrich will submit a letter to the Planning Committee expressing the dissatisfaction of the SDT with the draft Planning Committee report. This letter needs to be sent prior to the Planning Committee meeting in December.

8. **Review of Previous Action Items**

- Pete Heidrich will distribute the MRC/BOT presentation to the SDT members once it has been finalized. Completed.
  - Distributed to the plus list server on August 20, 2012.
- Ed Dobrowolski to contact NERC management to resolve the expectations and process to be followed to reconcile the BES definition and the ERO Statement of Compliance Registry Criteria as per the BES Definition Phase 2 SAR. Completed.
  - SDT will need to identify any proposed changes in the ERO Statement of Compliance Registry brought about by the Phase 2 BES definition in a memo to Mark Lauby who as an officer of the corporation can submit changes. The memo should contain justification for any suggested changes.
- Jonathan Sykes will draft a set of rules for how to apply the E1 exclusion to evaluations of applicability of the exclusion. Completed.
  - Distributed to the SDT leadership on August 23, 2012.

9. **Review of Guidance Document Comment Responses**

Q1: Inclusion I1 – Jeff Mitchell

Jeff Mitchell was unable to attend the meeting but he did send in draft responses. The main issue was the use of black/blue/green colors in the various diagrams. The SDT decided to place a legend on each diagram explaining the meanings of the different colors on the diagram as opposed to trying to adjust the color scheme for small segments to show BES vs. non-BES segments as this would make the diagrams harder to read. This comment was spread throughout the different questions. The same comment will be used in each response to this issue.

Q2: Inclusion I2 - Phil Fedora

There was some confusion and inconsistency surrounding the use of the terms 'generator site' and 'site boundary'. The term 'generator site boundary' will be used throughout the document. The term will be referenced using an adaptation of work that was done in this area in CA which was supplied by Bill Hughes.

The term 'off site' was deemed confusing and unnecessary and will be deleted.

The glossary definition of Load will be provided in the text of the document.

Q3: Inclusion I4 – Phil Fedora

The same comments from question 2 generally apply to question 4 as well.

In addition, breakers should be deleted from the I4 diagrams for consistency with other diagrams.

The language for interconnection agreements will be changed from 'should' to 'typically included'.

Q4: Inclusion I5 – Jason Snodgrass

Delete the references to breakers in the text boxes.

Delete Figure I5-2 as it is no longer needed.

Delete the breakers in figure I5-1.

Q5: Exclusion E1 – Jonathan Sykes

On page 23, change 'owner' to 'applicable entity'.

On pages 29 and 32, change 'a, b. and c' to 'a, b, or c'.

A diagram is needed to show the Blackstart Resource example.

Text for generator limitations similar to what is in the section on Exclusion E3 should be added.

All switches should be deleted.

This section needs to be checked for consistency of terminology.

Q6: Exclusion E2 – John Hughes

It needs to be emphasized once again that Exclusion E2 is only retail and that net capacity is the key, not nameplate.

Multiple interconnection points do not preclude the use of Exclusion E2.

Q7: Exclusion E3 – Rich Salgo

The text needs to state that entities must be prepared to justify local network determinations.

In Phase 1, no flow is allowed out of the local network in any situation.

The presence of a Blackstart Resource negates the use of Exclusion E3.

Cranking Paths are not included by the use of Exclusion E3.

In Figure E3-2, clarify that flow can be out at one or more points.

Q8: System Diagram – Pete Heidrich

Many of the comments for question 8 are similar to those raised in questions 1 – 7.

The hierarchical discussion will be added in the front sections of the document.

The exclusions may be re-ordered in Phase 2 to match the hierarchy.

Add a Blackstart Resource to the new 69 kV section to the S diagrams in order to show that Cranking Paths are not included in the BES.

Q9: General – Barry Lawson

The SDT can't remove the disclaimer. It can only state its intent.

Rules of Procedure section numbers should be included in the text.

There should be text sections on Inclusion I3 and Exclusion E4 to show that they weren't missed.

There should be a glossary section at the end of the document.

The introduction needs some clean up.

Black and white printing is not a feasible alternative.

The core definition is not constrained simply to a.c. power.

10. **Discuss Need for Supplemental SAR**

There is a consistency issue between Inclusions I2 and I4. Wind, etc., is being treated differently and there is a question as to whether this is fair.

There is also a possible reliability issue as was pointed out by several commenters. These commenters question whether the Phase 1 handling of Inclusion I4 is really addressing the true reliability issue. The comments point to the common point of failure as being the more important reliability issue. This concept could present other problems though if Generator Owners and Generator Operators suddenly didn't need to register.

Data exchange and modeling concerns are not the issue – they are handled in other existing or proposed standards.

The SDT decided that a change was needed to bring in these reliability concerns but that a Supplemental SAR was not required. The SDT believes that the changes being proposed can be made within the scope of the approved Phase 2 SAR.

Inclusion I2 will be for any type unit or units within a single generator site boundary. Inclusion I4 will handle multiple sites. As an example of how this would be shown moving forward, Figure I4-2 would show that the transformer on the far right and the downstream bus would be included in the BES as a single point of connection where generation from multiple sites aggregates to more than 75 MVA. The individual generators in this diagram would not be included in the BES as they are less than 20 MVA individually or 75 MVA per site. A new drawing will be created to display this concept and would be included in a Phase 2 revision of the Guidance Document. Revised language for the inclusions was crafted and distributed to the SDT for approval. Once this language is approved by the SDT it will be part of the initial Phase 2 posting to the industry.

11. **Definition Clarification Items**

a. Discuss possible changes to threshold values

i. 100 kV bright-line

The draft recommendation from the Planning Committee is for retaining the status quo. The report will state that there is no technical justification for change. The SDT generally agrees with staying at 100 kV but is disappointed that no technical justification for that value was provided.

ii. Generation

1. Unit limits in Inclusion I2 and I4

The draft recommendation from the Planning Committee is for retaining the status quo. The report will state that there is no technical justification for change. Furthermore, the report will state that there is no technical justification possible for any threshold value(s). The SDT is disappointed that no technical justification for those values was provided.

It was pointed out that the applicability of standards may be of assistance in trying to sort through this issue. Also, the exception process can be used to sort out one-off situations. However, it may be that this position will drive an inordinate number of exception requests and that this may lead to a demand to re-visit this issue in the future.

Nothing formal can be done until the final report is issued but in general, the SDT can only go forward with the information it was provided so the 20/75 MVA thresholds should be retained.

The SDT is going to report back to the Standards Committee on this issue to inform them that the desired outcome of the Planning Committee assignment was not achieved.

In the meantime, the SDT will form a sub-group to delve into the Planning Committee report in detail to see if there is any room for movement. The sub-group will be led by Rich Salgo and include Jonathan Sykes and Brian Evans-Mongeon. If other members or observers want to participate they should contact Rich Salgo directly. The sub-group will distribute its findings to the SDT for review no later than January 18, 2013.

AI – Rich Salgo to lead a sub-group that will look into the Planning Committee report in detail to see if there is any room for the SDT to move on threshold issues moving forward in Phase 2. This work will be distributed to the SDT for review no later than January 18, 2013.

2. Single threshold for generation

   The discussion here followed the same general line as above and the sub-group will include this in their work.

iii. Local network

1. Power flow

   Due to time limitations, none of the items below this in the agenda were discussed.

2. Size limitation

iv. Reactive resources

b. Should reactive resources be specifically included in Exclusions E1 and E3?

c. Discuss the need for including the net capacity delivered to the BES from customer-owned generation in Exclusions E1 and E3 generation totals

d. Discuss the need to include statements concerning the exclusion of customer-owned 'transmission' equipment in Exclusion E2

e. Discuss the need to change the sequence of Exclusions based on the hierarchical application of the definition which starts with Exclusion E2 and then goes through Exclusion E4 to Exclusion E3 and finishes with Exclusion E1

f. Discuss any needed changes to the ERO Statement of Compliance Registry Criteria due to the revised BES definition

12. **Phase 2 Schedule**

Currently the project is on schedule. However, the SDT will not be able to post early due to the issues surrounding the Planning Committee report on threshold values. The SDT has to wait for the final report and then additionally, wait for any direction from the Standards Committee. The SDT should be able to meet the original posting schedule which is early April as the target date.

13. **Next Steps**

The Guidance Document does not have to be posted for comments again. Once the suggested changes are made and vetted by the SDT it can be published as the reference document it is intended to be. The publication will need to wait on the issuance of the final Order on this matter so that the final document reflects the Commission's findings. However, if the Order is not forthcoming, the SDT may need to publish anyway due to the pressing need for such a document within the industry. If there is no Order by the end of January 2013, then the SDT will consider publication.

As discussed above, the SDT will send a letter to the Planning Committee expressing its disappointment with the draft report.

The SDT will also provide an update on the draft report and its possible consequences to the Standards Committee.

14. Future Meetings

The face-to-face meeting tentatively scheduled for December 4 – 5, 2012 has been cancelled in favor of a conference call/ web ex on December 4, 2012 from 1:00 p.m. to 5:00 p.m. EST. The main goal of this call will be to resolve the Inclusion I2/I4 language. Other standing agenda items will be discussed as time permits. Details for the call will be sent later.

The next face-to-face meeting of the SDT is scheduled for Wednesday, February 20, 2013 and Thursday, February 21, 2013 in San Francisco, CA at the PG&E offices. This may be the last meeting prior to posting so members are requested to allot the full time of the meetings on their schedules so that all open items can be discussed and resolved. Logistical information will be sent later.

15. Action Item Review

The following action items were developed during this meeting:

- Pete Heidrich will submit a letter to the Planning Committee expressing the dissatisfaction of the SDT with the draft Planning Committee report. This letter needs to be sent prior to the Planning Committee meeting in December.
- Rich Salgo to lead a sub-group that will look into the Planning Committee report in detail to see if there is any room for the SDT to move on threshold issues moving forward in Phase 2. This work will be distributed to the SDT for review no later than January 18, 2013.

16. Adjourn

The Chair thanked NERC for its hospitality and adjourned the meeting at 4:00 p.m. on Thursday, November 15, 2012.

From: Jordan Mallory
To: Jordan Mallory
Subject: NERC Updated Webinar Announcement: Winter Preparation for Severe Cold Weather - December 10, 2012
Date: Tuesday, November 27, 2012 5:08:15 PM

Updated Webinar Announcement

Winter Preparation for Severe Cold Weather

December 10, 2012| 2:30–4:00 p.m. ET

Please see the updated link below of the Draft Reliability Guideline: Winter Weather Readiness – Current Industry Practices.

Click here for: Southwest Cold Weather Event Report

Click here for: Lessons Learned from Southwest Cold Weather Event

Click here for: Draft Reliability Guideline: Winter Weather Readiness - Current Industry Practices

Teleconference: 1800-269-3762 | Access Code: 4462733| Broadcast Audio Code: 210674

Topic:	NERC will conduct a webinar to remind entities of the need to prepare for severe cold weather, while also reiterating lessons learned from previous extreme cold weather events. During the webinar, information will be shared from the Southwest Cold Weather Event of February 2011. Additionally, a status update will be provided regarding the development of the NERC Operating Committee Reliability Guideline Winter Weather Readiness – Current Industry Practices.
Invited Audience:	NERC Members and Industry Stakeholders
Access Information:	Webinar Registration Link

For more information or assistance, please contact Jordan Mallory (via email).

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DRAFT Reliability Guideline: Winter Weather Readiness – Current Industry Practices

Preamble:

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). Reliability Guidelines provide suggested guidance on a particular topic for use by BES users, owners, and operators according to each entity's circumstances. Reliability Guidelines are not to be used to provide binding norms, establish mandatory reliability standards, or create parameters by which compliance to standards is monitored or enforced.

Introduction:

This Reliability Guideline is applicable to electricity sector organizations responsible for the operation of the BES. It provides general concepts that may be considered when developing a winter weather readiness program. This guideline provides a general framework for identifying the concepts and steps to consider for an effective program with a focus on maintaining individual unit reliability. This document, written in the form of a guideline, is a collection of industry practices compiled by the NERC Operating Committee (OC). The use of these methodologies and guidelines are strictly voluntary**.**

Purpose:

The purpose of this guideline is to document and share current winter weather readiness practices and procedures from across the industry that has been found to enhance the effectiveness of these programs. These are not mapped to existing or future mandatory requirements, but rather are intended to show the breadth of industry practices concerning winter weather readiness.

Assumptions:

A. Each entity is responsible and accountable for maintaining unit reliability.

B. Entities should develop and apply plant-specific guidelines (both seasonal and severe event based preparedness) as appropriate based on factors such as geographical location, technology and plant configuration.

Guideline Details:

Components of an effective winter weather readiness program (both seasonal preparedness and severe event based preparedness) may include:

I. Safety

Management must emphasize that personnel safety remains the top priority during winter weather events. Management ensures that job safety briefings are conducted during preparation for winter weather events as well as during response to winter weather events.

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II. Management Roles and Expectations

A. Senior Management

1) Sets expectations for safety, environmental compliance, and generation.

2) Ensures that a winter preparation process exists for each operating location for seasonal preparedness, including severe winter weather event preparedness, and executed as necessary (referred to hereafter as a winter weather preparation procedure)

3) Consider a fleet-wide annual winter preparation meeting and/or training exercise to share best practices and lessons learned.

4) Encourage sharing of insights across the fleet and through industry associations such as the North American Generator Forum, EEI, NERC Event Analysis Subcommittee, etc. (formal groups or other informal networking forums).

B. Plant Management

1) Develop a winter weather preparation procedure, including site specific procedures and checklists for seasonal winter preparedness as well as severe winter weather event preparedness. Each site should consider a plant manager appointed designee, responsible for keeping this procedure updated with industry identified best practices and lessons learned.

2) Ensure the site specific winter weather preparation procedure includes processes, staffing plans, and timelines that direct all key activities before, during and after severe winter weather events.

3) Conduct a plant readiness review prior to a severe winter weather event.

4) Ensure completion of the winter weather preparation procedure.

5) Encourage plant staff to look for areas at risk due to winter conditions and bring up opportunities to improve readiness and response.

6) Following each winter, conduct an evaluation of the effectiveness of the winter weather preparation procedure and incorporate lessons learned.

III. Evaluation of Potential Problem Areas

Identify and prioritize components, systems, and other areas of vulnerability which may experience freezing problems or other cold weather operational issues. This includes equipment that has the potential to:

A. Initiate an automatic unit trip,

B. Impact unit start-up,

C. Initiate automatic unit runback schemes and/or cause partial outages,

D. Cause damage to the unit,

E. Adversely affect environmental controls that could cause full or partial outages,

F. Adversely affect the delivery of fuel or water to the units,

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G. Cause other operational problems such as slowed or impaired field devices, or

H. Create a safety hazard.

For safety reasons, fire protection systems should also be included in this identification process. These problem areas should be noted in the site specific winter weather preparation procedure.

Typical problem areas during cold weather include, but are not limited to:

A. Level transmitters

1) Drum level transmitters and sensing lines
2) Condensate tank level transmitters and sensing lines
3) De-aerator tank level transmitters and sensing lines
4) Hotwell level transmitters and sensing lines

B. Pressure Transmitters

1) Gas turbine combustor pressure transmitters and sensing lines
2) Feed water pump pressure transmitters and sensing lines
3) Condensate pump pressure transmitters and sensing lines
4) Steam pressure transmitters and sensing lines

C. Flow Transmitters

1) Steam flow transmitters and sensing lines
2) Feed water pump flow transmitters and sensing lines
3) High pressure steam attemperator flow transmitters and sensing lines

B. Instrument Air System

D. Motor-Operated Valves, Valve Positioners, and Solenoid Valves

E. Drain Lines and Steam Vents

1) Instrument air compressor drains

F. Emergency Generators (including Blackstart generators) for critical system(s) backup

G. Water Pipes and Fire Suppression Systems

1) Low/no water flow piping systems

H. Fuel Supply

1) Coal piles and coal handling equipment
2) Transfer systems for backup fuel supply
3) Gas supply regulators, other valves and instrumentation (may require coordination with gas pipeline operator)

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IV. Processes and Procedures

A winter weather preparation procedure should be developed for seasonal winter preparedness, as well as severe winter weather preparedness. Components of an effective winter weather preparation procedure are included as Attachment 1.

After a severe winter weather event, entities should utilize a corrective action process to formally identify lessons learned. Procedures should be reviewed and updated using these lessons learned after every winter event to institutionalize knowledge from prior events (what worked well or did not work well during the event).

V. Training

A. Coordinate annual training in winter specific and plant specific awareness and maintenance training. This may include response to freeze protection panel alarms, troubleshooting and repair of freeze protection circuitry, identification of plant areas most affected by winter conditions, review of special inspections or rounds implemented during severe weather, knowledge of the ambient temperature for which the freeze protection system is designed, and lessons learned from previous experiences or the NERC Lessons Learned program.

   1) Consider holding a winter readiness meeting on an annual basis to highlight preparations and expectations for severe cold weather.

   2) Operations personnel may review cold weather scenarios affecting instrumentation readings, alarms, and other indications on plant control systems.

   3) Ensure appropriate NERC GADS coding for unit derates or trips as a result of a severe winter weather events to promote lessons learned, knowledge retention, and consistency. Examples may include NERC GADS code 9036 “Storms (ice, snow, etc.)” or code 9040 “Other Catastrophe.”

VI. Winter Event Communications

A. Before a severe winter weather event, plant management should consider communicating with their appropriate senior management that the site specific winter weather preparation procedure, checklists, and readiness reviews have been completed.

B. Before and during a severe winter weather event, the affected entity (ies) will keep the Balancing Authority up to date on changes to plant availability.

C. After a generating plant trip, derate, or failure to start due to severe winter weather, Plant Management, as appropriate, will conduct an analyses, develop lessons learned, and incorporate best practices.

   1) This process may include a feedback loop to enhance current winter weather readiness programs, processes, procedures, checklists and training (continuous improvement).

   2) Sharing of technical information and lessons learned may be provided to the industry, as appropriate, through the NERC Event Analysis Program or some other method.

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Related Documents and Links:

1. *Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011,* dated August 2011, Federal Energy Regulatory Commission and North American Electric Reliability Corporation
2. *Winter Weather Readiness Guidelines for Texas Generators,* dated April 13, 2011, Calpine, CPS Energy, LCRA, Luminant, and NRG Energy
3. *Electric Reliability Organization Event Analysis Process,* dated February 2012, ERO Event Analysis Process and associated Lessons Learned

Revision History:

Date	Version Number	Reason / Comments
12/03/2012	1.0	Initial Version – *Winter Weather Readiness*

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Attachment 1

Elements of a Winter Weather Preparation Procedure (Seasonal Preparedness and Severe Winter Weather Event Preparedness)[1]

A. Work Management System

1) Review Work Management System to ensure adequate annual preventative work orders exist for freeze protection and/or winter weather preparedness.

2) Ensure all freeze protection and/or winter weather preparedness preventative work orders are completed prior to the onset of the winter season.

3) Suspend freeze protection measures and remove freeze protection equipment after the last probable freeze of the winter. This may be a plant specific date established by senior management.

4) Ensure all engineered modification and construction activities are performed such that the changes maintain winter readiness for the plant. Newly built plants or engineered modifications can be more susceptible to winter weather.

B. Critical Instrumentation and Equipment Protection

1) Ensure all critical site specific problem areas (as noted above in section III. Evaluation of Potential Problem Areas) have adequate protection to ensure operability during a severe winter weather event. Emphasize the points in the plant where equipment freezing would cause a generating plant trip, de-rate, or failure to start.

C. Insulation, Heat Trace, and Other Protection Options – Processes and procedures that verify adequate protection and necessary functionality (by primary or alternate means) before and during winter weather. Consider the effect of wind chill when applying freeze protection. Considerations include but are not limited to:

1) Insulation thickness, quality and proper installation

   i. Verify the integrity of the insulation on critical equipment identified in the winter weather preparation procedure. Following any maintenance, insulation should be re-installed to original specifications.

2) Heat trace capability and electrical continuity/ground faults

   i. Perform a complete evaluation of all heat trace lines, heat trace power supplies (including all breakers, fuses, and associated control systems) to ensure they maintain their accuracy. This inspection should include checking for loose connections, broken wires, corrosion, and other damage to the integrity of electrical insulation which could lead to the heat trace malfunctioning. Heat trace amperage and voltage should be measured, if possible, to determine whether the circuits are producing the design output. If there are areas where heat tracing is not functional, an alternate means of protection should be identified in the winter weather preparation procedure.

[1] Plants that will remain offline during the winter season would not need to perform winterization preparations unless it is necessary for asset protection/preservation.

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ii. Evaluate the current installation of heat trace and insulation on critical lines making sure heat trace is applied properly (i.e., wrapped around the valve and not just across the valve body).

iii. Utilize manufacturer's recommendations in determining the useful life of the heat trace equipment for developing a routine preventative maintenance and replacement plan or schedule.

iv. Re-install removed or disturbed heat tracing following any equipment maintenance to restore heat tracing integrity and equipment protection.

v. Update and maintain all heat tracing circuit drawings and labeling inside cabinets.

3) Wind breaks

i. Install permanent or temporary wind barriers as deemed appropriate to protect critical instrument cabinets, heat tracing and sensing lines.

4) Heaters and Heat Lamps

i. Ensure operation of all permanently mounted and portable radiant heaters.

ii. Evaluate plant electrical circuits to ensure they have enough capacity to handle the additional load. Circuits with ground fault interrupters (GFIs) should be continuously monitored to make sure they have not tripped due to condensation.

iii. Fasten in place to prevent unauthorized relocation.

5) Covers, Enclosures, and Buildings

i. Install a box or enclosure with inside heat for some transmitters.

ii. Install covers on valve actuators to keep the actuator from accumulating ice.

iii. Inspect building penetrations, doors, fan louvers, and other openings for potential exposure of critical equipment to the elements.

D. Supplies – Prior to the onset of the winter season, ensure adequate inventories of all commodities, equipment and other supplies that would aid in severe winter weather event preparation or response, and that they are readily available to plant staff. Supplemental equipment might include:

1) Tarps
2) Portable heaters and/or heat lamps
3) Scaffolding
4) Blankets
5) Extension cords
6) Kerosene/propane
7) Temporary enclosures
8) Temporary insulation

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9) Plastic rolls
10) Portable generators
11) Portable lighting
12) Instrumentation tubing
13) Handheld welding torches
14) Ice removal chemicals and equipment
15) Cold weather PPE as appropriate to the respective regions

Prior to the onset of a severe winter weather event, an inventory should be conducted of critical supplies needed to keep the plant operational. Appropriate deliveries should be scheduled based on the severity of the event, lead times, etc. Operational supplies might include:

1) Aluminum Sulfate
2) Anhydrous Ammonia
3) Aqueous Ammonia
4) Carbon Dioxide
5) Caustic Soda
6) Chlorine
7) Diesel Fuel
8) Ferric Chloride
9) Gasoline (Unleaded)
10) Hydrazine
11) Hydrogen
12) Lighter Oil (#2 Diesel)
13) Sulfuric Acid
14) Calibration Gases
15) Lubricating Oils
16) Welding Supplies
17) Limestone

E. Staffing

1) Consideration of enhanced staffing (24x7) during severe winter weather events.
2) Arrangements for lodging and meals.
3) Arrangements for transportation as needed.
4) Support and appropriate staffing from Transmission Service Providers for plant switchyard to ensure minimal line outages.

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F. Communications

1) Ensure appropriate communication protocols are followed during a severe winter weather event.

2) Identify a back-up communication option in case the primary system is not working

3) Ensure communication is discussed as part of the job safety briefing during a severe winter weather event.

G. Special Operations Instruction (just prior to or during a severe winter weather event)

1) Consider employing the "buddy system" during severe winter weather events to promote personnel safety.

2) Institute operator rounds utilizing cold weather checklists to verify critical equipment is protected – i.e. pumps running, heaters operating, igniters tested, barriers in place, temperature gauges checked, etc.

   i. Instrumentation and equipment in enclosed spaces (e.g. pump rooms) can still freeze. Room temperatures may need to be monitored.

3) Test dual fuel capability and ensure adequate fuel supply (where applicable).

4) Consider pre-warming and/or early start-up of scheduled units prior to a forecasted severe winter weather event.

5) Run emergency generators immediately prior to severe winter weather events to help ensure availability. Review fuel quality and quantity.

6) Place in service critical equipment such as intake screen wash systems, cooling towers, auxiliary boilers, and fuel handling equipment where freezing weather could adversely impact operations or forced outage recovery.

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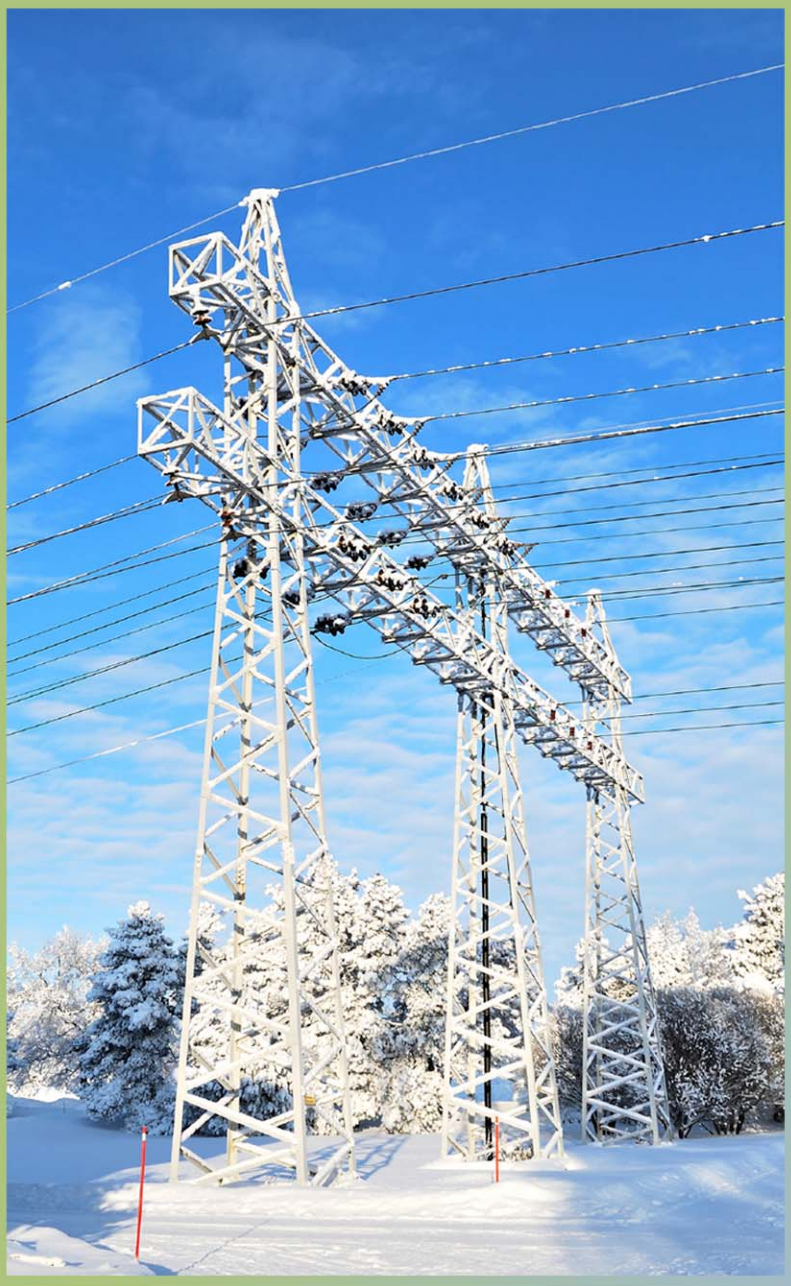

Report on

Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011

Causes and Recommendations

Prepared by the Staffs of the
Federal Energy Regulatory Commission
and the
North American Electric
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I. Introduction

The southwest region of the United States experienced unusually cold and windy weather during the first week of February 2011. Lows during the period were in the teens for five consecutive mornings and there were many sustained hours of below freezing temperatures throughout Texas and in New Mexico. Low temperatures in Albuquerque, New Mexico ranged from 7 degrees Fahrenheit to -7 degrees over the period, compared to an average high of 51 degrees and a low of 26 degrees. Dallas temperatures ranged from 14 degrees to 19 degrees, compared to an average high of 60 degrees or above and average lows in the mid-to-upper 30s. Many cities in the region would not see temperatures above freezing until February 4. In addition, sustained high winds of over 20 mph produced severe wind chill factors.

Electric entities located within the Texas Reliability Entity, Inc. (TRE), the Western Electricity Coordinating Council (WECC), and the Southwest Power Pool (SPP) were affected by the extreme weather, as were gas entities in Texas, New Mexico and Arizona.

Between February 1 and February 4, a total of 210 individual generating units within the footprint of the Electric Reliability Council of Texas, Inc. (ERCOT), which covers most of Texas, experienced either an outage, a derate, or a failure to start. The loss of generation was severe enough on February 2 to trigger a controlled load shed of 4000 MW, which affected some 3.2 million customers. On February 3, local transmission constraints coupled with the loss of local generation triggered load shedding for another 180,000 customers in the Rio Grande Valley in south Texas. El Paso Electric Company (EPE), which is outside the ERCOT region, lost approximately 646 MW of local generation over the four days beginning on February 1. It implemented rotating load sheds on each of the days from February 2 through February 4, totaling over 1000 MW and affecting 253,000 customers. The Salt River Project Agricultural Improvement and Power District (SRP), located in Arizona, lost 1050 MW of generation on February 1 through February 2 and shed load of 300 MW, affecting approximately 65,000 customers. The New Mexico communities of Alamogordo, Ruidoso, and Clayton lost approximately 26 MW of load, affecting a little over 21,000 customers, when Public Service Company of New Mexico (PNM) experienced localized transmission failures, although these were largely unrelated to the extreme weather.

In total, approximately 1.3 million electric customers were out of service at the peak of the event on February 2, and a total of 4.4 million were affected over the course of the event from February 2 through February 4.

Natural gas customers also experienced extensive curtailments of service during the event. These curtailments were longer in duration than the electric outages, because relighting customers' equipment has to be accomplished manually at each customer's location. Local distribution companies (LDCs) interrupted gas service to more than 50,000 customers in New Mexico, Arizona and Texas; New Mexico was the hardest hit with outages of over 30,000 customers in areas as widespread as Hobbs, Ruidoso, Alamogordo, Silver City, Tularosa, La Luz, Taos, Red River, Questa, Española, Bernalillo and Placitas.

In the wake of these events, the Arizona Corporation Commission, the Public Regulation Commission of New Mexico, the Public Utilities Commission of Texas (PUCT), the Texas Railroad Commission (TRC), the New Mexico state legislature and the Texas state legislature all initiated inquiries or investigations. The PUCT directed TRE, the regional entity authorized by the North American Electric Reliability Corporation (NERC) to cover the ERCOT region, to investigate the decisions and actions ERCOT took in initiating the rolling blackouts.

On February 7, 2011, NERC announced that it would work with the affected Regional Entities to prepare an event analysis that would examine the adequacy of preparations for the event and identify potential improvements and lessons learned. NERC also stated it would review electric and natural gas interdependencies, in light of the shift toward a greater reliance on natural gas to produce electricity.

On February 14, the Federal Energy Regulatory Commission (FERC) initiated an inquiry into the Southwest outages and service disruptions. The inquiry had two objectives: to identify the causes of the disruptions, and to identify any appropriate actions for preventing a recurrence of the disruptions. FERC stated it was not at that time initiating an investigation into whether there may have been violations of applicable regulations, requirements or standards under FERC's jurisdiction, and that any decisions on whether to initiate enforcement investigations would be made later. Consequently, while this report describes actions which in some cases appear to warrant further investigation, it does not reach any conclusions as to whether violations have occurred.

From the beginning of their inquiries into the causes of the outages and disruptions, the staffs of FERC and NERC have cooperated in their data gathering and analysis. On May 9, FERC and NERC announced their staffs would create a joint task force to combine their separate inquiries. This report is a product of that effort.

The inquiry performed by the joint task force was far-reaching. Noted below in summary form are some of the steps taken by the task force to develop its understanding of the electric and natural gas disruptions that were experienced in the Southwest in early February.

Scope of Data Reviewed

The task force received approximately 54 GB of data through data requests issued to entities in both the electric and natural gas industries, conducted numerous follow-up calls and meetings, and issued follow-up requests to discuss questions raised by the data responses.

For the electric industry, the task force issued 122 data requests to generator operators, transmission operators, balancing authorities, and a reliability coordinator. The task force also utilized event analysis information which NERC and the affected Regional Entities received from 79 registered entities (72 from TRE, four from WECC and three from SPP). Additional event information was received through a request for information issued by NERC and Regional Entities to those entities affected by the extreme weather event. For the gas industry, the task force issued 92 data requests to pipelines (interstate and intrastate), storage facilities, gas processing plants, producers, and public utilities.

The data compiled by the task force focused on the causes of the outages and curtailments during the February cold weather event, critical entities' preparations for the forecasted cold weather and their performance in connection with the rolling blackouts and natural gas curtailments, and any lessons learned that could be applied in the future. As part of its analysis, the task force also reviewed historical data and recommendations compiled during past cold weather events in Texas and elsewhere in the Southwest, to determine whether the 2011 event was unprecedented or whether entities might have been better prepared to deal with it.

Electric Facility Site Visits

Staff from FERC and NERC, together with representatives of TRE and WECC, conducted site visits with various entities involved in the outages, toured facilities and conducted interviews with operations personnel, compliance personnel and company executives. The task force visited ERCOT, four transmission operators in ERCOT, and 15 generators in ERCOT (including coal, natural gas, and wind units); two generators in WECC; and two balancing authorities in WECC. During the generator site visits the task force toured the units, viewing any equipment that led to trips, derates, or failures to start; viewed winterization measures; and discussed maintenance and winterization processes,

fuel supply and market participation. During visits to the balancing authorities and transmission operators, the task force toured control centers and discussed the progression of the events, including specifics on load forecasting, market mechanics, system operations, load shedding and load restoration. The task force also discussed transmission system winterization and load shedding procedures with the transmission operators.

Natural Gas Meetings

The task force conducted numerous meetings with various entities from the gas industry to discuss the curtailments and shortages experienced in early February and the specifics of the entities' winter operations. These meetings included operations and regulatory personnel from two interstate pipelines doing business in Texas, New Mexico, Arizona, Colorado, and California; one LDC/intrastate pipeline located in New Mexico; one LDC from Arizona; and one intrastate pipeline located in Texas. The meetings focused on the companies' preparations for the storm, communications among LDCs, pipelines, marketers, and producers about unfolding events, system operations, underlying causes of the gas supply problems, and lessons learned. In most instances, interviews led to supplemental data requests that provided additional information about the events. The task force also held numerous telephone conferences with companies in the pipeline, LDC, processing and production sectors, both to gather information and to clarify information received in response to data requests.

Outreach Meetings

Task force staff conducted outreach meetings with the following industry associations and groups: the Electric Power Supply Association, the American Gas Association, the Independent Petroleum Association of America, the Texas Pipeline Association, the Interstate Natural Gas Association of America, the Natural Gas Supply Association, the Edison Electric Institute, the National Rural Electric Cooperative Association, the American Public Power Association, and the (ERO) Southwest Outage Advisory Panel. The task force shared its preliminary findings and recommendations on a non-public basis with members of these organizations in order to obtain feedback and, with respect to the recommendations, input as to their practicality and feasibility. The feedback and input provided by these organizations was considered and in a number of instances reflected in the findings and recommendations included in this report.

Coordination with State Inquiries

The task force also reviewed materials acquired in the course of inquiries into the event conducted by legislative bodies and regulatory commissions. The

task force followed legislative and regulatory hearings in Arizona, New Mexico and Texas and reviewed transcripts, testimony and webcasts from the proceedings.

Through contacts with state regulatory agencies, staff was able to review responses to data requests issued by those bodies to ensure that the task force was in possession of all potentially relevant materials. Task force staff also monitored legislative efforts taken in response to the February outage, including conferring with sponsors of pertinent legislation concerning, among other things, the anticipated impacts of their proposals. The task force tracked the bills throughout the legislative process. In addition, as regulatory agencies moved forward with their inquiries into the outage, task force staff reviewed draft and final copies of all relevant reports.

The task force also collaborated with ERCOT's Independent Market Monitor (IMM), which conducted an inquiry into potential market manipulation during the event at the request of the PUCT. Task force staff conducted calls with the IMM to discuss market conditions and reviewed its written assessment of the market impacts from the event. The task force also contacted the TRC regarding gas curtailment matters, submitted written questions about the TRC's activities in connection with the event, and reviewed all information the TRC collected concerning the event.

To assist in its analysis of the materials received, the task force commissioned one outside consultant's study to examine impacts of the cold weather event on gas production, reviewed studies conducted on behalf of regulatory and other bodies, and prepared extensive in-house studies by staff analysts.

This report documents the information received by the task force and presents the task force's conclusions as to the causes of the electric outages and natural gas curtailments that occurred during the February 2011 event. It is divided into several sections, beginning with an overview of the electric and natural gas industries that provides background for the event, discusses the event itself and prior cold weather events in the region, and ends with a summary of key findings and recommendations. Also included are a list of acronyms, a glossary, and a number of appendices which treat in fuller detail many of the matters mentioned in the body of the report.

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II. Executive Summary

The arctic cold front that descended on the Southwest during the first week of February 2011 was unusually severe in terms of temperature, wind, and duration of the event. In many cities in the Southwest, temperatures remained below freezing for four days, and winds gusted in places to 30 mph or more. The geographic area hit was also extensive, complicating efforts to obtain power and natural gas from neighboring regions.

The storm, however, was not without precedent. There were prior severe cold weather events in the Southwest in 1983, 1989, 2003, 2006, 2008, and 2010. The worst of these was in 1989, the prior event most comparable to 2011. That year marked the first time ERCOT resorted to system-wide rolling blackouts to prevent more widespread customer outages. In all of those prior years, the natural gas delivery system experienced production declines; however, curtailments to natural gas customers in the region were essentially limited to the years 1989 and 2003.

Electric

Going into the February 2011 storm, neither ERCOT nor the other electric entities that initiated rolling blackouts during the event expected to have a problem meeting customer demand. They all had adequate reserve margins, based on anticipated generator availability. But those reserves proved insufficient for the extraordinary amount of capacity that was lost during the event from trips, derates, and failures to start.

In the case of ERCOT, where rolling blackouts affected the largest number of customers (3.2 million), there were 3100 MW of responsive reserves available on the first day of the event, compared to a minimum requirement of 2300 MW. But over the course of that day and the next, a total of 193 ERCOT generating units failed or were derated, representing a cumulative loss of 29,729 MW. Combining forced outages with scheduled outages, approximately one-third of the total ERCOT fleet was unavailable at the lowest point of the event. These extensive generator failures overwhelmed ERCOT's reserves, which eventually dropped below the level of safe operation. Had ERCOT not acted promptly to shed load, it would very likely have suffered widespread, uncontrolled blackouts throughout the entire ERCOT Interconnection.

ERCOT also experienced generator outages in the Rio Grande Valley on February 3, again due to the cold weather. This area is transmission constrained,

and the loss of local generation led to voltage concerns that necessitated localized load shedding.

Spot prices in ERCOT hit the $3,000 per MWh cap on February 2, the worst day of the event. Given the high demand and the huge loss of generation, this was not a surprising development. In fact, very high prices are an expected response to scarcity conditions, one that is built into ERCOT's energy-only market. ERCOT's IMM reviewed market performance during the event and found no evidence of market manipulation.

EPE and SRP likewise suffered numerous generator outages, necessitating load shed of 1023 MW in EPE's case, and 300 MW in SRP's case. As with ERCOT, many of these generators failed because of weather-related reasons.

A number of entities within SPP also experienced outages during the event. In their case, however, load shedding was not required, principally because the utilities were able to purchase emergency energy from other SPP members. One other utility in the Southwest, PNM, experienced blackouts, but these were localized and the result of transmission outages that were mostly unrelated to the weather.

The actions of the entities in calling for and carrying out the rolling blackouts were largely effective and timely. However, the massive amount of generator failures that were experienced raises the question whether it would have been helpful to increase reserve levels going into the event. This action would have brought more units online earlier, might have prevented some of the freezing problems the generators experienced, and could have exposed operational problems in time to implement corrections before the units were needed to meet customer demand.

The February event underscores the need to have sufficient black start units available, particularly in the face of an anticipated severe weather event. In ERCOT's case, for instance, nearly half of its black start units were either on scheduled outage at the time of the event or failed during the event itself, jeopardizing the utility's ability to promptly restore the system had an uncontrolled, ERCOT-wide blackout occurred.

The majority of the problems experienced by the many generators that tripped, suffered derates, or failed to start during the event were attributable, either directly or indirectly, to the cold weather itself. For the Southwest as a whole, 67 percent of the generator failures (by MWh) were due directly to weather-related causes, including frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing, low temperature cutoff limits, and the like. At least

another 12 percent were indirectly attributable to the weather (occasioned by natural gas curtailments to gas-fired generators and difficulties in fuel switching).

Low temperatures returned to the region on February 10. In fact, ERCOT set a new winter peak that day. But no load shedding proved necessary, largely because the temperatures were not quite as cold or sustained as those of the previous week, the winds were less severe, and many of the repairs and protective measures taken by the generators on February 2 remained in place.

Natural Gas

Problems on the natural gas side largely resulted from production declines in the five basins serving the Southwest. For the period February 1 through February 5, an estimated 14.8 Bcf of production was lost. These declines propagated downstream through the rest of the gas delivery chain, ultimately resulting in natural gas curtailments to more than 50,000 customers in New Mexico, Arizona, and Texas.

The production losses stemmed principally from three things: freeze-offs, icy roads, and rolling electric blackouts or customer curtailments. Freeze-offs occurred when the small amount of water produced alongside the natural gas crystallized or froze, completely blocking off the gas flow and shutting down the well. Freeze-offs routinely occur in very cold weather, and affected at least some of these basins in all of the six recent cold weather events in the Southwest with the possible exception of 1983, for which adequate records are not available. During the February event, icy roads prevented maintenance personnel and equipment from reaching the wells and hauling off produced water which, if left in holding tanks at the wellhead, causes the wells to shut down automatically. The ERCOT blackouts or customer curtailments affected primarily the Permian and Fort Worth Basins and caused or contributed to 29 percent (Permian) and 27 percent (Fort Worth) of the production outages, principally as a result of shutting down electric pumping units or compressors on gathering lines.

Processing plants suffered some mechanical failures, although most of their shortfalls resulted from problems upstream at the wellhead. The production declines, coupled with increased customer demand, reduced gas volume and pressure in the pipelines and in those limited storage facilities serving the Southwest. These entities in turn were unable in some instances to deliver adequate gas supplies to LDCs.

When LDCs suffer declines in gas pressure on their systems, they must reduce the amount of gas being consumed to prevent pressures from falling so low that their entire systems might fail. As a result of the high gas demand and the

falling pressures on their systems, four LDCs in New Mexico, Arizona and Texas were forced to curtail retail service or were unable to supply gas to all customers. These curtailments or outages affected more than 50,000 customers in those states, including the cities of El Paso in Texas; Tucson and Sierra Vista in Arizona; and Hobbs, Ruidoso, Alamogordo, Silver City, Tularosa, La Luz, Taos, Red River, Questa, Española, Bernalillo, and Placitas in New Mexico. In contrast to the relative ease of restoring electric service, restoration of gas service was complicated by the necessity to have LDC crews manually shut off gas meters and then relight pilot lights on site.

Winterization

Generators and natural gas producers suffered severe losses of capacity despite having received accurate forecasts of the storm. Entities in both categories report having winterization procedures in place. However, the poor performance of many of these generating units and wells suggests that these procedures were either inadequate or were not adequately followed.

The experiences of 1989 are instructive, particularly on the electric side. In that year, as in 2011, cold weather caused many generators to trip, derate, or fail to start. The PUCT investigated the occurrence and issued a number of recommendations aimed at improving winterization on the part of the generators. These recommendations were not mandatory, and over the course of time implementation lapsed. Many of the generators that experienced outages in 1989 failed again in 2011.

On the gas side, producers experienced production declines in all of the recent prior cold weather events. While these declines rarely led to any significant curtailments, electric generators in 2003 did experience, as a result of gas shortages, widespread derates and in some cases outright unit failure. It is reasonable to assume from this pattern that the level of winterization put in place by producers is not capable of withstanding unusually cold temperatures.

While extreme cold weather events are obviously not as common in the Southwest as elsewhere, they do occur every few years. And when they do, the cost in terms of dollars and human hardship is considerable. The question of what to do about it is not an easy one to answer, as all preventative measures entail some cost. However, in many cases, the needed fixes would not be unduly expensive. Indeed, many utilities have already undertaken improvements in light of their experiences during the February event. This report makes a number of recommendations that the task force believes are both reasonable economically and which would substantially reduce the risk of blackouts and natural gas curtailments during the next extreme cold weather event that hits the Southwest.

Electric and Gas Interdependency

The report also addresses the interdependency of the electric and natural gas industries. Utilities are becoming increasingly reliant on gas-fired generation, in large part because shale production has dramatically reduced the cost of gas. Likewise, compressors used in the gas industry are more likely than in the past to be powered with electricity, rather than gas. As a result, deficiencies in the supply of either electricity or natural gas affect not only consumers of that commodity, but of the other commodity as well.

Gas shortages were not a significant cause of the electric generator outages experienced during the February 2011 event, nor were rolling blackouts a primary cause of the production declines at the wellhead. Both, however, contributed to the problem, and in the case of natural gas shortfalls in the Permian and Fort Worth Basins, approximately a quarter of the decline was attributed to rolling blackouts or customer curtailments affecting producers.

The report explores some of the issues relating to the effects of shortages of one commodity on the other, including the question of whether gas production and processing facilities should be deemed "human needs" customers and thus exempted or given special consideration for purposes of electric load shedding. However, any resolution of the many issues arising from electric and natural gas interdependency must be informed by an examination of more than one cold weather event in one part of the country. For that reason, the report does not offer specific recommendations in this area, but urges regulatory and industry bodies to explore solutions to the many interdependency problems which are likely to remain of concern in the future.

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III. The Electric and Natural Gas Industries

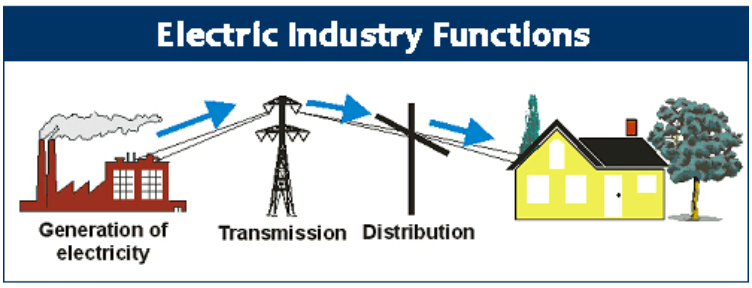
Electricity and natural gas are two of the most essential commodities for the conduct of modern life. However, the industries that produce electricity and natural gas and deliver these commodities from their points of production to consumers differ greatly from one another, as do the regulatory schemes governing them. This section provides an overview of the electric and natural gas industries, their market structures, and the regulatory authorities under which they operate, focusing particularly on the southwest region of the country. This background will be useful in understanding the causes of the outages and curtailments experienced during the first week of February 2011, the actions taken by the entities affected, and the recommendations the task force is suggesting to prevent a recurrence of the widespread service disruptions.

A. The Electric Industry

This subsection describes the structures under which electricity is generated and transmitted, the regulation of electric service providers, and the characteristics of the electricity markets found in the Southwest. A more detailed description of how electricity is produced, transmitted and delivered can be found in the appendix entitled "Electricity: How it is Generated and Distributed."

Overview of Electric Power Production and Delivery

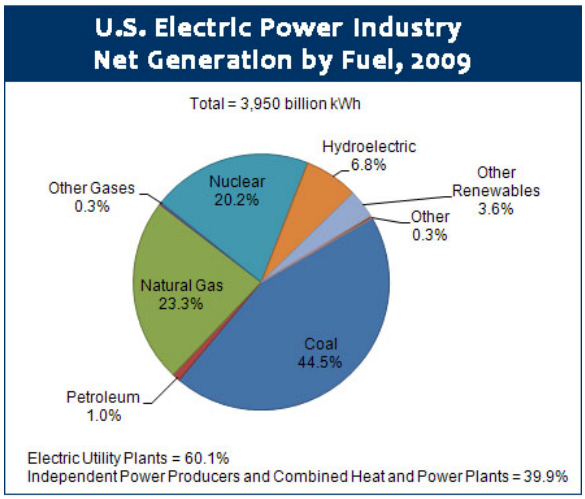
The electric power industry is comprised of three separate functions: generation, transmission, and distribution. These are depicted in the figure below.



Source: EIA

Most of the power produced in the United States uses coal, natural gas, or nuclear fission as the energy source to produce steam or other hot combustion gas that turns a turbine and thereby creates electricity. The figure below shows the fuel source percentages for electricity produced in the US in 2009, with the majority of electricity coming from fossil fuels (coal and natural gas totaling a 68

percent share). While wind and solar energy have experienced fairly rapid growth over the past several years, renewable fuels (including hydroelectric generation's seven percent share) accounted for about 11 percent of the electricity generated in the United States in that year. Wind generation is more common in the Southwest than in most other regions; its share of total generation is about 3.8 percent.[1]



Generating units typically fall into three categories: base load, intermediate, and peaking units. Base load units, usually coal-fired or nuclear, have a relatively low operating cost and have fairly slow or expensive ramping rates.[2] These units are seldom cycled on and off, and are instead scheduled to cover the base levels of projected load. Peaking units, which are generally gas-fired, can be started up very quickly and have relatively expensive operating costs. Accordingly, they are generally last in the dispatch order and are used to cover seasonal (and sometimes daily) peak load levels. Intermediate plants fall somewhere in between base load and peaking with respect to operating characteristics, start-up times, and capacity factors.[3]

Generating plants produce power at a relatively low voltage level, so the power must be "stepped up" to a higher voltage in order to be more efficiently

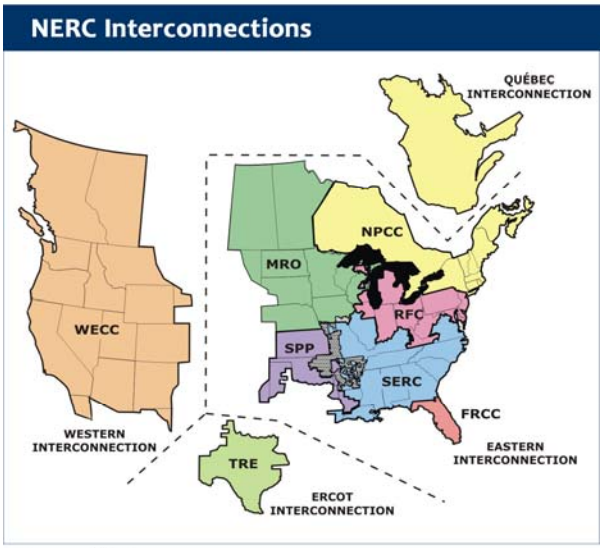
[1] United States Energy Information Administration (EIA), *Electric Power Monthly*, Table 6 - Total Renewable Net Generation by Energy Source and State, 2009 (released August 2010) and *Electric Power Annual*, Figure 2.1 – U.S. Electric Industry Net Generation by State, 2009 (released November 2010, revised January and April 2011).

[2] "Ramping" refers to the generator's ability to produce more or less power on request.

[3] "Capacity factor" refers to the ratio of average generation to the capacity rating of an electric generating unit for a specified period (expressed as a percentage).

transmitted to its ultimate point of use. Energy is carried at these higher voltages over transmission lines (usually between 138 kV and 765 kV) to load centers, where voltage is then stepped back down to a distribution level for delivery to end-use customers. While distribution lines are generally considered to be those operating at 69 kV and below,[4] some industrial end-use customers may take service at transmission-level or intermediate-level voltages.

Virtually all of the transmission system in the continental United States is operated as an alternating current (AC) system, although the West and a few other areas make use of some direct current (DC) lines for long-haul transportation of power or for system stability. DC ties are also used to provide limited connectivity between the three electrically independent grids currently found in the United States: (1) the Eastern Interconnection, which covers the eastern two-thirds of the United States and contiguous parts of Canada; (2) the Western Interconnection, which covers the western third of the United States, the Canadian provinces of Alberta and British Columbia, and a small portion of Baja California Norte, Mexico; and (3) ERCOT, which covers most of the state of Texas. (A fourth interconnection, the Quebec Interconnection, is located wholly in Canada.)



Source: NERC

[4] The bulk electric system, which constitutes transmission as opposed to distribution, has been described by FERC as those facilities operating at 100 kV or above except for defined radial facilities, with exemptions for those facilities not necessary for operating the interconnected transmission network. *Revision to Electric Reliability Organization Definition of Bulk Electric System*, Order No. 743, 75 Fed. Reg. 72,910 (Nov. 26, 2010), 133 FERC ¶ 61,150 (2010), *order on reh'g*, Order No. 743-A, 134 FERC ¶ 61,210 (2011).

Within each interconnection, power generally flows freely across the entire grid. An imbalance of generation versus demand that is significant enough to cause instability on one utility's system can ultimately affect the stability of all systems operating in that interconnection.[5]

Evolution and Regulation of the Electric Industry

Under part II of the Federal Power Act,[6] FERC has jurisdiction over the rates, terms and conditions of wholesale sales of electric energy and transmission services in interstate commerce that are provided by jurisdictional entities (which generally excludes electric cooperatives and federal or state entities, including municipal utilities). Notably, wholesale electric energy sales and transmission services provided wholly within ERCOT are not considered to be interstate under the Federal Power Act, and are therefore not subject to FERC jurisdiction. States generally regulate retail sales of electric energy and distribution services, although publicly-owned and member-owned entities (such as electric cooperatives and municipal utilities) may be exempt from direct state regulatory oversight. In Texas, the PUCT exercises jurisdiction over wholesale sales of energy and the provision of transmission services wholly within the ERCOT footprint.

Historically, all three of the electric sector functions (generation, transmission, and distribution) were provided by one vertically-integrated utility, which was typically granted a monopoly franchise by states to serve retail customers within a given geographic area. While wholesale sales or exchanges of electric energy did occur between utilities, utilities historically planned their systems, both generation and transmission, to serve their own native peak load requirements.

Entities Providing Electric Services in the United States

The electric sector in the United States is made up of a variety of entities, including investor-owned utilities, publicly-owned utilities (including municipal utilities, public utility districts, and irrigation districts), member-owned utilities (generally rural electric cooperatives), Federal electric utilities, and

(cont'd)

[5] *See generally* U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations at 5-10 (April 2004) (2003 Blackout Report), *available at* http://www.ferc.gov/industries/electric/indus-act/reliability/blackout.asp#skipnav (last visited Aug. 2, 2011).

[6] 16 U.S.C. § 824 et seq.

independent power producers. Investor-owned utilities (IOUs) are private entities that were historically vertically-integrated, *i.e.*, owning generation, transmission and distribution assets. However, in states with restructured electric markets, many IOUs were required or strongly incentivized to divest or spin-off their generation assets, and now own only transmission and distribution assets as part of the utility company. Based on 2007 data from the United States Energy Information Administration, IOUs serve about 71 percent of the retail customers in the country. Publicly-owned electric utilities and electric cooperatives have generally been exempted from state restructuring initiatives, and have not been required to offer customer choice or to divest generation assets. There are approximately 2,000 publicly-owned utilities in the United States (which own about 9 percent of the installed generating capacity) and over 880 electric cooperatives (which own approximately 4 percent of the installed capacity).

Since the 1970s, a number of changes occurred to alter this traditional, vertically-integrated model. In 1978, Congress created a class of non-utility generators called qualifying facilities (QFs), and in 1992 created a class of independent generators called Exempt Wholesale Generators. This legislation opened the door not only for independent owners to develop generating plants in multiple regions, but also for utilities to develop generating plants in regions outside their service territory.[7]

FERC took a number of steps to further encourage the development of a competitive wholesale market for generation, including by (1) authorizing generation owners to sell wholesale power at market rates if they can demonstrate that they lacked market power in the relevant market; and (2) requiring transmitting utilities to provide open access transmission service for the delivery of power to wholesale customers on terms and conditions comparable to the transmission service the utilities provided themselves in serving their native load customers.[8]

[7] Energy Policy Act of 1992, Pub. L. No. 102, 486.

[8] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part*

FERC also encouraged the formation of Independent System Operators (ISOs)[9] and Regional Transmission Organizations (RTOs).[10] ISOs/RTOs serve a number of functions critical to operation of the wholesale market within a given region, including control and operation of the transmission grid, operation of real-time and day-ahead markets, and transmission system planning.[11] Not all regions in the United States have adopted an ISO/RTO structure, although they may rely on other power pool structures. The map below shows the footprint of the nine ISOs or RTOs currently operating in the US and Canada.

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sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.* New York v. FERC, 535 U.S. 1 (2002) (Order No. 888).

[9] ISOs grew out of Order No. 888, issued in 1996, as a means of satisfying FERC's requirement that jurisdictional utilities provide non-discriminatory access to transmission services. Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,730; and *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v.* FERC, 272 F.3d 607 (D.C. Cir. 2001).

[10] In 1999, as part of Order No. 2000, FERC created and sought to encourage the voluntary formation of Regional Transmission Organizations to oversee electric transmission and ancillary services and transmission planning services across a broader territory. ISOs and RTOs perform similar functions, but RTOs are only recognized as such if they meet FERC's minimum characteristics and minimum functions as set out in Order No. 2000. In addition, ISOs tend to be smaller in geographic size, or are not subject to FERC jurisdiction. *See* "The Value of Independent Regional Grid Operators: A Report by the ISO/RTO Council," *available at* <http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/Value_of_Independent_Regional_Grid_Operators.pdf>. Order 2000: *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[11] *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,730 (1996).

Regional Transmission Organizations/Independent System Operators

In markets where an ISO/RTO has been approved, the ISO/RTO is generally responsible for dispatching generating units based on hourly energy prices offered by the generation owner or other energy marketer. Initially, these competitive wholesale markets were structured to reflect only energy products and ancillary services,[12] with no compensation for the provision of capacity[13] and no corresponding obligation on the part of generators to offer into a specific market.[14] Many of the markets have undergone modifications over time, including

[12] Ancillary services support the reliable operation of the transmission system as it moves electricity from generating sources to retail customers, and in RTO or ISO-based markets are generally procured through a mechanism or market separate from the energy market. Ancillary services typically include regulation, synchronized or spinning reserves, non-spinning reserves, and black-start services. Among ERCOT's various categories of ancillary services are responsive reserve service (RRS) and non-spinning reserve service (NSRS). RRS are operating reserves intended to help control the frequency of the system. NSRS are reserves intended to cover the uncertainties in forecasting load and wind power output.

[13] Capacity (or installed capacity) refers in this context to the maximum kW or MW of output offered into a capacity market and required to be available except as otherwise provided by the relevant market rules. Payments by load serving entities for capacity are made regardless of whether energy is actually provided, as long as the relevant availability requirements are met. Penalties are generally imposed if a supplier fails to meet the availability requirements or otherwise provide energy when called upon.

[14] After an offer is accepted in a given energy or ancillary services market, the generator or its marketer has the obligation to deliver the energy or to cover the real-time cost of replacement if the generator experiences a forced outage or derate. In addition, even in an energy-only market, certain generators that are deemed essential for reliability (often referred to as reliability must-run generators or RMRs), are paid an amount above the base energy payments to ensure that the unit remains operational and available; these generators are subject to some form of penalty if the unit is not available as provided for under the market rules or specific RMR contract.

implementation of day-ahead markets, virtual bidding,[15] nodal pricing,[16] and separate capacity markets.

Energy-Only Markets versus Capacity Markets

In an energy-only market, load serving entities purchase energy on an hourly basis (even if secured or scheduled on a day-ahead or forward basis), and are generally also required to cover minimum ancillary services requirements, including voltage support, regulation, and spinning or non-spinning reserves. These load-serving entities are not obligated to secure capacity to cover their projected peak loads going forward, and generators can only recover their capital costs through payments for hourly energy and ancillary services.

In markets with capacity-based payments, load serving entities are responsible for procuring capacity (including adequate reserves) to cover their peak loads. In the Northeast, capacity prices are set through forward capacity markets, and while generators receive the benefit of a more predictable revenue stream, they must also accept certain obligations to ensure that their unit is available and offered into the energy market when needed, or face penalties for failure to do so.

Reliability Oversight by FERC, NERC and Regional Entities

In 1968, following the extensive 1965 blackout in the Eastern United States and Canada, members of the electric utility industry formed a voluntary council (NERC)[17] to coordinate regional planning for the industry and develop operating

[15] A form of transaction where buyers and sellers place trades based on differences between day-ahead prices and real-time prices. Virtual bidding is intended to improve market efficiency as real-time and day-ahead prices converge.

[16] Nodal pricing uses the locational marginal price (LMP, or the cost of supplying the next megawatt of load) at each specific electric location or bus. In a completely unconstrained system, the nodal price will be the same at each node on the system. When transmission constraints occur, the nodal price will reflect the cost of dispatching generating units out of economic merit order in order to serve load within the constrained area. Nodal pricing allows for separate energy prices at each bus, while zonal pricing sets a locational price for much larger, pre-established zones.

[17] The council was originally named the National Electric Reliability Council, but the name was later changed to North American Electric Reliability Council to reflect Canadian

guides and voluntary standards and practices to protect the reliability of the interconnected system.[18] While efforts were undertaken in the 1990s to require adherence to NERC reliability policies and guidelines, mandatory reliability standards were not adopted in the United States until Congress passed the Energy Policy Act of 2005 (EPAct 2005). That act required FERC to certify an independent Electric Reliability Organization (ERO) tasked with developing and enforcing such mandatory reliability standards.[19]

Pursuant to EPAct 2005, FERC certified NERC as the ERO on July 20, 2006.[20] Under implementation procedures adopted by FERC, NERC is permitted to delegate a portion of its responsibilities for enforcement and for regional standards development to Regional Entities, which NERC in turn oversees. NERC has provided such delegated authority to eight Regional Entities in the United States and Canada, each of which has primary authority for enforcement in the regions shown below.[21]

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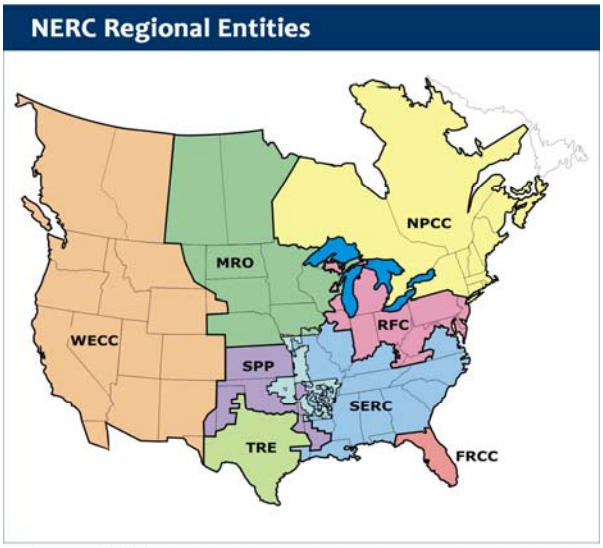
member participation, and changed again to North American Electric Reliability Corporation in 2007 to reflect its new role as the independent Electric Reliability Organization. *See NERC Company Overview: History*, http://www.nerc.com/page.php?cid=1|7|11.

[18] Responsibility for the voluntary standards and operating guidelines was originally given to the North American Power Systems Interconnection Committee (NAPSIC, formed earlier in the 1960s). NAPSIC later became part of NERC. *Id.*

[19] *See* Energy Policy Act of 2005, Pub. L. No. 109-58. The renewed efforts to adopt mandatory reliability standards that prompted this section of the Energy Policy Act came in response to the Northeastern blackout of August 14, 2003, and to the recommendations made in a report prepared by a joint US-Canada task force that reviewed the causes of the blackout. *2003 Blackout Report* at 3 (adopting as its first recommendation: "Make reliability standards mandatory and enforceable, with penalties for noncompliance.")

[20] *N. Am. Elec. Reliability Corp*. 116 FERC ¶ 61,062 (2006).

[21] The eight Regional Entities operating under delegated authority from NERC are Florida Reliability Coordinating Council, Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Reliability Corporation, Southwest Power Pool Regional Entity, Texas Reliability Entity, and Western Electric Coordinating Council.



Source: NERC

Under Section 215 of the Federal Power Act, NERC must submit its proposed Reliability Standards to FERC for approval before they may become mandatory and enforceable. In order to approve a Reliability Standard, FERC must find that it is just, reasonable, not unduly discriminatory or preferential, and in the public interest, after giving due weight to the technical expertise of the ERO.[22] In addition, while the ERO has the authority to propose a penalty for violation of a Reliability Standard following notice and opportunity for a hearing, that penalty may only take effect after it has been filed with FERC. FERC can exercise the option to review, set aside, or modify the penalty, on its own motion or on application by the entity subject to the proposed penalty.[23] FERC also has the authority, on its own motion or on complaint, to order compliance with a Reliability Standard or to impose a penalty for violation of a Reliability Standard.[24]

In Order No. 693, FERC approved the first set of 83 Reliability Standards, which became enforceable on June 18, 2007.[25] NERC maintains a Compliance

[22] 16 U.S.C. § 824o(d)(1) and (2).

[23] *Id*. at § 824o(e)(1) and (2).

[24] *Id.* at § 824o(e)(3).

[25] NERC and the Regional Entities may assess penalties for non-compliance with the Reliability Standards. In order for such a penalty to take effect, NERC must file a notice of penalty with FERC. Each penalty determination is subject to FERC review. In the absence of an application for review or action by FERC, each penalty filed by NERC is affirmed by operation of law after 30 days.

Registry that identifies all entities subject to compliance with the approved Reliability Standards. Users, owners and operators of the bulk power system are required to register with NERC under the appropriate functional categories, and each Reliability Standard designates each category of entity to which it applies. Currently, there are over 1900 registered entities subject to the Reliability Standards (a number of entities are counted more than once as they are registered under more than one category). The categories of registered entities are set out in the appendix entitled "Categories of NERC Registered Entities."

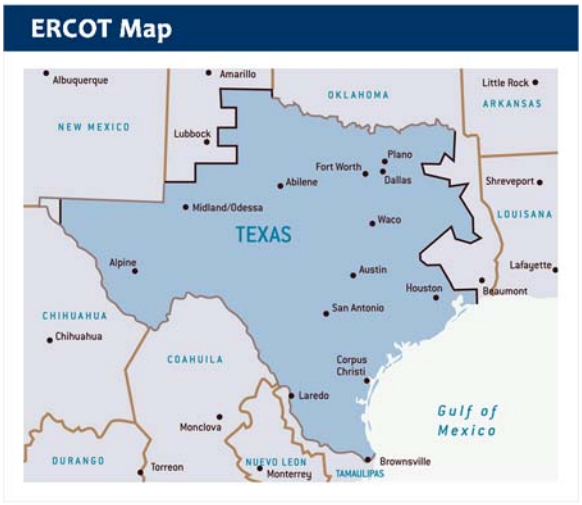
Registered entities are required to report the occurrence of defined bulk power system disturbances and unusual occurrences to the appropriate Regional Entity and to NERC. The Regional Entity and/or NERC in turn undertakes various levels of analysis to determine the causes of the events, assure tracking of corrective actions to prevent recurrence, gather information needed to assess compliance, and provide lessons learned to the industry. The event analysis process also provides input for training and education, reliability trend analysis efforts and Reliability Standards development, all of which support continued reliability improvement. Under NERC's field trial of its event analysis program, the February 2 and February 3 event was classified as a category 4 event due to the overall significance and impact of the event (loss of over 5,000 MW but less than 10,000 MW of load or generation). Based on the scope of the needed analysis, and the fact that it impacted multiple regions, NERC determined that the event review should be coordinated at the NERC level.

Southwest Electricity Markets, Pools and Reserve Sharing Groups

The Southwest contains two ISO/RTOs (ERCOT and SPP), and a number of vertically integrated utilities that are located within the WECC region. These are described below.

ERCOT

The Electric Reliability Council of Texas (ERCOT) is an ISO that covers approximately seventy-five percent of the landmass within Texas, excluding the El Paso area, part of the northern panhandle, and part of the region east of Houston. ERCOT manages access to the transmission system within its footprint and operates the Texas energy and ancillary services markets (it does not have a capacity market).



Source: ERCOT

ERCOT schedules power over 40,500 miles of transmission lines and is responsible for the dispatch of more than 550 generating units.[26] It was founded in 1970 as one of the NERC regional reliability coordination councils, and is currently the registered balancing authority for 85 percent of the electric load in Texas.[27] When it became an ISO in 1996 it undertook a number of new responsibilities, including operation of the wholesale competitive electricity market. When Texas restructured its electric industry in 2002, implementing customer choice for most retail customers and requiring divestiture of generation by IOUs, ERCOT also undertook administration of customer switching for those retail customers in Texas that can choose their electric service provider.

ERCOT is a summer-peaking region, and experienced its highest peak demand to date (68,294 MW) on August 3, 2011. Generation in ERCOT is fairly diverse in terms of fuel sources. Natural gas represented the highest percentage of installed capacity in 2009 (at 59 percent), but coal and nuclear power combined to provide over 50 percent of the energy produced for that year. [28]

ERCOT operates as a functionally separate interconnection, although it has five asynchronous ties with other interconnections.[29] Three of the ties allow

[26] For ERCOT background, *see generally* ERCOT 2009 Annual Report, *available at* http://www.ercot.com/content/news/presentations/2010/2009%20ERCOT%20Annual%20Report.pdf.

[27] ERCOT is also registered in NERC's Compliance Registry as an interchange authority, planning authority, reliability coordinator, resource planner, and transmission service provider. In addition, it also partners with other transmission operators in Texas and in that capacity is listed as a "coordinated functional registration."

exchanges with Mexico (through the Comisión Federal de Electricidad, or CFE): the Laredo Variable Frequency Tie, the South Tie (also called Eagle Pass), and the Railroad Tie, the latter located near McAllen, Texas. Two of the ties allow exchanges with the Eastern Interconnection through SPP: the North Tie, located near Oklaunion, Texas, and the East Tie, located near Mt. Pleasant, Texas. The maximum amount of energy that can be imported on all the ties is 1090 MW (approximately 2.3 percent of ERCOT's 2010/2011 forecasted winter peak), with most of that attributable to the ties to the Eastern Interconnection.[30]

ERCOT originally employed a zonal market design, under which the region was divided into pricing zones and all generators within a zone received the same price for the power they provided. It shifted to a nodal market design in December 2010, under which prices are assessed at points (nodes) where electricity enters or leaves the grid. The settlement price at each node is referred to as the locational marginal price (LMP). A nodal market design allows for more precise price signals and greater dispatch efficiencies than a zonal market design, and permits direct assignment of congestion costs through the more granular locational marginal prices.

Under its previous zonal market, ERCOT had no day-ahead energy market (although ancillary services were procured on a day-ahead basis to ensure sufficient capacity would be available). Under its current nodal market, ERCOT has a day-ahead energy market, which is co-optimized with ancillary services.

ERCOT has an energy-only market, as opposed to both an energy market and a capacity market. Capacity markets are used to address resource adequacy concerns; typically, a planning reserve margin is established to maintain reliability goals, and the ISO/RTO imposes capacity obligations on load-serving entities that are met through bilateral contracting or a centralized capacity market. In contrast, an energy-only market relies on energy price signals to spur investment in new generation. Thus, by design, ERCOT's energy-only market would be expected to

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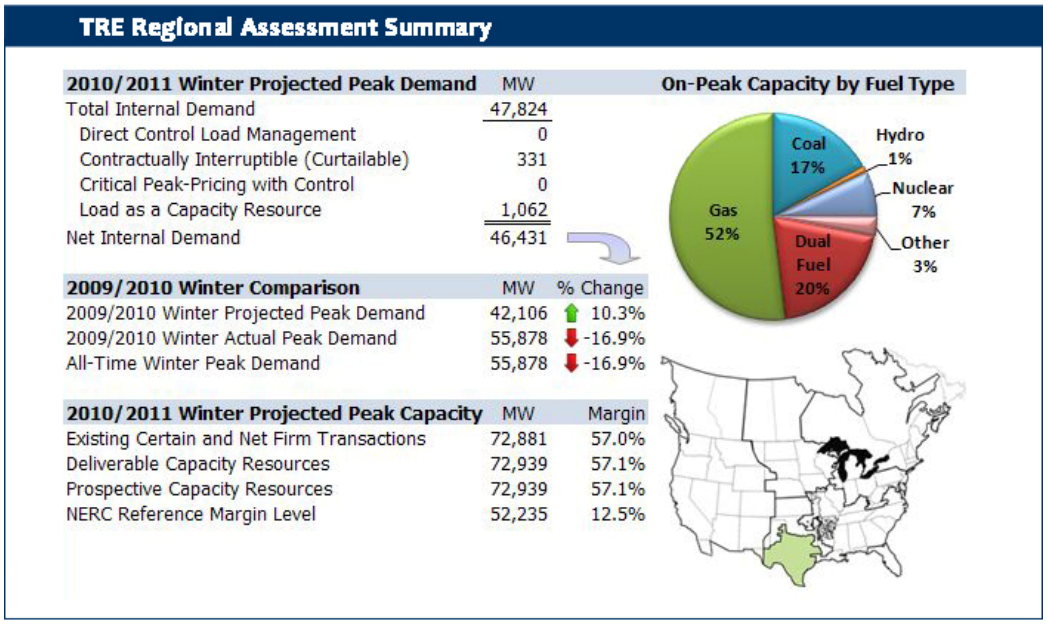
[28] ERCOT reported the following percentage fuel mix of installed capacity in 2009, in declining order: (1) natural gas, 59 percent; (2) coal, 22 percent; (3) wind, 11 percent; (4) nuclear, 6 percent; and (5) hydroelectric and biomass, 2 percent. ERCOT reported the following percentages for energy produced for 2009: (1) natural gas, 42 percent; (2) coal, 37 percent; (3) nuclear, 14 percent (4) wind, 6 percent; and (5) hydroelectric and biomass, 1 percent. ERCOT 2009 Annual Report at 2.

[29] Four are DC interties and one is a variable frequency transformer (VFT) inter-tie.

[30] The maximum MW that can be imported on each of the ties (actual limits may vary based on real-time conditions) is as follows: North, 210 MW; East, 600 MW; South/Eagle Pass, 30 MW; Railroad, 150 MW; and Laredo, 100 MW.

result in higher prices during times of scarcity and produce more volatile prices in general than do dual energy and capacity markets. These price signals are intended to encourage investment in energy resources, such as new generation plants, demand response, and energy efficiency, to meet growing demand.

NERC's regional assessment summary for TRE, which includes the ERCOT control area, for the winter of 2010/2011 is presented in the following chart.[31]



Source: NERC Winter Reliability Assessment 2010/2011

WECC Region and Southwest Reserve Sharing Group

WECC is the largest geographically of the eight NERC Regional Entities, with responsibility for coordinating and promoting system reliability throughout the Western Interconnection. WECC's service territory covers Alberta and British Columbia, the northern part of Baja California in Mexico, and all the states in between, constituting an area of about 1.8 million square miles.

WECC's bulk power system generally transfers energy over long transmission lines from remotely located generators to load centers. The lack of redundant transmission facilities demands a high level of operational scrutiny in order to maintain correct voltages and power flows on the many stability limited transmission paths that exist in the Western Interconnection.

[31] NERC 2010/2011 Winter Reliability Assessment, *available at* http://www.nerc.com/files/2010_Winter_Assessment_Final_Posted.pdf.

WECC has registered 34 balancing authorities;[32] 52 transmission operators, and 3 reserve sharing groups. The California Independent System Operator (CAISO) is the only balancing authority in the Western Interconnection that operates as an ISO or RTO.

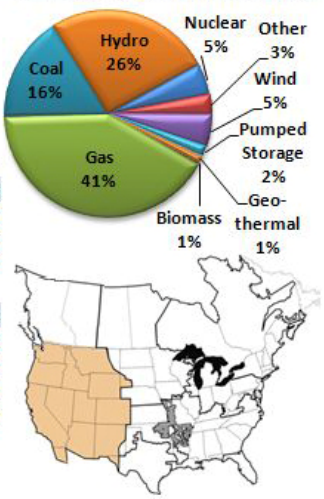
NERC's regional assessment summary for WECC for the winter of 2010/2011 is presented in the following chart.[33]

WECC Regional Assessment Summary

2010/2011 Winter Projected Peak Demand	MW
Total Internal Demand	104,424
Direct Control Load Management	571
Contractually Interruptible (Curtailable)	1,814
Critical Peak-Pricing with Control	25
Load as a Capacity Resource	30
Net Internal Demand	101,984

2009/2010 Winter Comparison	MW	% Change
2009/2010 Winter Projected Peak Demand	108,132	-5.7%
2009/2010 Winter Actual Peak Demand	109,565	-6.9%
All-Time Winter Peak Demand	113,605	-10.2%

2010/2011 Winter Projected Peak Capacity	MW	Margin
Existing Certain and Net Firm Transactions	157,290	54.2%
Deliverable Capacity Resources	159,282	56.2%
Prospective Capacity Resources	159,282	56.2%
NERC Reference Margin Level	116,874	14.6%



Source: NERC Winter Reliability Assessment 2010/2011

Two of the entities that experienced rolling blackouts during the February event, SRP and EPE, are located in the WECC region. SRP, one of Arizona's largest utilities, is vertically integrated and a subdivision of the State of Arizona. Serving over 933,500 retail customers, SRP's eleven main generating stations, combined with numerous smaller facilities, have a peak retail load of over 6400 MW, and serve a 2,900 square mile area. SRP is registered with NERC for all bulk power system functions except interchange authority, reliability coordinator, and reserve sharing group.

[32] NERC defines "balancing authority" as the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within the BA area, and supports interconnection frequency in real-time.

[33] NERC 2010/2011 Winter Reliability Assessment.

EPE is a vertically integrated electric utility providing generation, transmission, and distribution service in west Texas and southern New Mexico. EPE serves approximately 372,000 customers over a 10,000 square mile service territory via five major generating stations, including three stations local to El Paso, Texas. It has a native peak load of 1616 MW. Like SRP, EPE is registered with NERC for all bulk power system functions except interchange authority, reliability coordinator, and reserve sharing group.

Both SRP and EPE participate in the Southwest Reserve Sharing Group (SRSG), which provides for the sharing of contingency reserves among its participants pursuant to a Participation Agreement. SRSG was formed in 1998 as the successor to an earlier pool, and has participants in Arizona, New Mexico, southern Nevada, part of southern California and El Paso, Texas. SRSG is a NERC Registered Entity, and administers certain requirements related to disturbance control and emergency operations standards. Its participants are obligated to carry reserves in accordance with a contractual formula, and to provide power within a certain time frame to other participants experiencing a disturbance on their systems.

Southwest Power Pool

SPP is both an RTO and a NERC Regional Entity responsible for the enforcement of Reliability Standards within its region. SPP had its origins in 1941, when eleven regional power companies formed the pool in order to ensure sufficient electric service to aluminum plants needed for the war effort. The pool remained intact after the war and was a founding member of NERC in 1968. SPP implemented operating reserve sharing arrangements among its members in 1991, and became a FERC-approved RTO in 2004.

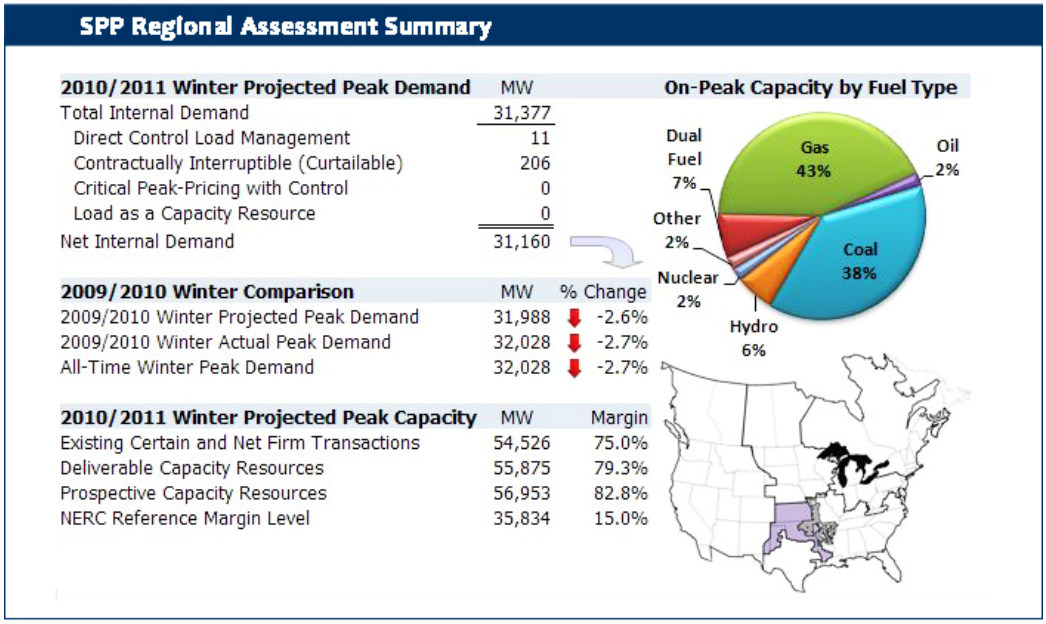
SPP covers a 370,000 mile area that includes all or portions of nine states: Nebraska, Kansas, Oklahoma, Missouri, Arkansas, Louisiana, Texas, New Mexico, and Mississippi.[34] SPP operates 48,930 miles of transmission lines, and has a coincident peak demand within its reliability coordinator[35] footprint of approximately 55,000 MW.

[34] SPP actually has five "footprints," with differing membership and oversight functions, as (1) a NERC Regional Entity; (2) a reserve sharing group; (3) a reliability coordinator area (29 balancing authorities and transmission owners, including certain balancing authorities in SERC and the Midwest Reliability Organization); (4) an RTO (with 15 balancing authorities); and (5) an energy imbalance services (EIS) market region (with 15 balancing authorities). *See* http://www.spp.org/section.asp?pageID=28 (last visited Aug. 2, 2011).

[35] NERC defines "reliability coordinator" as the entity that is the highest level of authority responsible for the reliable operation of the bulk power system, has the wide area view

At present, SPP's market operations are relatively limited, currently allowing participants to buy and sell energy in real time and to settle out any energy scheduling imbalances based on the real-time market price. SPP does not currently operate a separate market for reserves but is working to implement a new integrated marketplace that includes a day-ahead energy and operating reserves market.[36]

NERC's regional assessment summary for SPP for the winter of 2010/2011 is presented in the following chart.[37]



Source: NERC Winter Reliability Assessment 2010/2011

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of the bulk power system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The RC has the purview that is broad enough to enable the calculation of interconnection reliability operating limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.

[36] Unlike California, Texas, and the Northeast, most of the states SPP covers have not undertaken a broad restructuring of the electric industry through retail access and/or mandatory unbundling of generation from transmission and distribution. Accordingly, most utilities operating within SPP's footprint still supply a large portion of their customers' electricity needs through their own generation and do not need to access the market to do so.

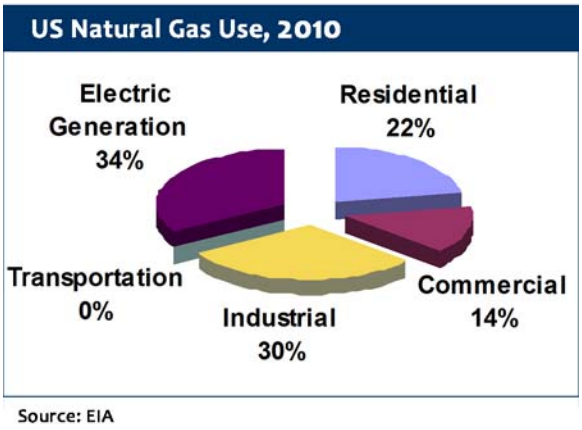
[37] NERC 2010/2011 Winter Reliability Assessment.

B. The Natural Gas Industry

This subsection provides an overview of the manner in which natural gas is produced and delivered, the jurisdictional structures applicable to the industry, and the various producers and pipelines located in the Southwest. A detailed description of the geology and physics of natural gas production and delivery can be found in the appendix entitled "Natural Gas: Production and Distribution."

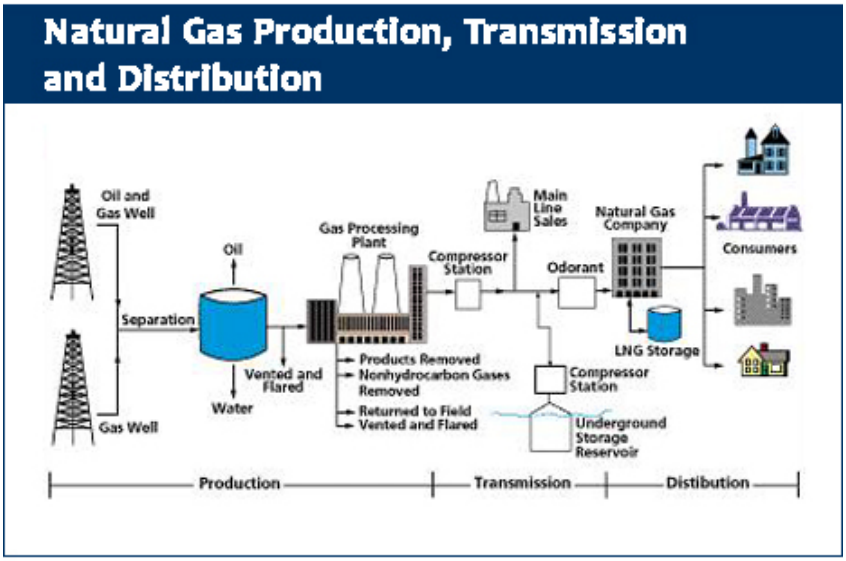
Overview of Natural Gas Production and Delivery

Natural gas is a fossil fuel, formed through the decomposition of organic matter found in underground geological formations. It is a significant source of energy representing 25 percent of the United States energy consumption. In 2010, approximately 22 percent of gas consumption was used for residential heating and cooking, 14 percent for commercial use, 30 percent for industrial processes, 34 percent for electric generation, and less than one percent for transportation.[38]



The delivery framework for natural gas includes production, separation of fluids at or near producing wells, natural gas liquids (NGL) processing, pipeline transmission, storage, and finally distribution by an LDC. The following chart is a simplified schematic of this framework.

[38] EIA, *Natural Gas Consumption by End Use*, http://www.eia. gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm (last visited Aug.27, 2011).

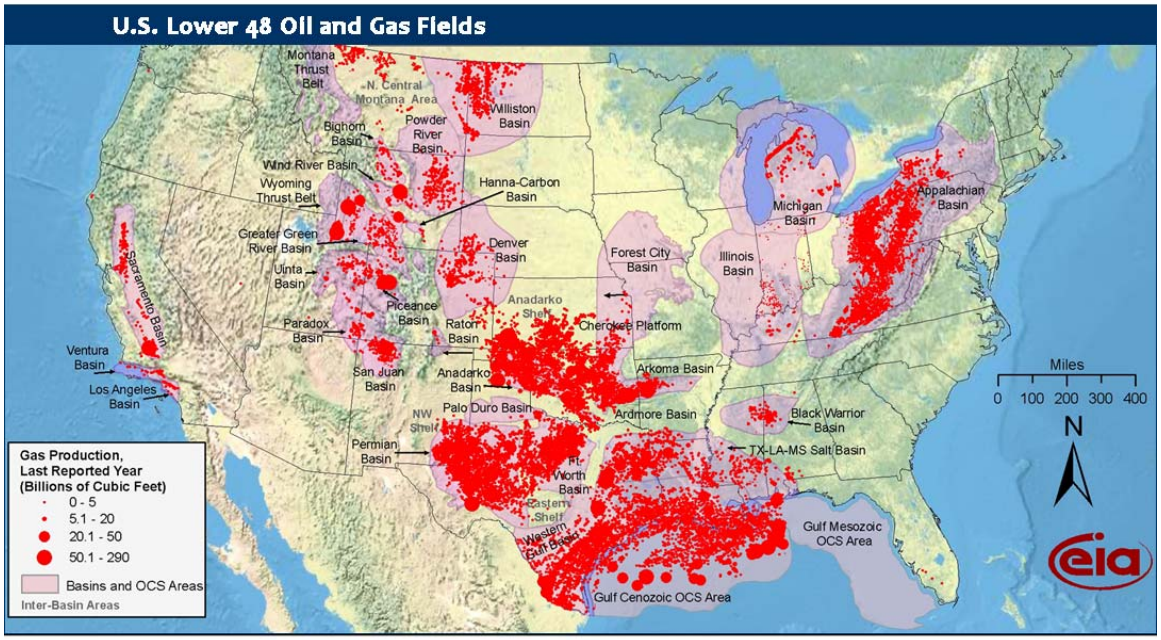


Source: EIA

Natural gas is often produced in locations distant from demand centers. The Energy Information Agency estimates that in 2009 there were 493,100 gas wells in the United States. The majority of these wells were located in the Gulf Coast, Southwest and the Appalachian Basin. The five states with the largest number of wells that year were Texas, 93,507; Pennsylvania, 57,356, West Virginia, 50,602; New Mexico, 44,784, and Oklahoma, 43,600.[39] The following chart shows production basins and the concentration of reported natural gas production.[40]

[39] EIA, *Natural Gas, Number of Producing Wells*, http://www.eia.doe.gov/dnav/ng/ng_prod_wells_s1_a.htm (last visited Aug.2, 2011).

[40] EIA, *Gas Production in Conventional Fields*, http://www.eia.gov/oil_gas/rpd/conventional_gas.pdf (last visited Aug. 2, 2011).



Source: EIA based on data from HPDI, IN Geological Survey, USGS, April 8, 2009

Major oil companies and large independent companies account for a substantial portion of the gas production in the United States. In the first half of 2009, the five largest producers and their daily production were as follows: BP, Inc, 2.33 Bcf per day; Anadarko Petroleum Corporation, 2.33 Bcf per day; XTO Energy, Inc., 2.29 Bcf per day (acquired by ExxonMobil in 2010); Chesapeake Energy Corporation, 2.21 Bcf per day; and Devon Energy Corporation, 2.13 Bcf per day. These producers together accounted for approximately 20 percent of United States production.[41]

In the Southwest, production takes place at the many thousands of wellheads located throughout the basins. The wellhead consists of equipment on top of the well that is used to manage flows of oil and gas, often produced together, arising from the underground formations. The high pressure gas in formations is lighter than air and will often rise on its own through the wellhead to surface pipes. In other gas wells, as well as oil wells with associated natural gas, flow requires lifting equipment. Typical lifting equipment consists of the "horse head" or conventional beam pump. The pumps are recognizable by the distinctive shape of the cable feeding fixture, which resembles a horse's head.[42] They are

[41] Reuters, http://www.reuters.com/article/2009/12/14/xto-exxon-natgas-producers-idUSN1420089920091214; and EIA, http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FPD_mmcf_a.htm. "Bcf" refers to a billion cubic feet.

[42] *Well Completion*, NATURALGAS.ORG, http://www.naturalgas.org/naturalgas/well_completion.asp (last visited Aug. 2, 2011).

often called "pumpjacks" and are seen throughout west Texas and southeastern New Mexico. The following two photographs are of a wellhead and a pumpjack.

Wells and lift equipment are monitored on a daily basis and maintained by oil and gas company employees, who are often referred to as "pumpers" or "gaugers." Their responsibilities include reporting malfunctions and spills, and ensuring that field processing equipment is operational and that production is correctly measured. Onshore gaugers may drive many miles per day to monitor dozens of wells.

Processing Natural Gas

The natural gas used by consumers consists almost entirely of methane. However, produced gas often contains other hydrocarbons such as ethane, propane, butane, pentanes and liquids such as condensates. It may also include water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds. Some field processing occurs near production wells to remove the water and condensates, but complete processing usually occurs at a gas processing plant. Natural gas processing plants remove other hydrocarbons to produce what is known as "pipeline quality" dry natural gas that meets the heating content and other restrictions necessary for the safe operation of pipeline and distribution company facilities. The removed hydrocarbon NGLs are sold separately.

Natural gas is transported to processing plants[43] typically through small-diameter and low-pressure gathering pipelines. There were an estimated 20,552

[43] More than 500 processing plants operated in the United States in 2004 with 166, or over 31 percent, in the state of Texas. EIA, *Natural Gas Processing: The Crucial Link Between Natural Gas Production and Its Transportation to Market*, (Jan. 2006), http://dnr.louisiana.gov/assets/docs/oilgas/productiondata/ngprocess_20060131.pdf.

miles of gathering system pipelines in the United States in 2009.[44]

After gathering and processing, interstate and intrastate transmission pipelines transport gas to LDCs (as well as to directly attached users such as power plants). Within the United States, the pipeline network delivers gas to 65 million residential, commercial, industrial, and power generation customers. It includes at least 210 gas pipeline systems with a total of more than 300,000 miles of transmission pipelines.[45] The pipeline system also includes more than 1,400 compressor stations, 11,000 delivery points, 5,000 receipt points, and 1,400 interconnection points.[46]

Pipeline companies monitor and control gas flow with computerized supervisory control and data acquisition (SCADA) systems, which provide operating status, volume, pressure, and temperature information. In addition to real-time monitoring, the SCADA system may enable a pipeline to start and stop some facilities remotely.[47]

The following map shows the breadth and integrated nature of the natural gas transmission grid.[48]

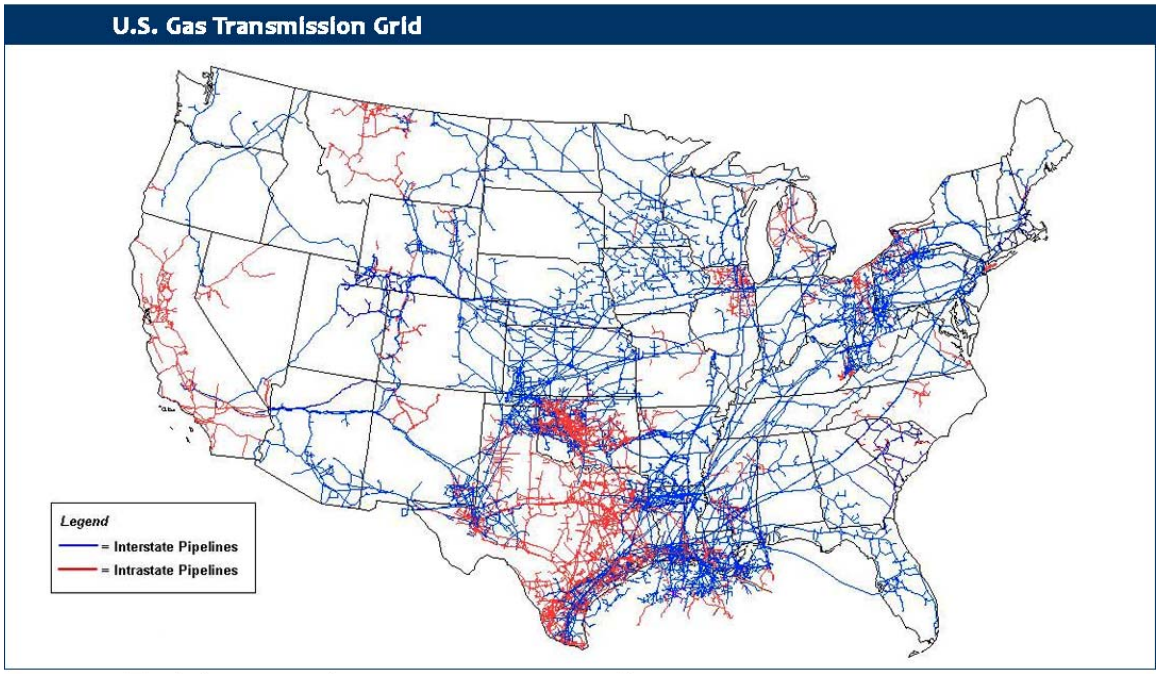
[44] U.S. Dep't of Transp. Pipeline & Hazardous Materials Safety Admin., *Natural Gas Transmission, Gas Distribution, and Hazardous Liquid Pipeline Annual Mileage*, (Jun. 30, 2011), http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc7a8a7e39f2e55cf2031050248a0c/?vgnextoid=036b52edc3c3e110VgnVCM1000001ecb7898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print.

[45] Am. Gas Assn., *About Natural Gas*, http://www.aga.org/Kc/aboutnaturalgas/Pages/default.aspx (last visited Aug. 2, 2011). These pipelines are high pressure systems and operate at 500 to 1,800 psi. The lines are usually 20 inches to 42 inches in diameter. http://www.naturalgas.org/naturalgas/transport.asp.

[46] EIA, *About U.S. Natural Gas Pipelines-Transporting Natural Gas* (June 2007), http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/fullversion.pdf (EIA: About U.S. Natural Gas Pipelines).

[47] INGAA, *Supervisory and Data Acquisition (SCADA)*, http://www.ingaa.org/cms/33/1339/109/134.aspx (last visited Aug. 2, 2011).

[48] EIA: About U.S. Natural Gas Pipelines.



Source: EIA, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

To meet higher gas demand at various times of the year, gas is stored underground in depleted oil and gas reservoirs, aquifers or caverns formed in salt beds.[49] Storage facilities may be interstate and regulated by FERC, or intrastate and non-jurisdictional. There are over 390 underground storage facilities in the United States,[50] of which approximately 205 are under FERC jurisdiction.[51] Depleted oil and gas reservoirs account for 87 percent of the total FERC jurisdictional storage capacity, with salt caverns (3 percent) and aquifers (10 percent) accounting for the rest.[52] A detailed discussion of the types of storage facilities and their characteristics is included in the appendix entitled "Natural Gas Storage."

[49] EIA, *Natural Gas Explained: Delivery and Storage of Natural Gas*, http://www.eia.doe.gov/energyexplained/index.cfm?page=natural_gas_delivery (last updated June 8, 2011).

[50] EIA, *The Basics of Underground Storage*, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/storagebasics/storagebasics.html (last updated Aug. 2004).

[51] http://www.ferc.gov/EventCalendar/Files/20060615103625-A-3-TALKING-PTS.pdf.

[52] http://www.ferc.gov/industries/gas/indus-act/storage/fields.asp.

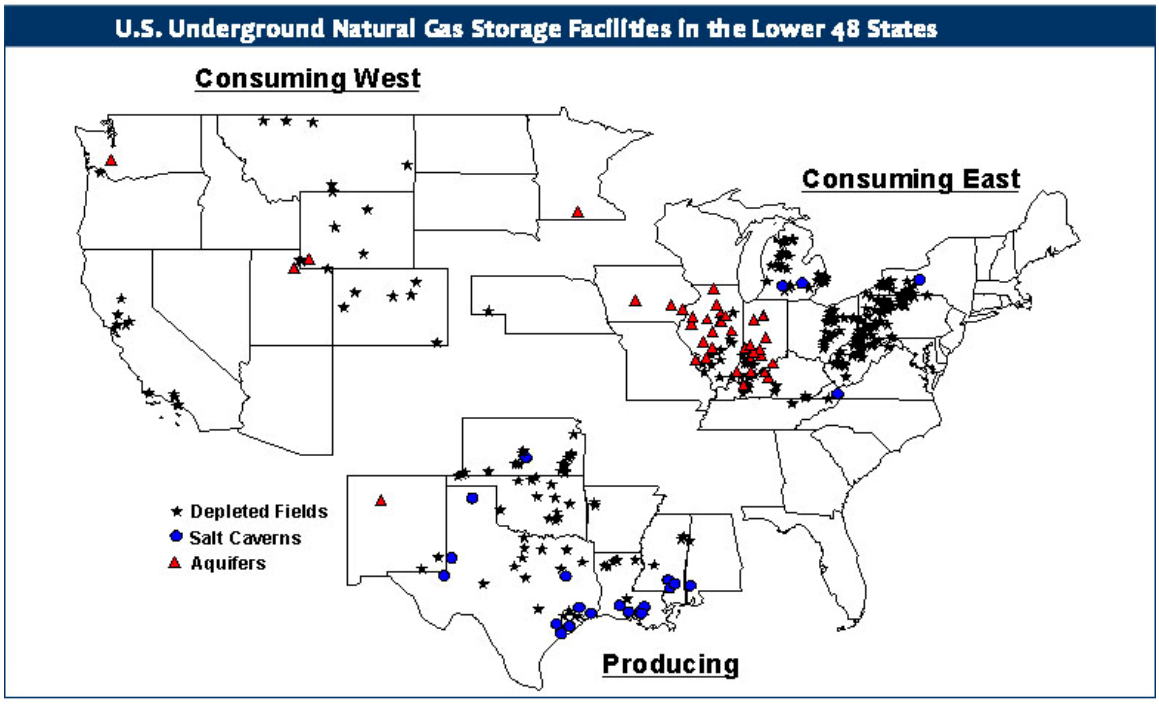
Gas Storage Facilities

- Depleted reservoirs consist of porous and permeable underground formations (average of 1,000 to 5,000 feet deep). The gas is divided into two categories, working or top gas, which can be withdrawn, and cushion or base gas, needed as permanent inventory to maintain adequate reservoir pressure and deliverability rates. Gas is generally withdrawn in the winter heating season and injected during the summer, although the demand for gas in summer months is increasing due to an increase in gas-fired generating plants. This type of storage facility can be used for both system supply and peak day demand.

- Aquifer storage fields are bounded partly or completely by water-bearing rocks. They have a high cushion gas requirement, generally between 50 to 80 percent. They also have high deliverability rates and, similar to depleted reservoirs, gas is generally withdrawn in the winter season and injected in the summer season.

- Salt cavern facilities use solution mining to recover minerals in underground salt deposits (salt domes or salt formations). Salt caverns usually operate with only about 20 to 30 percent cushion gas. Working gas can be recycled multiple times per year. Salt cavern storage has high deliverability and injection capabilities and is used for short peak day deliveries. Salt caverns are more expensive to construct due to the increased capital cost associated with leaching and mining the salt.

The following figure shows the location of United States storage facilities.[53]



Natural Gas Regulation

Natural gas production is not comprehensively regulated, and no government agency monitors daily production activity. However, some aspects of production are subject to regulation; gas-producing states monitor well drilling and permitting, and in Texas, for instance, the TRC has jurisdiction over oil and gas wells located in the state and over persons owning or engaged in drilling oil and gas wells located in the state.[54] Congress deregulated the price on natural gas at the wellhead.[55] FERC does not regulate natural gas producers, but does provide

[53] EIA, *The Basics of Underground Storage*, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/storagebasics/storagebasics.html.

[54] Among the matters covered by the TRC are space and density of drilling; prevention of waste; approval of water flood permits; location exceptions; intrastate pipelines; environmental and safety aspects of production, including well plugging; regulation of the injection of carbon dioxide into reservoirs; and maintenance of well records including logs, maps and production reporting. Jack M. Wilhelm, Texas Land Institute, *What Every Landman Should Know about the Railroad Commission of Texas* (2005), *available at* http://blumtexas.tripod.com/sitebuildercontent/sitebuilderfiles/wilhelm.pdf.

[55] Natural Gas Wellhead Decontrol Act, Pub L. No. 101-60, 103 Stat. 157 (1989).

that producers have not unduly preferential or discriminatory access to transportation on jurisdictional pipelines, and that no undue treatment bias is exercised with respect to transportation services and gas quality standards. Retail natural gas sales to consumers are regulated by state public utility commissions, not by FERC.

FERC's jurisdiction over the transportation of natural gas,[56] which also includes the provision of natural gas storage services, begins when the gas is delivered to an interstate pipeline and continues until the gas is delivered to the wholesale purchaser, absent some intervening transaction which renders the activity exempt from federal jurisdiction under the Natural Gas Act (NGA) or the Natural Gas Policy Act of 1978 (NGPA). While generally the activities of intrastate pipelines and LDCs are exempt from FERC jurisdiction, when those entities engage in the transportation of natural gas in interstate commerce or the wholesale sales for resale of natural gas, their activities are subject to FERC jurisdiction.

FERC's responsibilities include:

- Issuance of certificates of public convenience and necessity to construct and operate interstate pipeline and storage facilities, and oversight of the construction and operation of pipeline facilities at United States points of entry for the import or export of natural gas.
- Regulation of transportation and sales for resale in interstate commerce that are not first sales.
- Regulation of the transportation of natural gas as authorized by the NGPA and the OCSLA (Outer Continental Shelf Lands Act).
- Regulation of liquefied natural gas facility siting.
- Regulation of the abandonment of jurisdictional facilities and services.
- Establishment of rates and terms and conditions for jurisdictional services.

Pipelines publish FERC-approved tariffs that pertain to services, terms of conditions and rates for gas transportation. The North American Energy Standards Board (NAESB) provides business standards for the pipelines in areas such as the scheduling of pipeline transportation.

[56] FERC also has NGA jurisdiction over sales for resale of natural gas that are not deemed first sales. A first sale does not include the sale by an interstate pipeline, intrastate pipeline, or LDC, or affiliate thereof, unless such sale is attributable to volumes of their own production.

Most interstate pipelines no longer offer sales services. The two broad categories of transportation service on an interstate pipeline are firm and interruptible transportation, subject to specified exceptions such as force majeure clauses. (The pipeline companies sell transportation, not the gas itself, which almost always is purchased separately from the producer by the shipper.) Firm transportation is characterized by a reservation of capacity. Shippers customarily pay a charge for the reservation of guaranteed capacity rights on the pipeline and a separate usage charge; pipeline firm rates thus include cost recovery of pipeline facilities in addition to recovery of variable transportation costs such as fuel. Interruptible service rates are usage charges that are derived from the firm service rates. There is no reservation of capacity under interruptible service, and capacity is provided to a shipper only to the extent it is available.[57]

Prior to the deregulation of wellhead gas prices and open access transportation established under Commission Order No. 436 in 1985 and Order No. 636 in 1992, producers typically sold gas to both intrastate and interstate pipelines; these entities in turn sold the gas to LDCs that delivered the gas to end users. With the issuance in 1992 of Order No. 636, the Commission required interstate pipelines to unbundle their services to separate the transportation of gas from the sale of gas. Thus, today most interstate pipelines do not engage in the buying and selling of natural gas except for operational purposes.

Order No. 636 further required interstate pipelines to set up informational postings to show available pipeline capacity and to ensure that all participants have access to available capacity. Additionally, holders of the firm capacity can, through capacity release, resell those rights on a temporary or permanent basis.

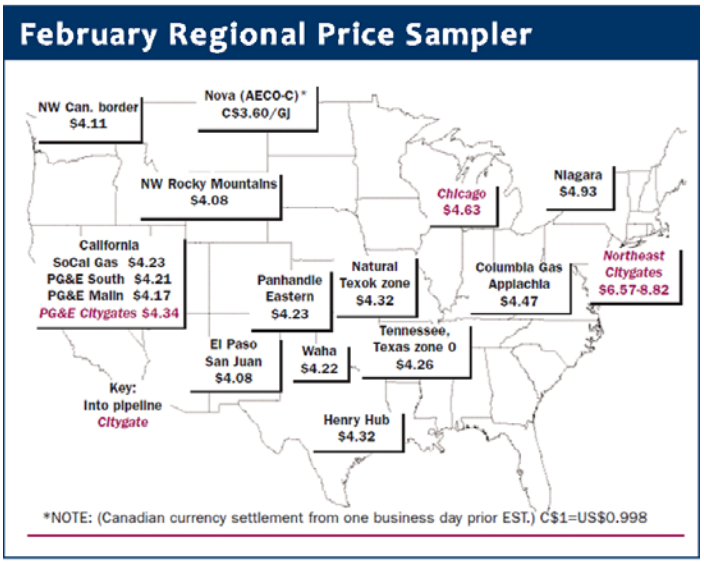
Natural Gas Marketing

Natural gas marketing mushroomed after the opening of access to pipeline capacity. Producers and marketers, in conjunction with the deregulation of wellhead gas, were granted blanket authorization to make sales at market rates. Marketers may now be affiliates of producers, pipeline companies, or local utilities, or be separate business entities unaffiliated with any other industry players. Marketers may also be associated with financial institutions. Marketing natural gas typically includes ensuring secure supplies and arranging for pipeline

[57] Pipeline Knowledge and Development, *The Interstate Natural Gas Transmission System: Scale, Physical Complexity and Business Model* (August 2010), *available at* www.ingaa.org/File.aspx?id=10751.

transportation, storage and accounting. Marketers also trade financial instruments to hedge commodity price risk and to speculate.[58]

For illustrative purposes, the following map depicts the February 2011 price for some regional gas trading hubs.[59] Waha and El Paso San Juan, shown on the map, are trading prices respectively applicable to the San Juan and Permian Basins. These two basins are important Southwest supply areas and figured prominently in the weather event of February 1-5.



Source: Platts Inside FERC's Gas Market Report February 2011

LDCs often make the final sale and transfer of gas to retail consumers. Unlike the interstate pipeline companies, many LDCs provide bundled sales and delivery services, although some may provide delivery services only. Many commercial and industrial customers contract for their own supply and purchase only transportation service from the LDC. There are more than 1,200 LDCs in the United States. LDCs can be stand-alone gas utilities, combination electric-gas utilities, or parts of integrated energy companies. The largest LDC is Southern California Gas Company (SoCalGas) with more than 20 million customers, followed by Pacific Gas and Electric Company and Atmos Energy Corporation.

[58] *Natural Gas Distribution*, NATURALGAS.ORG., http://www.naturalgas.org/naturalgas/marketing.asp (last visited Aug. 2, 2011).

[59] PLATTS INSIDE FERC'S GAS MARKET REPORT (Feb. 2011). Reprinted with permission of Platts.

Natural gas distribution companies typically deliver smaller volumes through smaller diameter pipes and at lower pressures than pipeline companies with systems that end at an individual household or place of business. Compressor stations are generally smaller than those found on the larger pipeline systems. Natural gas traveling through distribution pipelines will often be at a pressure as low as 3 psi to 0.25 psi at the customer's meter.[60]

Natural Gas Production in the Southwest

Texas and New Mexico are both prolific producers of natural gas, while Arizona has negligible production. In January 2011, Texas produced 31 percent of total United States production and New Mexico produced 6.2 percent.[61]

Texas and New Mexico contain a number of natural gas basins. The most significant of these with respect to the outages and curtailments experienced during the February cold weather event are the Permian, San Juan, and Fort Worth Basins.[62] Together, these three basins are responsible for almost 18 percent of total United States natural gas production.

The San Juan Basin straddles the Colorado and New Mexico border in the Four Corners region, and is a leading coal bed methane producing area. The basin is approximately 270 miles wide and covers over 4,000,000 acres.[63] Production is approximately 2.99 Bcf per day. The Permian Basin is located in West Texas and Southeastern New Mexico. It underlies an area approximately 250 miles wide and 300 miles long,[64] and produces on average 2.52 Bcf per day. The Fort Worth Basin contains the Barnett Shale Formation, with one of the largest producible

[60] *Natural Gas Distribution*, NATURALGAS.ORG, http://www.naturalgas.org/naturalgas/distribution.asp (last visited Aug. 2, 2011).

[61] In 2009, U.S. dry gas production was 20,580 billion cubic feet (Bcf) or 56.4 Bcf per day. Texas produced 17.5 Bcf per day on and off shore, and New Mexico produced 3.5 Bcf per day. EIA, *Natural Gas Withdrawals and Production*, http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_m.htm (last visited Aug. 15, 2011).

[62] Other onshore basins in the region include East Texas, the Gulf Coast and South Texas.

[63] La Plata Cnty. Energy Council, Gas Facts: San Juan Basin Map, http://www.energycouncil.org/gasfacts/sjbmap.htm (last visited Aug. 2, 2011).

[64] Charles D. Vertrees, *Handbook of Texas Online: The Permian Basin*, TEX. STATE HISTORICAL ASSN., http://www.tshaonline.org/handbook/online/articles/ryp02\ (last visited Aug. 2, 2011).

reserves of any natural gas field in the United States.[65] The basin produces 4.83 Bcf per day.[66]

Gas processing companies in the San Juan, Permian and Fort Worth Basins include DCP Midstream Partners, L.P., Enterprise Products Partners L.P., Williams Partners, L.P., Southern Union Gas Services, and Frontier Energy, L.L.C.

Natural Gas Pipelines in the Southwest

Intrastate gas pipelines in Texas comprise 45,000 miles out of the 58,600 total miles of gas pipeline in the state. This intrastate network delivers much of the region's natural gas, including deliveries to many large refining and petrochemical facilities, numerous electric generating facilities, and pipeline interconnects.[67] The largest intrastate pipelines in Texas are Enterprise Texas Pipeline LLC (8,750 miles) and the Energy Transfer Partners L.P. (8,800 miles). Other large systems include Atmos Pipeline – Texas (6,162 miles) and the Kinder Morgan Pipeline's Texas Intrastate Natural Gas Group (5,900 miles). Together these pipelines provide for transmission from west Texas supply and market hubs such as Waha, and for gas production in south Texas to the Houston Ship Channel, Katy Hub, the Dallas-Forth Worth area and other markets. Intrastate pipelines have expanded significantly due to increased demand for capacity to transport natural gas from the Barnett Shale Formation in the Fort Worth Basin south to the Katy area or out of the state. The following map shows the Texas intrastate pipeline grid.[68]

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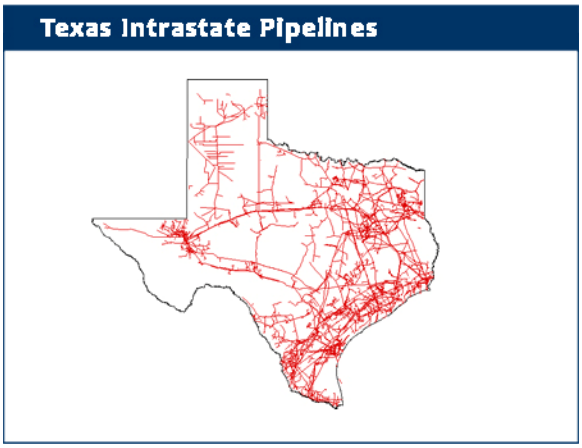
[65] The Perryman Group, *Bounty from Below: The Impact of Developing Natural Gas Resources Associated with the Barnett Shale on Business Activity in Fort Worth and the Surrounding 14-County Area*, at 5 (May 2007), *available at* http://www.barnettshaleexpo.com/docs/Barnett_Shale_Impact_Study.pdf. The Barnett Shale is one of the most significant onshore natural gas fields in North America, with thousands of wells producing hundreds of billions of cubic feet of natural gas each year. Production has risen sharply over the past several years as a result of improvements in recovery techniques.

[66] Staff's analysis based on supporting data, display reports and data warehouse on file with Bentek Energy LLC (unpublished); *See also Market Alert: Deep Freeze Disrupts U.S. Gas, Power, Processing*, Bentek Energy LLC, Feb. 8, 2011, at 2-6; additional materials were also obtained from natural gas pipelines.

[67] EIA, *Natural Gas Pipelines in the Southwest Region*, http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/southwest.html (last visited Aug. 2, 2011).

[68] EIA, *About U.S. Natural Gas Pipelines - Transporting Natural Gas:* Intrastate Natural Gas Pipeline Segment, http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/intrastate.html (last visited Aug. 2, 2011).

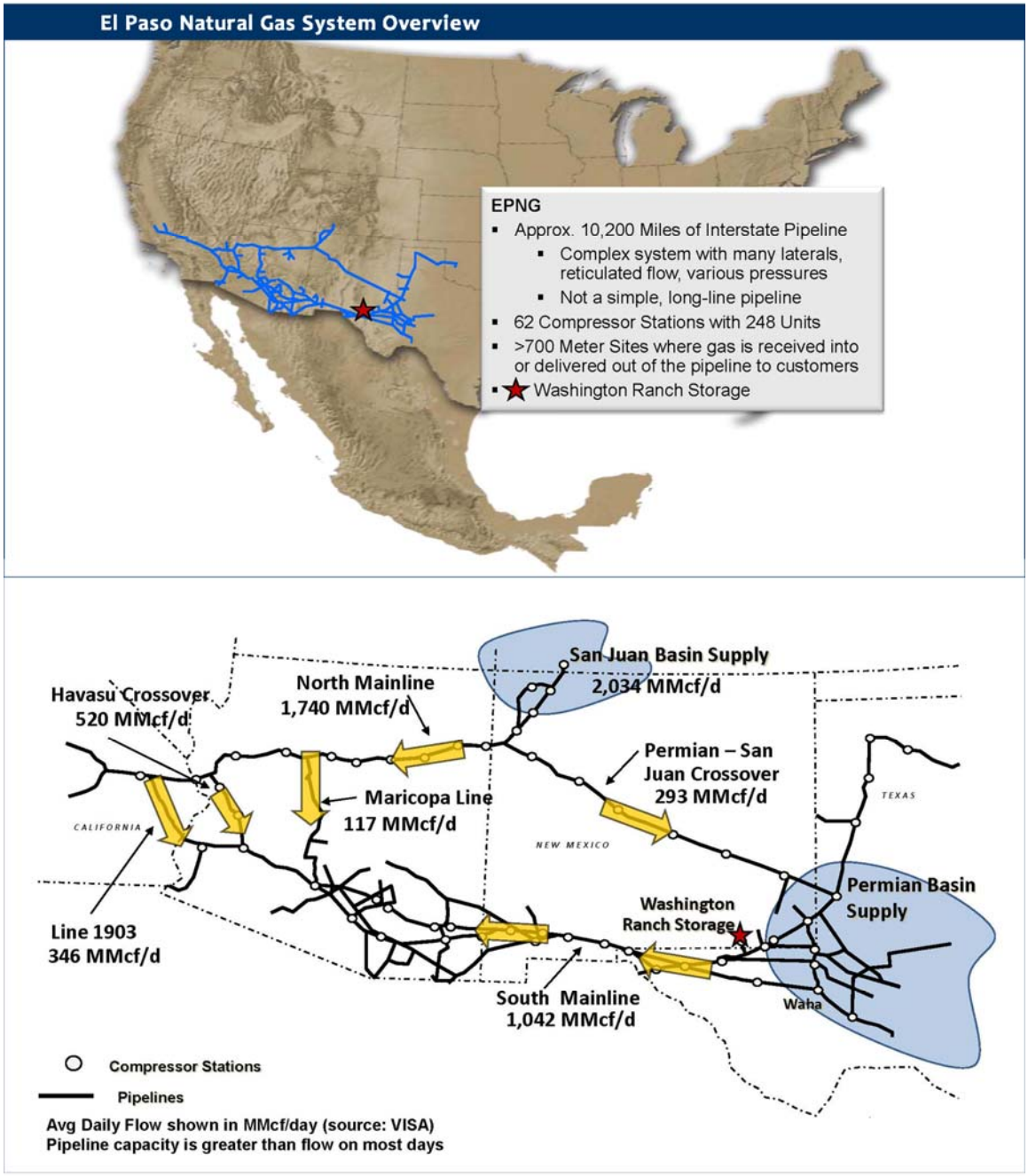


Source: Energy Information Administration

New Mexico and Arizona are supplied largely by two interstate transmission pipelines, Transwestern Pipeline Company, LLC (Transwestern) and El Paso Natural Gas Company (El Paso). These pipelines transport natural gas primarily from the San Juan and Permian Basins to the western regions of the United States. (The many other interstate pipelines that operate in Texas tend to transport gas to the Midwest and Northeast.)

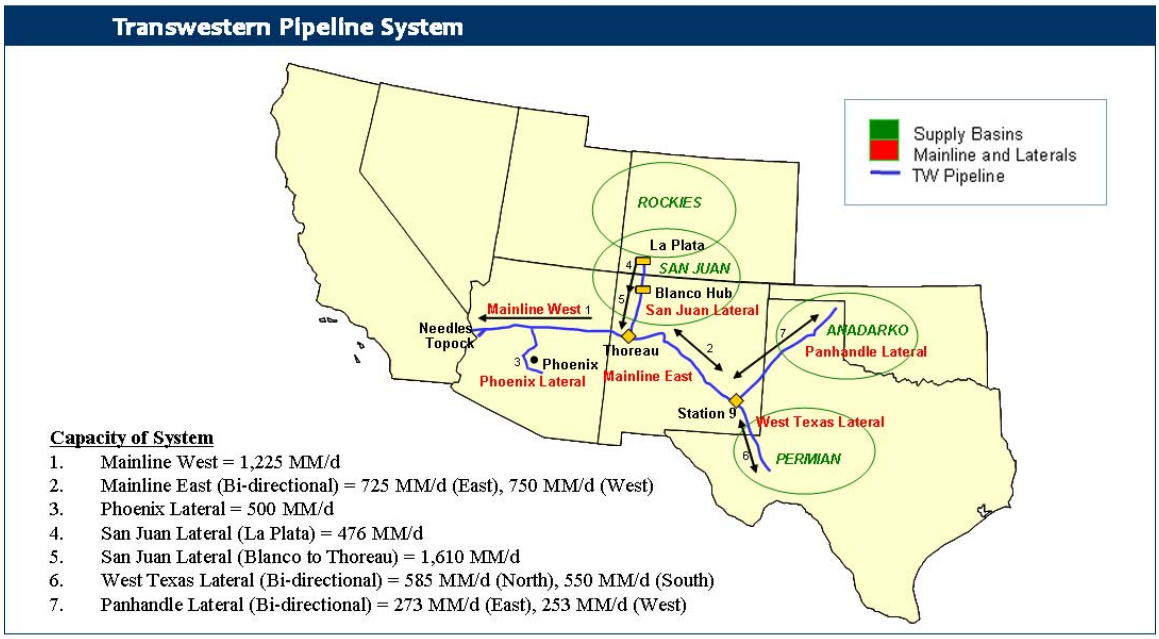
A brief description of these two interstate pipeline systems follows.

El Paso owns a transmission delivery system consisting of approximately 10,200 miles of pipeline. It is a complex, highly networked pipeline system with many laterals and interconnections, operating at a variety of flows and pressures. It includes 62 compressor stations and more than 700 meter sites where gas is delivered. It has 53 delivery meters to New Mexico Gas Company (NMGC), 216 meters to Southwest Gas Corporation (Southwest Gas), and 28 meters to Texas Gas Service. The system also includes the Washington Ranch Storage Field, one of the two storage facilities in the area between west Texas and the Arizona-California border.



Source: El Paso Natural Gas Company

Transwestern has approximately 2,700 miles of pipeline and 26 compressor stations. Its mainline capacity flowing west is 1,225 MMcf/day, and its San Juan Lateral capacity is 1,610 MMcf/day.[69]

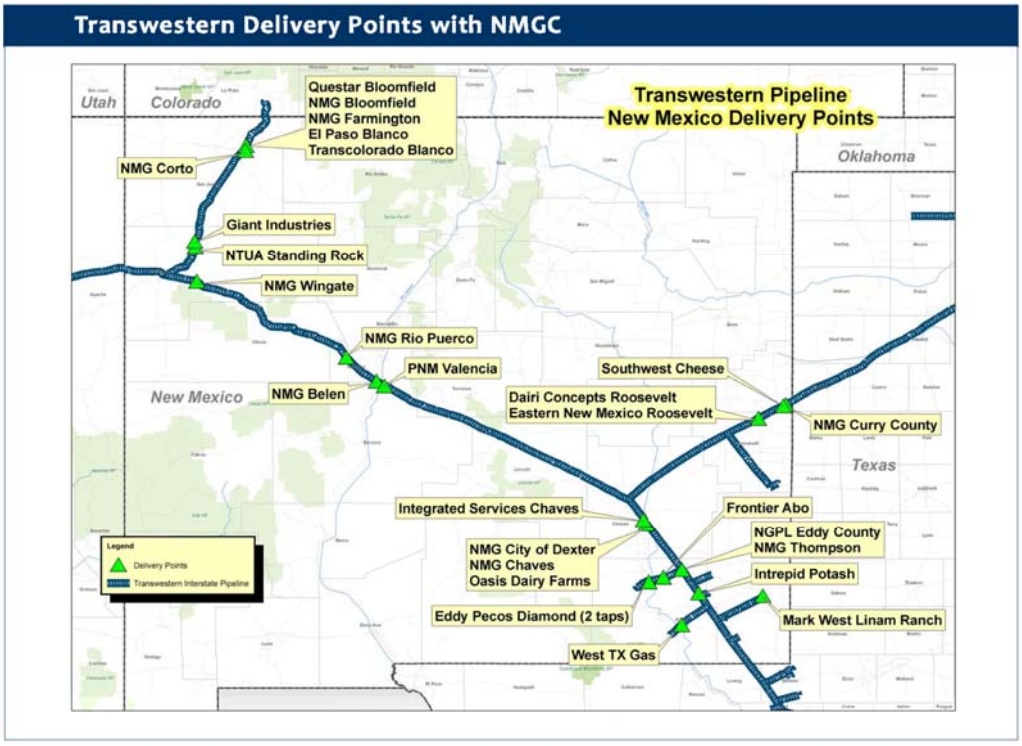


Source: Transwestern Pipeline Company, LLC

Transwestern has at least ten delivery points with NMGC.[70] In terms of flow volumes, the most significant of these during the February cold weather event was the NMG Rio Puerco, as shown in the following map.

[69] Throughout the report, MMcf refers to a million cubic feet, and Mcf to a thousand cubic feet.

[70] http://www.energytransfer.com/ops_interstate.aspx, and materials provided by Transwestern Pipeline Company, LLC to the task force.



Source: Transwestern Pipeline Company, LLC

These two pipeline companies, Transwestern and El Paso, are the interstate providers to those LDCs that experienced customer curtailments or outages in February 2011. Those LDCs are:

- New Mexico Gas Company, headquartered in Albuquerque. It provides gas service to more than 500,000 customers and maintains approximately 12,000 miles of natural gas pipelines.[71]
- Southwest Gas Corporation, providing gas service to more than 1.8 million residential, commercial and industrial customers in Arizona, Nevada and portions of California.[72]
- Texas Gas Service, the third largest natural gas distribution company in Texas. It provides gas to more than 603,000 customers in Austin, El Paso, and Rio Grande Valley areas as well as Galveston, Port

[71] New Mexico Gas Company, *About Us*, http://www.nmgco.com/about_us.aspx (last visited Aug. 2, 2011).

[72] Southwest Gas Corporation, *Profile of Southwest Gas*, http://www.swgas.com/about/aboutus/index.php (last visited Aug. 2, 2011).

Arthur, Weatherford and several communities in the Permian Basin and the Texas panhandle. [73]

- Zia Natural Gas Company, which provides gas service to over 35,000 customers in five New Mexico counties, serving primarily residential and small commercial users. In Lincoln County, where the city of Ruidoso experienced gas outages during the February event, Zia obtains gas from a direct interconnection to the El Paso Natural Gas pipeline.

Natural Gas Storage Facilities in the Southwest

There are two major natural gas storage facilities in the Southwest:

- **Washington Ranch Storage Field**, part of the El Paso system, is located in Eddy County, New Mexico, approximately nine miles southwest of Whites City. This facility has a working storage capacity of slightly more than 47.6 bcf and a maximum daily withdrawal capacity of 250,000 Mcf.

- **Chevron Keystone Storage Facility**, owned by Chevron Corporation, is located in Winkler County, in west Texas near Midland. This is a salt cavern facility with 6.38 Bcf of working gas. Its maximum daily injection capability is 200,000 Mcf and its maximum daily withdrawal capacity is 400,000 Mcf. It has interconnects to Transwestern, El Paso and the Northern Natural Gas Company's pipeline systems.

[73] Texas Gas Service, *Profile*, http://www.texasgasservice.com/en/About.aspx (last visited Aug. 2, 2011).

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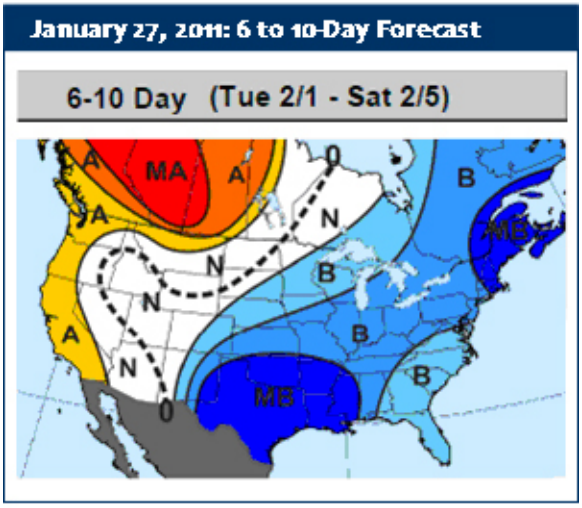
IV. Preparations for the Storm

A severe arctic cold front hit the central and northeastern United States and southern Canada on February 1, 2011, and lasted for several days. It was dubbed the "Groundhog's Day Blizzard of 2011."[74] The front was not unexpected. About a week prior to the event, long-range forecasts predicted an outbreak of very cold temperatures for the first week of February, with wind, ice, and snow from Texas to Mississippi. Arctic air was expected to extend southward to the Gulf Coast by February 2, bringing daytime highs to as low as 30 degrees below normal. Sustained winds of 20-25 mph, with higher gusts, were also anticipated.[75]



[Color legend: N is normal, B is below normal, MB is much below normal, and SB is strong below normal.][76]

[74] National Oceanic and Atmospheric Administration National Climatic Data Center (NCDC), *State of the Climate: Global Hazards for February 2011*(March 2011), http://www.ncdc.noaa.gov/sotc/hazards/2011/2#winter.

[75] Weather data used in this section is drawn from NCDC data. Raw land-based observation data was obtained at http://www.ncdc.noaa.gov/oa/land.html. Quality controlled local climatological data was obtained at http://cdo.ncdc.noaa.gov/qclcd/QCLCD?prior=N. Additional data, unless otherwise noted, is drawn from materials provided to the task force by BAs, transmission operators, generators, producers, processing plants, pipelines and LDCs.

[76] EarthSat is a private forecasting service used by many entities in the energy industry and by the Commission in connection with its market monitoring efforts.

A. Weather Conditions During the Event

Actual weather conditions between February 1 and 5, 2011 turned out to be largely as predicted by the National Weather Service's long-range forecasts. However, actual temperatures were a few degrees lower than forecasted, especially in west Texas and New Mexico. In some places, temperatures did not rise above freezing until February 4. Low temperatures in Albuquerque ranged from -7 degrees to 7 degrees over the four-day period, in Midland from 6 degrees to 12 degrees, and in Dallas from 13 degrees to 19 degrees.[77]

As the storm hit during the early morning hours of Tuesday, February 1, temperatures in the western-most cities of the Southwest plummeted dramatically. Daily highs at Albuquerque and Dallas fell 20 degrees (to 28 degrees and 39 degrees respectively) from the previous day, while at Midland the recorded high was 30 degrees, which was 43 degrees below that of the previous day. Houston's temperatures started out on February 1 at 70 degrees, but by 7:00 AM had dropped to 45 degrees.

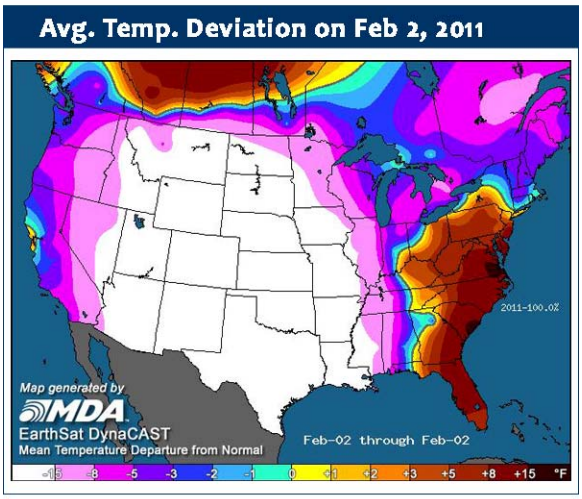
The wind profile was also changing dramatically. Wind speeds had rarely exceeded 10 mph the preceding day, but by the morning of February 1 Albuquerque was experiencing sustained wind speeds of 20 mph (representing a wind chill index of 4 degrees), with gusts to 27 mph. Winds in Midland hovered around 20 mph and gusted to over 30 mph. Light snow began falling in both cities around midnight. It was also windy in Dallas on February 1, with speeds of up to 25 mph and gusts between 20 and 40 mph.

Conditions worsened at all locations through the day, and by midnight temperatures were extremely low. Albuquerque was at 4 degrees, with continuing high winds and snow. Temperatures at Midland were 14 degrees and at Dallas 16 degrees. The cold air finally hit Houston late in the day, with temperatures of 27 degrees and winds of 14 mph, although without precipitation.

By Wednesday, February 2, early morning conditions had become severe. In Albuquerque, the temperature at 8:00 AM was 1 degree, almost 40 degrees below the average for that date, and the wind was blowing at 26 mph. Temperatures in El Paso and Midland hovered around 10 degrees for much of the day, with wind speeds of 15 mph. El Paso set a record low for the day of 6 degrees at 5:00 AM, and recorded the third coldest day in 38 years. In fact, February 2 turned out to be one of the coldest days on record in the last 25 years across the state of Texas, with average temperatures well below freezing and only

[77] All temperatures in this report are in degrees Fahrenheit.

Brownsville escaping severe conditions (with average temperatures of about 35 degrees). Significant winds accompanied the frigid temperatures, with wind chill factors dropping the perceived temperatures to -6 degrees in Dallas and 6 degrees in Austin.



Source: MDA EarthSat

On Thursday, February 3, weather conditions began to marginally improve in some areas, although in Albuquerque and El Paso it would rank as the coldest day in 38 years. Albuquerque, Midland and El Paso were still experiencing highs near 15 to 20 degrees, but the winds had begun to diminish. From Dallas to San Antonio, temperatures moderated about 5 to 10 degrees, but wind speeds remained high.

On Friday, February 4, conditions improved across the region. Temperatures in the western cities finally rose above freezing, and in a few of the eastern-most cities rose above 40 degrees. Nonetheless, during the early morning hours, El Paso hit a low of 3 degrees before reaching a high of 37 degrees, ranking the day as the city's second coldest in 38 years. Four to six inches of snow fell in the Dallas Metropolitan area, causing cancellation of more than 300 flights at Dallas airports just as fans were arriving for the Super Bowl.

Cold weather hit the region again on February 9 and February 10. The coldest temperatures were seen on February 9, when El Paso recorded a low of -2 degrees, and Midland a low of 7 degrees. Daily highs, however, were in the 30s and 40s. Other cities saw lows dip into the 20s and teens, with high temperatures rising into the 40s and 50s.

There is no question that the cold and windy weather during this first week of February was both sustained and severe. Just how severe, when compared to

prior storms, is examined in the section of this report entitled "Prior Cold Weather Events."

B. Preparations for the Storm: Electric

Three balancing authorities in the Southwest shed load during the cold weather event: ERCOT, SRP and EPE. (PNM lost some 26 MW of load as well, although this was the result of localized transmission issues largely unrelated to the storm). Customers in ERCOT were affected the most, by a large margin. ERCOT shed 4000 MW of load, affecting 3.2 million customers, on February 2. It shed another 300 MW on February 3, affecting 180,000 customers. In comparison, SRP shed 300 MW of load, affecting 65,000 customers, and EPE shed a little over 1000 MW of load, affecting 253,000 customers.[78]

The preparations for the storm taken by these three entities are discussed below.

ERCOT

Going into the winter season of 2010/2011, ERCOT had substantial reason to believe it could meet its projected demand with available generation and imports. ERCOT's peak demand for the winter of 2010/2011 was forecasted to be 47,824 MW, with the peak anticipated to occur in January.[79] (This forecasted peak was 11 percent higher than the forecasted peak for the previous winter.[80]) To meet that peak demand, ERCOT had projected generation capacity plus imports of 72,881 MW.[81] Thus, for planning purposes, ERCOT could anticipate a

[78] In the case of ERCOT, these numbers represent the amount of load the transmission providers were directed to shed. Actual load shed was somewhat higher (5411.6 MW on February 2 and 459.5 MW on February 3), for reasons discussed in the section of this report entitled "The Event: Load Shed and Curtailments."

[79] NERC, *2010/2011 Winter Reliability Assessment*, at 16 (Nov. 2010), *available at* http://www.nerc.com/files/2010_Winter_Assessment_Final_Posted.pdf. NERC prepares its reliability assessments based on data and information submitted by the applicable Regional Entity, which in ERCOT's case is TRE.

[80] ERCOT modified the forecasting models because it had experienced extreme cold weather in January of 2010, with load tracking notably higher than forecasted.

[81] Resources listed in the NERC 2010-2011 Winter Reliability Assessment consisted of available generation (72,500 MW) and net firm imports (381 MW), and did not include generating units which were known well in advance to have scheduled maintenance outages spanning the expected peak load period. Demand was calculated based on a 50/50 load forecast (47,824 MW), meaning the forecast is expected to be exceeded five years out of every ten.

comfortable reserve margin of 57 percent. This percentage compares favorably with NERC's reference reserve margin for ERCOT of 13 percent, considered by NERC to be the base level required for reliability.[82]

The estimated demand for the season included only firm load, and therefore did not include ERCOT's two categories of contractually curtailable load: Load Resources (formerly designated as Load Acting as a Resource, or LaaR), which may be automatically disconnected when system frequency drops below a prescribed threshold (totaling 1062 MW as of February 2); and Emergency Interruptible Load Service (EILS), which permits curtailment prior to firm load shedding (totaling 331 MW as of February 2).

Although ERCOT seemingly had a generous reserve margin going into the winter of 2010/2011, the reserve margin cited did not take into account planned outages that were not yet known at the time of the forecast. ERCOT is a summer-peaking system, and the high summer temperatures and demand often extend into what would be considered shoulder seasons in more northerly regions. For that reason, it is not unusual for generators in ERCOT to schedule maintenance outages in February. ERCOT does not have the authority to prohibit generators from scheduling such outages or from taking them as scheduled, unless the outage is scheduled eight days or less before the outage date, or the outage would keep ERCOT from meeting applicable Reliability Standards or its own Protocol requirements.[83] At most, pursuant to its Protocols, ERCOT can ask generators to refrain from taking a scheduled outage if it believes it may need the generator's output. ERCOT also does not have authority under its Protocols to require generators that are on planned outage to come back into service early (assuming the generator is even in a condition to do so). Nor are there any market mechanisms to compensate generators for any costs associated with delaying or coming back early from a scheduled outage.

Despite these potential limitations, ERCOT was far from being generation deficient for winter 2010/2011 seasonal planning purposes. Nor, as will be seen, did it appear to be deficient going into the storm itself. A little background is needed to put in context the generation that ERCOT thought it would be able to call upon during the storm.

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[82] NERC 2010/2011 Winter Reliability Assessment at 16.

[83] ERCOT Nodal Protocols § 3.1 (Nov. 20, 2010), *available at* http://www.ercot.org/mktrules/nprotocols/2010/index. ERCOT is considering revising this provision to permit it to deny an outage request if it is scheduled 90 days or less from the outage date.

ERCOT uses proprietary forecasts (performed both on a seasonal and daily basis) to predict its load.[84] ERCOT used those weather forecasts, coupled with historical and other information, to gauge expected customer demand during the approaching event. A task force review of ERCOT's forecasts determined that they accurately predicted the February storm conditions, and in some cases their weather estimates were even slightly more accurate than those of the National Weather Service.

ERCOT then compared the anticipated demand[85] against its generation capacity, both for purposes of scheduling power in the day-ahead market and for determining whether it would meet reliability and reserve requirements. For operating purposes, ERCOT's Protocols include a responsive reserve requirement (also referred to as Physical Response Capability, or PRC) of 2300 MW. The primary purpose of the responsive reserves is to restore system frequency to 60 Hz within the first few minutes after the system experiences a significant frequency deviation. The 2300 MW amount is based on a 1988 study that determined the reserves that would be needed to prevent the shedding of firm load upon the simultaneous loss of the two largest generation resources in the ERCOT region.[86] (Actual online responsive reserves at any given time typically exceed the 2300 MW requirement.[87])

ERCOT Protocols

The ERCOT protocols set forth the procedures and processes used by ERCOT and its market participants for the orderly functioning of the ERCOT system and market. They contain

(cont'd)

[84] ERCOT relies on Telvent DTN and Pattern Recognition Technologies (PRT) for the weather data used in its load forecasts.

[85] ERCOT's load forecast projected loads of 52,673 for February 1 and 57,436 for February 2.

[86] This is a more conservative measurement than that required by NERC Reliability Standard BAL-002-0 R3, which sets a "contingency reserve" requirement to cover the loss of the single largest contingency on a Balancing Authority's or Reserve Sharing Group's system (N-1), not the loss of the two largest contingencies. Because ERCOT is not synchronously linked with other interconnections, a larger reserve amount than N-1 is required to maintain proper frequency response.

[87] ERCOT's daily morning report listed responsive reserves of 4196 MW for February 1 and 5944 MW for February 2, projected for the peak hours of those days.

policies for scheduling, operations, planning, reliability, and settlements, as well as ERCOT's rules, guidelines, procedures, and standards. The protocols are developed and amended through stakeholder committees for approval by the ERCOT Board of Directors. Once approved at ERCOT, the protocols are submitted to the PUCT for final approval. In addition to its task of enforcing the FERC-approved Reliability Standards, TRE is responsible for compliance monitoring and enforcement of the ERCOT Protocols.

In addition to the responsive reserve requirement, ERCOT must meet a non-spinning reserve requirement.[88] These reserves are intended to address the risks of load uncertainty and wind power output variability. For February 2011, the non-spinning reserve requirement was set at 2000 MW. (The sources counted for non-spinning reserves are not included in the calculation of available resources for purposes of meeting the responsive reserve requirement of 2300 MW.[89])

Notwithstanding the fact that 11,566 MW of generation were on scheduled outage as of February 1,[90] ERCOT had more than 3100 MW of responsive

[88] Non-spinning reserves in ERCOT are generation resources capable of being ramped to a specified output level within thirty minutes and running at that level for at least one hour, or Load Resources that are capable of being interrupted within thirty minutes after being asked for interruption and remaining de-energized for at least one hour.

[89] Wind resources, which are forecasted on an hourly basis, are also not included in the calculation of available resources for purposes of meeting the responsive reserve requirement. One of the most significant differences between the NERC Winter Assessment and ERCOT operations is how wind power is handled. The NERC Winter Assessment assigns a fixed average output of 8.7 percent of nameplate rating as "existing-certain" generation capacity. For the 9317 MW of installed wind capacity (aggregate nameplate rating) in ERCOT, this amounts to 811 MW. Operations, on the other hand, utilizes wind power forecasts derived from highly localized wind speed forecasts, which provide wind power output values for each of the upcoming 48 hours. The forecasts are re-run hourly and the results updated accordingly, yielding a "rolling" 48 hour look-ahead. ERCOT's Current Operating Plan (COP) for wind power uses a conservative estimate which has an 80 percent chance of being met or exceeded, and already takes into account any equipment outages, either scheduled or forced. On the morning of February 2, the aggregate COP for wind power peaked at about 5200 MW at 3:00 AM and decreased steadily each hour down to 3500 MW at 8:00 AM. The actual wind power output followed the same downward trend, but fell short off the COP numbers anywhere from 400 MW to 1000 MW, depending on the specific hour. (This snapshot picture exhibits the variability of wind power.)

[90] This number grew to 12,413 MW on February 2; however, the additional units might have been ones that experienced forced outages on February 1 and then transitioned into scheduled outages.

reserves available throughout the entire 24 hours of that day, running as high as 5600 MW in the early morning and again during the mid-afternoon hours. This exceeded the responsive reserve requirement of 2300 MW by a comfortable amount.[91]

Thus, on paper, ERCOT had reason to believe it had ample generation going into the storm.[92] As it turned out, the large number of generator outages, derates and failures to start that occurred on February 1 and February 2 would reduce that margin below acceptable levels.

Aside from determining it had sufficient operating reserves listed as available, ERCOT took other steps to prepare for the storm. On January 31, ERCOT issued an Operating Condition Notice (OCN) to its market participants, advising them of the expected cold front. On February 1, it issued another OCN at 2:45 AM and an Advisory at 9:05 AM. ERCOT also reported to the PUCT that it was expecting temperatures in the teens to the low 20s and maximum temperatures near or below freezing, with anticipated impacts on 50 percent or more of its major metropolitan areas.[93]

Notices and Emergency Declarations

The ERCOT Protocols set out three types of preliminary notices to be issued by ERCOT to inform market participants of a potentially adverse operating condition, including extreme weather conditions such as hurricanes and protracted periods of below-freezing temperatures. The type of notice is determined based on the time available for the market to respond before an emergency condition may occur.

(cont'd)

[91] On February 2, responsive reserves would hover in the range of 2700 MW to 3300 MW in the early morning hours, dropping to around 3000 MW at 4:30 AM and then plummeting rapidly.

[92] In addition to the outages already underway, three planned generation outages were scheduled to begin during the time period covered by the anticipated storm. ERCOT requested one of these generators to delay the outage, as discussed later in the report.

[93] ERCOT did not provide any further market notices or indications of projected capacity shortages until 3:00 AM on February 2, when it issued an OCN and an Advisory reporting that reserves were below 3000 MW. These notices, as well as the other actions that took place on February 2, are discussed in the following section of this report entitled "The Event: Load Shed and Curtailments."

- Operating Condition Notice -- issued to inform participants of a possible future need for more resources due to conditions that could affect system reliability; allows ERCOT to confer with transmission providers and participants regarding the potential for adverse reliability impacts and contingency preparedness when adverse weather conditions are expected.

- Advisory -- issued when conditions are developing or have changed such that more ancillary services will be needed, or when weather or conditions require more lead-time than the normal day-ahead market allows; allows ERCOT to increase ancillary services requirements above the quantities originally specified in the day-ahead market, and to require information from participants regarding their fuel capabilities for the next seven day period.

- Watch -- issued when additional ancillary services are needed in the current operating period, or when forced outages or abnormal operating conditions have occurred or may occur that require operating with transmission security violations; allows ERCOT to instruct transmission owners to reconfigure ERCOT system elements to improve reliability in ERCOT; and allows ERCOT to take steps to procure additional regulation services, RRS services, and non-spinning services.

ERCOT issues the fourth level of Notice, an Emergency Notice, when it cannot maintain minimum Reliability Standards or meet its Protocol requirements during the operating period or is otherwise in an unreliable condition. Depending on the severity level, ERCOT may take additional steps to resolve the system emergency, including relaxing transmission constraints, issuing public appeals for conservation, deploying Load Resources and EILS resources, and requiring firm load shedding.

Between January 28 and January 31, ERCOT cancelled, withdrew, or delayed planned outages on ten 345 kV transmission lines, 27 138 kV transmission lines, two 345/138 kV auto-transformers and one 138/69 kV transformer (outage cancellation rules differ as between transmission and generation). On January 31, ERCOT requested one generating unit (Mountain Creek SES Unit 8 at 568 MW) to begin start-up due to its long start-up lead time, and requested another unit (Lake Hubbard SES Unit at 397 MW) to convert from natural gas to fuel oil in anticipation of possible gas curtailments.[94] ERCOT reports that it did not request any generators to return early from scheduled

[94] Texas Reliability Entity, *Event Analysis Report – Feb.2, 2011 EEA-3 Event* at 16 (Apr. 15, 2011) (TRE Report).

outages, nor did it request any generators to defer scheduled outages that were slated to start during the cold weather event.[95]

In the afternoon of January 31, ERCOT decided to adjust its load forecast to factor in the potential effect of the high winds that had been predicted (ERCOT's forecasts do not normally factor in wind chill effects). ERCOT made a manual adjustment to its load forecast for the remainder of February 1 and for February 2, adding 4000 MW.

The storm hit on February 1. Beginning at approximately 12:00 PM on that day, power plants across Texas experienced problems due to the cold weather. These included freezing instrumentation, freezing pipes, freezing drain lines, natural gas curtailments, and natural gas pressure reductions due to high usage.[96] Between noon and midnight on February 1, two large coal units and 18 natural gas units tripped or failed to start for varying periods of time. Another six natural gas units and 13 wind plants were derated during this period. As of midnight on February 1, unavailable generation capacity in ERCOT (not counting scheduled outages) reached 6022 MW.[97]

In addition to the generation scheduled for February 2 by its economic dispatch model, ERCOT committed 24 additional generating units, totaling 3400 MW, through its reliability unit commitment (RUC) process.[98] By midnight, all available generation had been instructed to run on February 2.

[95] ERCOT did discuss with generators deferring scheduled outages planned for the February 10 period, when cold weather was again anticipated. Some of those scheduled outages were postponed.

[96] TRE Report at 7. The details of the types and causes of the forced outages experienced during the February 1-5 weather event are discussed in detail in the section of this report entitled "Causes of the Outages and Supply Disruptions."

[97] This is a net cumulative number; that is, if a failed unit came back online, it is not counted as unavailable.

[98] ERCOT initially committed 13 units through the RUC process on February 1, to be deployed on February 2; it later cancelled six of those unit commitments, leaving a net value of 2049 MW in additional generation as of midnight on February 1. At 3:03 AM on February 2, ERCOT committed 19 units through its RUC process, totaling 1351 MW. Unit generation added on both days through the RUC process for February 2 deployment totaled 3400 MW.

ERCOT's RUC Process

After ERCOT completes the run of its day-ahead market, which matches buy and sell offers for energy and ancillary services for the following operating day, ERCOT runs a Day-Ahead Reliability Unit Commitment (DRUC) study to ensure that sufficient capacity is available to serve load. For each hour of the following day, the DRUC examines whether sufficient resources have been committed, through Day-Ahead awards or as otherwise reflected in each resource's Current Operating Plan (COP), to meet the forecasted load for each hour. If ERCOT determines that any additional resources are needed, it can physically commit those resources for the hours needed, with certain payment levels guaranteed to the resources when ordered to run.

ERCOT runs the DRUC study in the afternoon prior to the operating day studied. Hourly RUC (HRUC) studies are run thereafter, comparing resources and load for each hour remaining in the DRUC period and reflecting any changes in resource commitments (such as forced outages or modified COPs) or other changes in system conditions since the DRUC was run.

The RUC process takes into account resources committed in the Day-Ahead market, resources self-committed in the COPs, and resources committed to provide ancillary services. The RUC process can also recommend decommitment of resources where transmission constraints are not otherwise resolvable. ERCOT can order any available resource to come online as part of the RUC process.

If a resource is selected by the RUC, the resource will at a minimum be made whole for its startup and minimum-energy costs. However, if the energy revenues received during the RUC-commitment period are greater than these guaranteed costs, the resource may be subject to a "clawback" under certain conditions.

Could or should ERCOT have done more to prepare for the event? ERCOT procedures specifically include provisions for severe cold weather operations.[99] In anticipation of severe cold weather, ERCOT may issue an OCN, Advisory, Watch, or Emergency Notice. These various alerts allow ERCOT to react to potential operating conditions by: reviewing planned and existing outages; determining if more lead-time is needed for generating resources to meet their commitments than the normal day-ahead market allows; determining if additional ancillary services are required; ordering on additional units; and increasing staffing. Under the

[99] ERCOT Operating Procedure Manual: Shift Supervisor Desk § 7.5 (July 18, 2011), *available at* http://www.ercot.org/mktrules/guides/procedures/. Severe cold weather is defined by expected temperatures in the mid to low 20 degree range with expected maximum temperatures near or below freezing, impacting 50 percent or more of major metropolitan areas.

various alerts, ERCOT's RUC Operator may also confer with transmission operators and QSEs[100] regarding preparedness, fuel capabilities, the need to reconfigure system elements, or to vary from market timing deadlines.[101]

In anticipation of the event, ERCOT arguably could have better utilized these tools to prepare for the severe cold weather, particularly by increasing ERCOT's responsive reserves well in advance of its decision late on February 1 to schedule all available units for the next day.[102] As events proved, the extensive generator outages substantially exceeded ERCOT's reserves, and would have done so even if the reserves had been substantially larger in number. But this was not known by ERCOT going into the event. Furthermore, if generating units had been online and running, they would have been better able to withstand freezing temperatures,[103] a consideration ERCOT might have factored into its decision-making process.

Another strategy that might have improved generator response would have been the use of pre-warming techniques.[104] ERCOT does not currently have the authority to require generators to engage in these actions, but if generators had done so, they might have prevented some of the extensive freezing problems that developed. Running quick start units prior to their scheduled start time could also

[100] A "Qualified Scheduling Entity" (QSE) is a market participant qualified by ERCOT as a resource entity or a load serving entity, for purposes of communications with ERCOT and the settling of payments and charges.

[101] ERCOT Operating Procedure Manual, Reliability Unit Commitment Desk, Section 6.1 (July 20, 2011), *available at* http://www.ercot.com/mktrules/guides/procedures/.

[102] ERCOT Protocols formerly required it to increase its spinning reserves by an amount at least equal to its responsive reserves during cold weather alerts. *See* Elec. Reliability Council of Tx., *ERCOT Operating Guide No. 12* (May 1989). ERCOT advised the task force that this protocol had been changed to account for the variability of wind power. ERCOT now carries non-spinning reserves continuously rather than only during peak hours, as was its former practice. ERCOT stated its belief that the continuous availability of non-spinning reserves serves virtually the same purpose as the former practice of doubling the spinning reserves.

[103] The use of a generating unit's own radiant heat to prevent freezing is discussed in the section of the report entitled "Key Findings and Recommendations."

[104] For conventional gas steam units, pre-warming can be accomplished by establishing a fire in the boiler to produce warming steam for the turbine while it is on turning gear. This keeps metal temperatures warm enough to prevent freezing in piping and instrumentation lines and helps bring lubricating and hydraulic oils up to proper operational temperatures. Combustion turbines can run at full speed no-load operation for short periods of time prior to start up, in order to warm vital parts, instrumentation, and lubricating oils.

have identified problems before the output of the units was needed, giving them time to make corrections.[105]

Had ERCOT and the generators undertaken these additional measures, it is possible that fewer generating units might have failed. ERCOT might still have been forced to shed load, but the extent of the load shed might well have been reduced. Every generator that could have escaped failure on February 1 and February 2 would have improved the situation for Texas consumers.

ERCOT Generators

Most generators in ERCOT's footprint reported having employed freeze protection measures to protect their facilities. These measures generally fell into two categories: physical readiness and operational readiness.

To prepare physical facilities for the cold weather, generators variously reported that they installed portable heaters to maintain ambient air temperature, added extra insulation to exposed components, installed temporary windbreaks to exposed areas, drained non-essential water systems, and determined that the water in essential water systems was circulating.

Some generators also reported adjusting their operations to adapt to the cold weather. They called in more operating and maintenance staff, increased the frequency of operator rounds, performed checks of freeze protection panels and heat tracing circuits, and added windbreaks. Plant staff also tested emergency equipment, added fuel to heaters and emergency generators, stocked extra supplies of fuels as well as food and other emergency items in case deliveries were disrupted, and prepared sleeping arrangements for employees if roads became impassable. Some generators utilized pre-operational warming during the event.[106]

Despite these reports of having taken steps to prepare for the cold weather event, many generating units in ERCOT failed to perform or suffered derates after

[105] On February 1 and 2, approximately 19 simple cycle and combined cycle units in ERCOT tripped for non-weather related causes and were restored within two hours. Many of the simple cycle and combined cycle unit trips occurred immediately during start-up sequences or very soon after synchronization.

[106] On February 10 as well, some generators utilized pre-operational warming for that day's cold weather snap. At least five generators kept their units running, started units earlier or took other measures to keep from having a "cold start." These generators credited these strategies for their improved performance on that date.

the storm hit. And they failed, in the majority of cases, because of weather-related problems. The various generator outages and their causes are examined in the section of this report entitled "Causes of the Outages and Supply Disruptions."

Salt River Project

SRP is a vertically integrated utility and owns its own generation, transmission, and distribution facilities. Its preparations for inclement weather therefore needed to encompass all three functions. In terms of its forecasting, SRP uses an Artificial Neural Network Short-Term Load Forecaster model, which projects control area loads. This model incorporates SRP's own meteorologist's weather forecast as well as hourly historical load data. SRP reported that while weather on February 2 matched its weather forecasts, its load forecast was lower than actual load demands. The disparity, however, was within five percent.

SRP has generating facilities located throughout central and northern Arizona. Winter temperatures tend to be mild in and around the Phoenix Valley but can be noticeably colder in the more remote areas where the company's two coal burning facilities are located. SRP reports that it carries out preventative maintenance for facilities that have winterization equipment, which generally consists of heat tracing[107] and insulation. Gas-fired generating plants in and around the Phoenix valley use winterization equipment to protect against expected conditions, while hydro generating facilities are almost exclusively contained inside protected buildings. SRP's coal generating facilities at the Coronado and Navajo stations have winterization systems that consist mostly of heat tracing and insulation. SRP advised the task force that every year in the fall, planners for the Coronado and Navajo stations develop work orders to inspect and test these winterization systems to verify they are working properly, and that during the winter months, staff conduct weekly winterization and freeze protection equipment checks.

SRP's immediate preparations for the February event were limited. It did not issue a cold weather alert in advance of the storm.[108] SRP reports that management at the Navajo Generating Station did inform its operators at the beginning of shifts that cold weather was approaching, and inquired if there was anything the employees needed to help them do their job. SRP does not employ a

[107] Heat tracing refers to the application of a heat source to pipes, lines, and other equipment.

[108] Indeed, the only alert the SRP Balancing Authority provided to generators was a "Capacity Alert," indicating that maintenance and operations activities on all operating generating units were to be stopped.

formal checklist of activities that should be carried out prior to a winter storm, and the company reported that the Operations and Maintenance Group at the Navajo Generating Station did not take any formal actions to prepare the station for the anticipated severe weather. However, SRP informed the task force that the group did hold meetings at which the need for staff to frequently check the generating equipment for potential weather-related problems was emphasized.

El Paso Electric

Like SRP, EPE is a vertically integrated utility. It reported to the task force that at the beginning of the winter of 2010/2011, as at the beginning of every winter, it took steps to winterize its generating facilities. This winterization included verifying that heat tracing was properly functioning, as well as making sure insulation was properly installed.

EPE also reported that it verified that the equipment in its substations, the part of the transmission and distribution system most susceptible to cold temperature extremes, could withstand the expected cold temperatures.

On January 31, 2011, EPE initiated preparations for the anticipated severe weather, which included verifying winterization of generation, transmission and distribution facilities, reviewing system operations plans, checking on the availability of fuel, preparing for potential pipeline constraints, and placing employees on call as needed during the weather event. The Systems Operations group requested EPE's Power Marketing and Fuels group to keep additional generation online. In response, the Power Marketing and Fuels group made arrangements to leave on Rio Grande Unit 6, to continue with the start-up of Newman Units GT-3 and GT-4, and verified the ability of Newman Unit 3 to operate on fuel oil.

In contrast to some other areas in the region, EPE reported that actual weather during the event was more severe than forecasted (and significantly colder than historical temperatures). For February 2, EPE reported that the actual high temperature in El Paso was 15 degrees compared to a forecasted high of 37 degrees, and the actual low temperature was 6 degrees compared to a forecasted low of 14 degrees. The forecasted high for February 3 was 30 degrees, compared to an actual high of 18 degrees, and the forecasted low was 14 degrees, compared to an actual low of 1 degree. For February 4, the last day of the freeze event in EPE's service territory, the forecasted high of 43 degrees compared to an actual high of 37 degrees, and a forecasted low of 21 degrees compared to an actual low of 3 degrees. EPE did not report the exact location for its temperature statistics, but presumably they occurred in the west Texas and New Mexico regions.

C. Preparations for the Storm: Natural Gas

Varying levels of preparation for the February cold front were employed by the producers, processing plants, interstate pipelines, intrastate pipelines, and LDCs that together make up the natural gas delivery chain. Depending on the type of facility, preparations included at least one, if not several of the following items: monitoring the weather, increasing staffing, methanol injection, pigging, insulation, tarps, heat tracing, building line pack[109] in pipelines by injecting more gas, over-purchasing gas supplies and enhancing winterization equipment. For the most part, facilities began their preparations by either Sunday, January 30 or Monday, January 31.

This section describes the preparations taken by individual companies in west Texas, the Texas panhandle, north Texas and New Mexico and by the LDCs in Arizona and New Mexico.

Producers

As discussed in detail in the section of this report entitled "Causes of the Outages and Supply Disruptions," the difficulties encountered by LDCs in trying to meet customer demand stemmed principally from supply declines in the basins, and secondarily from problems encountered at processing plants. The preparations for the cold weather event taken by producers is therefore of special interest.

Of the 15 producers who provided information to the task force on this issue, all reported that they had used winterization techniques of one sort or another. The following table shows by basin the numbers of producers that used one of or more of the listed methods.

[109] Line pack refers to the volume of gas in the system at any given point in time.

	PERMIAN	SAN JUAN	FORT WORTH	EAST TEXAS	TEXAS GULF
Methanol Injection or Drip	✓✓✓✓✓✓✓	✓✓✓	✓✓✓✓✓	✓✓✓✓✓✓✓	✓✓✓✓✓✓
Increased Pigging or Clearing of Liquids	✓✓✓	✓	✓✓	✓	✓
Tarps or Cold Weather Barriers	✓	✓✓		✓✓	✓✓
Increased Hauling of Fluid	✓✓	✓	✓✓✓	✓✓✓	✓✓
Heated Anti-Freeze		✓			
Heat Trace	✓	✓✓	✓	✓✓✓✓	✓
Hot Oil Trucks	✓				
Insulation	✓✓✓	✓	✓✓	✓✓	
Burial of Lines	✓				
Heat Lamps or heaters	✓✓	✓			✓

A short description of some of these techniques gives a fuller picture of the actions the producers reported having taken:

- Methanol (an anti-freeze type solution) injection or drip is a common practice for freeze protection of wellbores and pipelines. The methanol is injected into the gas stream by chemical injection pumps or enters the pipeline by methanol drips and effectively lowers the freeze point of the gas. Also, separators (used to separate liquids such as oil from the natural gas) may be filled with heated antifreeze to prevent freezing.

- Pigging refers to the practice of using pipeline inspection gauges or "pigs" inside a pipeline to perform various operations without stopping the flow of gas. Pigging operations are conducted on a year-round basis as needed to keep pipelines in working flow conditions. During cold weather their deployment can be increased to remove liquids that might be prone to freezing.

- Cold weather barriers are a relatively simple weather precaution involving the erection of wind walls around certain compressors to block cold winds that exacerbate freezing conditions. Wrapping and insulating surface equipment, injection lines, supply valves, water lines and other locations may also help prevent freezing and the stoppage of fluid flow.

- Hauling oil and produced water from storage tanks is a necessary part of the production process, since tanks that are not emptied can trigger fail safe shut-in devices that will automatically shut down the well. Prior to cold weather, and in anticipation of trucks not being able to reach the facilities, the tanks may be emptied to reduce the likelihood of automatic shut-off.

- Heat can prevent freezing problems; if the gas is never allowed to reach freezing temperatures, ice cannot form. However, heat application involves expensive equipment and requires additional fuel. Heat is also a potential hazard as it can provide an ignition point for the gas. Nonetheless, heat systems can be very effective for a localized freezing problem, and include heating blankets, catalytic heaters, fuel line heaters, or steam systems. Coupling heat systems with insulation is a common technique for protecting flow lines in northern climates.

- Hot oil trucks may be utilized to thaw out flow lines. Typically the hot oil truck will be filled with water, which is then heated and directly sprayed onto lines at risk of freezing.

As it turned out, the various measures producers described as having employed to prepare for the projected cold weather proved inadequate; a substantial number of wells in the affected basins suffered freeze-offs, which had a significant effect on production during the February cold weather event.

Processing Plants

Individual processing plants reported making anywhere from minimal to extensive preparations. Their winterization included:

- Making equipment checks;
- Adding 24-hour staff and adding to nighttime crews;
- Installing insulation;
- Confirming that heat trace equipment was operational;
- Placing tarps as wind breaks and to capture heat;
- Draining water from cooling systems and fluids from piping low points;
- Coordinating with upstream gathering;
- Reviewing past winter events; and
- Installing hot oil heaters.

A representative sampling of processing plant preparations follows.

The Crosstex Energy-affiliated Silver Creek natural gas processing plant in Weatherford, Texas processes Barnett Shale production from the Fort Worth Basin. In preparation for the weather event, operating personnel reportedly performed checks on all equipment, confirmed that all heat trace equipment was turned on prior to the storm, installed tarps on critical equipment, and drained all air supply low points. (Despite these precautions, the plant did experience a shut down of a steam boiler due to a freezing amine/water mixture.)

Enbridge Energy Company, Inc. operates processing plants in east Texas and in north Texas. Generally speaking, operations in both the east Texas and north Texas plants continued in a routine manner prior to the storm.

Energy Transfer Corporation (Energy Transfer) owns and operates the La Grange processing plant in east Texas and the Godley processing plant in north Texas. As part of its general preparation for cold weather at the La Grange plant, Energy Transfer wrapped air regulators and hung tarps around vessels. In late January, an extra operator was placed on duty. With regard to the Godley plant, Energy Transfer had previously installed louvers on all amine still overhead condensers[110] to assist in cold weather operations. A hot oil heater had also been installed in a still condenser to prevent freezing. In addition, prior to the February weather event, Energy Transfer insulated condenser piping at two plants.

[110] The term “amine still overhead condensers” refers to a piece of equipment used to remove the acid gases from the natural gas stream.

MarkWest Energy Partners has two processing plants in Texas. The company reported that both processing facilities are equipped to run during extreme cold weather and that no additional maintenance, insulation or heat tracing was performed prior to the February cold weather event.

Williams Midstream has four processing facilities, the Markham Cryogenic processing plant in Matagorda County, Texas; the Milagro treating plant in San Juan County, New Mexico; the William FS Kutz (Kutz) processing plant in San Juan County, New Mexico; and the Lybrook processing plant in Rio Arriba County, New Mexico. The company reported that the Milagro plant and related facilities are designed to operate in cold weather. Nevertheless, it is standard practice at the plant to check heat tracing controls and piping insulation in the fall months. For the February event, preparations consisted of round-the-clock staffing for certain facilities and adding staffing for the night crew. Standard winter preparation at the Kutz plant reportedly includes coordination with upstream gathering, draining of water cooling systems, placing catalytic heaters into service, installation of wind barriers and group review of past events. In January and February 2011, additional contractor personnel were provided for night operations and additional heat wagons were placed based on needs. The Lybrook plant had also addressed winter preparation prior to 2011 by upgrading and inspecting piping, tracing, and insulation, and by making repairs to hot oil pumps.

Pipelines

Pipelines also prepared for the anticipated cold snap. Typical preparations for both interstate and most intrastate pipelines included:

- Maintaining higher than normal line pack;
- Optimizing compressor operations;
- Enhancing internal communication such as cold weather operational meetings;
- Increasing availability of personnel;
- Cancelling scheduled maintenance where possible; and
- Communicating with customers.

Interstate Pipelines

Individual interstate pipelines reportedly took the following preparations:

EL Paso prepared for the forecasted colder weather by maintaining higher than normal line pack throughout the weekend of January 29 and January 30. (El

Paso considers line pack volumes between 7,200 MMcf and 7,800 MMcf at any given point in time to be in the normal range; at line pack quantities below 7,200 MMcf or above 7,900 MMcf, El Paso generally considers its system to be at or approaching stressed operational conditions.) On Monday afternoon, January 31, El Paso began gas withdrawals from its Washington Ranch Storage Facility, reaching the field's maximum withdrawal rate by the morning of February 1. This was done to compensate for gas supply underperformance in the San Juan and Permian Basins.

Natural Gas Pipeline Company of America (NGPL) uses its Texas facilities to receive gas in Texas and redeliver that gas to markets in the upper Midwest. For February 1 through February 3, NGPL put in place a severe weather operating procedure that provided for management of cold, high winds, ice and snow. This procedure included conferences and communications involving the managers of the gas control and commercial groups of impacted NGPL facilities. Additional actions reportedly taken by the gas control group included adjusting pipeline pressures to meet anticipated load increases, manning facilities on an around-the-clock basis, and carrying out operating procedures designed to keep facilities from freezing.

Transwestern began operating its compression stations to maximize pressures in New Mexico in advance of the cold weather event.

ANR Pipeline Company (ANR) has no facilities in New Mexico, Arizona or California, and only limited facilities in Texas, which are located in the northeast corner of the Texas panhandle (this is the southern-most part of ANR's Southwest Area). To prepare for and respond to operating concerns and ongoing and expected weather events, ANR conducted daily morning operations meetings. An additional "cold weather" operational meeting specifically addressed the week of February 1. ANR reported reduced horsepower at all its Southwest Mainline compressor stations to help flow gas south into the Texas area if scheduled supply decreased, with the aim of maintaining adequate line pack and constant pressures in Texas and Oklahoma.

Intrastate Pipelines

Intrastate pipelines in general employed many of the same preparations as did the interstate pipelines. Reported examples are provided below.

Atmos Pipeline –Texas began building line pack on January 31, and advised shippers to be in hourly and daily balance effective 9:00 AM on February 1. This action assisted with maintaining line pack. Electric generation customers

were advised that deliveries would be limited to Tier 3[111] beginning at 9:00 AM on February 1. Third-party interruptible storage customers were advised that they would be limited to 50 percent withdrawals effective February 1 at 9:00 AM.

Energy Transfer Partners reported ensuring that critical stations were staffed, spare compressors were placed on standby, line pack was increased, and all scheduled maintenance was postponed.

Enterprise Products Partners reported closely monitoring nominations. Staffing coverage was extended in addition to employees' normal schedules. Operations were also reviewed for potential service adjustments that might be required, although none were anticipated.

The Kinder Morgan Texas Pipes' natural gas pipeline operations and gas control group initiated the Kinder Morgan Gas Pipelines' severe weather operating procedure, designed to manage facilities in the event of severe cold, high winds and frozen precipitation. The procedure prescribes conferences and communications among managers and the gas control and commercial groups, and these communications began several days prior to the cold weather event. The gas control group also adjusted pipeline pressures in anticipation of increased load. In the field, some facilities were reportedly staffed around-the-clock, and procedures were put in place to keep facilities from freezing.

Local Distribution Companies

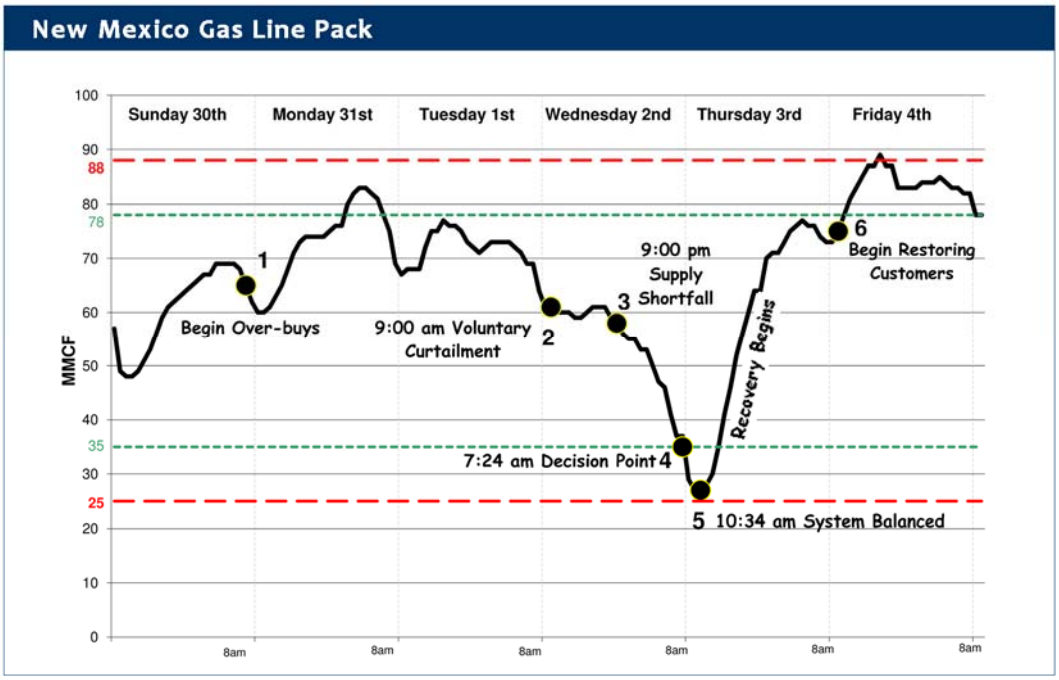
Each of the four LDCs that curtailed customers during the February weather event reported making preparations. They monitored weather forecasts before the event and revised their load forecasts upward. They also increased their purchases of gas to accommodate increased demand and to compensate for freeze-offs, and communicated with suppliers and the pipelines about pending conditions. As conditions worsened, these communications became more frequent.

New Mexico Gas Company packed transmission lines with extra gas, and confirmed that the storage facility it accesses was positioned for withdrawals. Additional gas was purchased for the expected increased demand and in anticipation of freeze-offs. From February 1 through February 3, NMGC had, for each respective day, pre-purchased 36 percent, 55 percent, and 62 percent more gas than its forecasted need. NMGC issued an Alert to all transportation customers concerning the weather forecasts. Given the severity of the anticipated

[111] Tier 3 restrictions applying to electric generating units limit the amount of natural gas the units can take.

storm, at 9:00 AM on February 2, NMGC began requesting that large industrial and commercial customers throughout the state voluntarily reduce or curtail their gas usage. In total, NMGC reported contacting 39 customers, asking for voluntary curtailment.

The following is a chart of NMGC's line pack, juxtaposed with its preparation events.



Source: New Mexico Gas Company

Southwest Gas monitored current weather forecasts on January 30 and January 31, which indicated colder temperatures were expected for southern Arizona. On February 1, a scheduled meeting of engineering and technical services personnel was expanded to include discussions concerning cold weather preparations and system monitoring.

Zia Natural Gas Company (Zia), after observing the dramatically dropping temperatures forecasted for February 1 through February 4 for the state of New Mexico, contacted its primary supplier on January 30 to discuss its supply and receipt options. On February 1, Zia discussed maximum volumes that could be nominated on its pipeline transportation contract.

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V. The Event: Load Shed and Curtailments

When the storm hit the Southwest on February 1, both electric and natural gas facilities began experiencing outages and other production difficulties. These difficulties escalated and ultimately led to load shedding by three electric balancing authorities and service curtailments by four gas LDCs, beginning on February 2. The unfolding events that led to these disruptions, and the conduct of the load shedding and curtailments, are described in this section.

A. Electric

ERCOT, SRP and EPE all engaged in load shedding during the cold weather event. Other electric entities in the area, although they experienced generation losses, were able to avoid load shedding (with the exception of PNM, which experienced some small, localized load loss from transmission issues). Each affected utility's actions are discussed separately below. (All times referenced are expressed in local time.)

ERCOT

ERCOT's required responsive reserve level is 2300 MW.[112] This is the amount that ERCOT has determined to be necessary on its system to ensure that the system will maintain frequency and voltage stability; that thermal and voltage limits will remain within applicable ratings; and that there will be no loss of demand, curtailment of firm transfers, or cascading outages.[113] If reserves drop below specified amounts, ERCOT is required by its Protocols to take actions to bring them up again, including the shedding of load.

ERCOT has specified in its Protocols certain triggering events that require taking action to prevent the uncontrolled loss of firm load. In doing so, it has patterned its emergency alert protocol on the Reliability Standard that prescribes

[112] As discussed in the section of this report entitled "Preparations for the Storm," this amount was based on a 1988 study designed to determine the amount of reserves needed to prevent shedding of firm load if ERCOT's two largest contingencies occurred.

[113] This minimum level of reserves is based on an N-2 criterion, a more conservative requirement than that required by the FERC-approved Reliability Standard BAL-002-0 R3.1, which requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." ERCOT's N-1 largest single contingency would be the loss of a nuclear-powered generating unit at the South Texas Nuclear Project, rated at 1354 MW.

an energy emergency alert procedure.[114] Both the Reliability Standard and the ERCOT Protocol categorize these triggering events into three levels, Levels 1, 2, and 3; ERCOT further subdivides Level 2 into 2A and 2B.

ERCOT had to make decisions throughout the morning of February 2 regarding the declaration of these various emergency alert levels and actions. That was particularly so with respect to Level 3, which requires the shedding of firm load.

Energy Emergency Alerts

Reliability Standard EOP-002-2.1 prescribes the use of an energy emergency alert (EEA) procedure when a load serving entity is unable to meet its customers' expected energy requirements. These energy emergencies are declared by the load serving entity's reliability coordinator, and are categorized by level of severity:

- EEA 1 - For conditions where all available resources are committed to meet firm load and reserves, all non-firm sales have been curtailed, and the entity is still concerned about sustaining its operating reserves.

- EEA 2 - For conditions when the entity is no longer able to meet expected energy requirements, and is designated an Energy Deficient Entity.

  The entity is to do the following, as time permits:

  Public appeals to reduce demand,
  Voltage reduction,
  Interruption of non-firm loads,
  Demand-side management, and
  Utility load conservation measures.

  Other entities are to provide emergency assistance as appropriate and available.

- EEA 3 - For conditions when the energy available to the Energy Deficient Entity is only accessible with actions taken to increase transmission transfer capabilities.

  At this point, firm load interruption is imminent or in progress.

(cont'd)

[114] *See* Reliability Standard EOP-002-2.1 (Capacity and Energy Emergencies).

ERCOT:

ERCOT has particularized this emergency energy alert system to the requirements of its own system. It is required under its Protocols to perform certain actions upon the occurrence of distinct triggering events. These are as follows:

Level / Triggering Event / System Operations Actions

- EEA 1 — Less than 2300 MW of Reserves:
  Use capacity available from DC ties, dispatch uncommitted units.
- EEA 2A — Less than 1750 MW of Reserves:
  Deploy Load Resources (LR); begin block-load transfers of load to neighboring grids.
- EEA 2B — To maintain system frequency at 60 Hz or reserves trending downward or not available:
  Deploy Emergency Interruptible Loads (EILS) if available.
- EEA 3 — To maintain system frequency at 59.8 Hz or greater:
  Instruct transmission operators to shed load via rotating outages in blocks of 100 MW.

As discussed in the preceding section of this report, "Preparations for the Storm," severe weather conditions on February 1 precipitated numerous forced generator outages within ERCOT's footprint. By midnight on February 1, 6022 MW of generation capacity was unavailable due to weather-related forced outages and derates, and conditions worsened overnight.

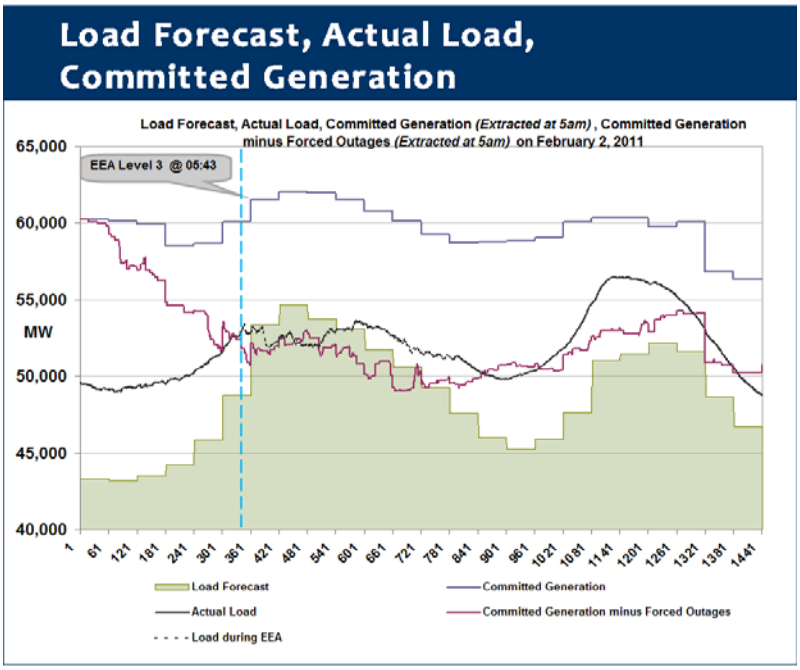
Generation Shortfalls on February 2

By 3:00 AM on February 2, responsive reserves had dropped below 3000 MW. ERCOT issued both an OCN and an Advisory to market participants, notifying them of the severe weather and the falling reserve level.[115] It followed this communication with an emailed report to the PUCT about the falling reserves.

[115] The communication steps taken by ERCOT appear to be consistent with its Operating Guidelines and Protocols. However, a number of transmission providers have stated they could have been better prepared to implement their required load shed if they had had more information about ERCOT's deteriorating system status much earlier during the overnight period of February

At 4:30 AM, ERCOT operators instructed deployment of 1840 MW of non-spinning reserves, principally combustion turbines. (Non-spinning reserves require 30 minutes or longer to come on-line or to ramp up to their next block of power output.) Ten of the units, or a total of 669 MW of capacity, were unable to respond, many because they failed to start. By 5:08 AM, reserves had dropped below 2500 MW, and ERCOT issued a Watch.

ERCOT calculates its operating reserves on a real-time basis by comparing metered demand with its available generation resources. At the same time generation was dropping off during the morning of February 2, demand was rising. The cold weather and winds were placing extraordinary demands for power on the system, and load was running consistently higher than had been forecasted for the day. In fact, at 5:20 AM the demand was 2760 MW higher than on any other day in the history of the ERCOT region at that hour, and was rapidly climbing.[116] The following chart, prepared by TRE, compares actual demand with forecasted demand.



Source: TRE

The actual peak demand for the day, which typically occurs in the morning around 8:00 AM, was artificially skewed downward because of the load shed. The

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1 to February 2. They would have liked to have received such information as soon as ERCOT began seeing a high number of forced generator outages.

[116] Potomac Economics, Ltd., *Investigation of the ERCOT Energy Emergency Alert Level 3 on February 2, 2011*, at 3 (April 21, 2011) (Potomac Report), *available at* http://www.puc.state.tx.us/files/IMM_Report_Events_020211.pdf.

IMM (Potomac Economics, Ltd.), the market monitor for ERCOT, estimated that the demand that would have materialized absent any load reductions or curtailments would have peaked at 59,000 MW, just after 7:00 AM.[117] This estimate suggests that the high demands already being placed on the system in the early morning hours would likely have continued to escalate.

At 5:09 AM, reserves dropped below 2300 MW, the triggering event for ERCOT's declaration of an EEA 1 (although it was not declared, presumably because events were moving so swiftly). At 5:20 AM, responsive reserves had dropped below 1750 MW, and ERCOT issued an EEA 2A. It also deployed 888.5 MW of Load Resources, with 881.7 MW responding. Load Resources are counted as responsive reserves and, as such, their deployment reduces ERCOT's responsive capability. In this case, however, two factors worked to offset this reduction:

- The dropping of 881.7 MW of load increased the margin between generation and load, and ERCOT allowed a fraction of this increase to be allocated to responsive reserves. (The fraction ERCOT allots is typically 20 percent, but varies based on the specific generation online at any given time.)

- The Load Resources were being deployed over a 10-minute interval during which some additional generation was actually coming online, despite all the problems on the system.

As a result of these factors, for a short time while Load Resources were being deployed, responsive reserves actually increased by about 200 MW. It was not long, however, before additional forced outages and derates of generation, combined with the normal pick-up of morning demand, again decreased the level of responsive reserves.[118]

At 5:26 AM, ERCOT deployed RRS reserves, a form of interruptible load, which briefly raised the reserve level to above 1400 MW.

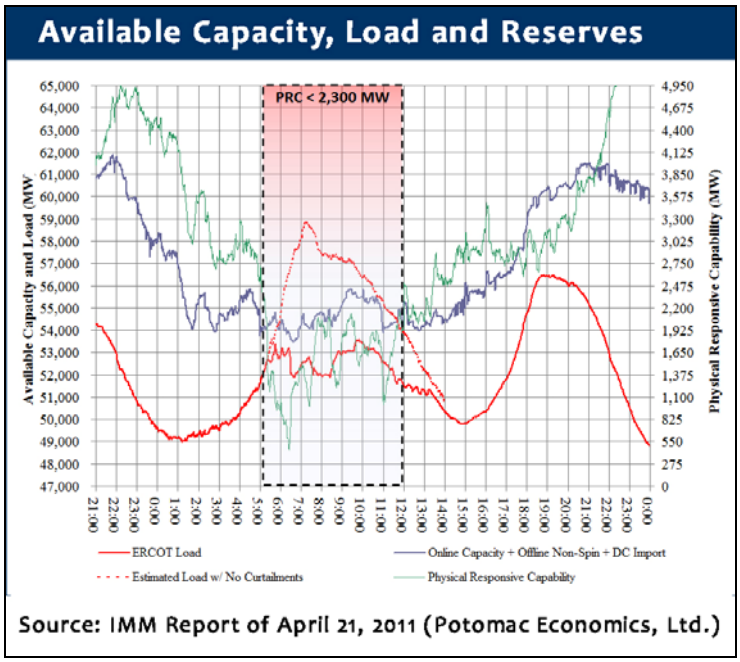
[117] Potomac Report at 3-5. The estimate was based on several factors, including the actual load and rate of load increase prior to the implementation of the first load curtailments, the load shape on similar days, and ERCOT load forecasts produced just after 3:00 AM on the morning of February 2.

[118] Responsive reserves would ultimately fall to a low point of 447 MW at 6:25 AM, after the load shed had already begun.

More units, however, continued to trip off-line. Responsive reserves briefly dipped below 1354 MW (the N-1 contingency reserve level required for safe operation of the system) twice before 5:40 AM. At that time, the responsive reserves dropped below the N-1 contingency level for an extended 73 minute period.[119]

At 5:43 AM, ERCOT declared an EEA 3 and began the process of shedding load.

The following graph[120] indicates the relationship between ERCOT's available capacity, loads and reserves throughout the day.



Counting both February 1 and February 2, a total of 193 generating units in ERCOT tripped, had derates, or failed to start, representing a loss of 29,729 MW of capacity.[121] At the lowest point of available generation, which occurred at 6:12

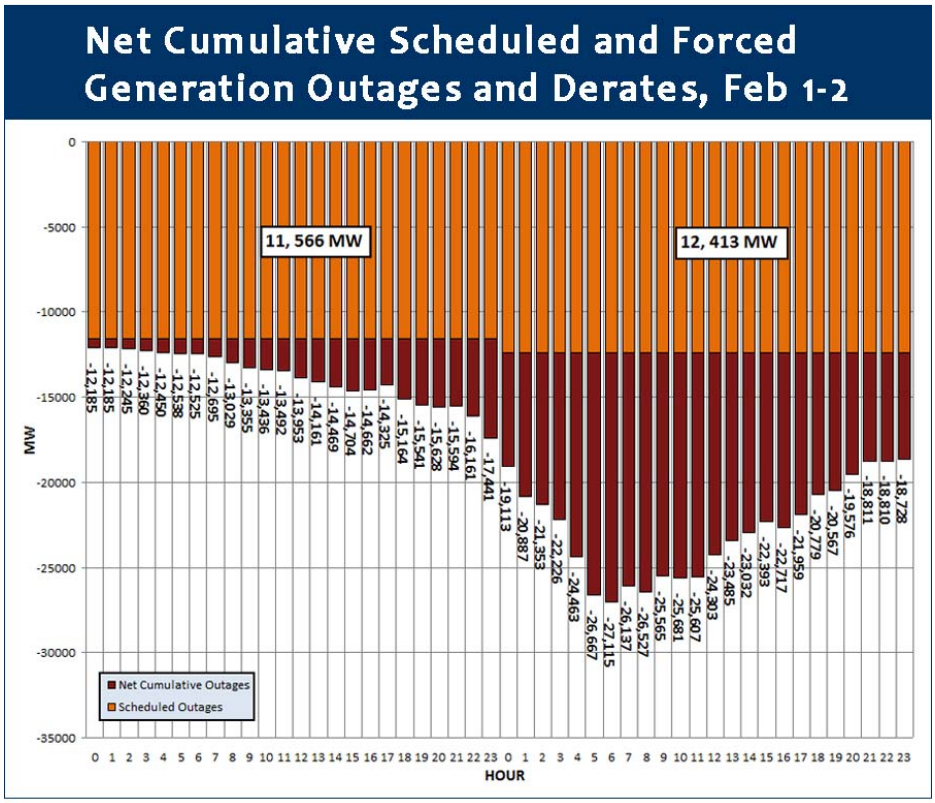
[119] There were six times during the morning of February 2 when ERCOT's response reserves fell below 1354 MW. Those times are: 5:23-5:29 AM, 5:31-5:32 AM, 5:40-6:52 AM, 7:11-7:30 AM, 8:39-8:52 AM, and 10:58-11:15 AM, for a total of two hours and 14 minutes, with the longest interval 73 minutes. (Calculation of the time periods includes the beginning and ending minutes.)

[120] Potomac Report at 6.

[121] This is a gross cumulative number; a unit is counted as having failed regardless of whether it came back online at some point during the event. This measurement gives an

AM, there were 14,702 MW of generation offline from such trips, derates, or failures to start. Adding that number to the scheduled outages for the day of 12,413 MW, means that 27,115 MW, or approximately one-third of the total ERCOT fleet, was unavailable to provide power.

The following two charts depict the net and gross cumulative capacity reduction resulting from forced outages, derates, and failures to start, as added to the scheduled outages, for these two days.[122] Comparing these numbers to total ERCOT generation of approximately 79,700 MW[123] gives a picture of the magnitude of the generation loss, as well as of the difficulties that confronted ERCOT's operators on those two days.



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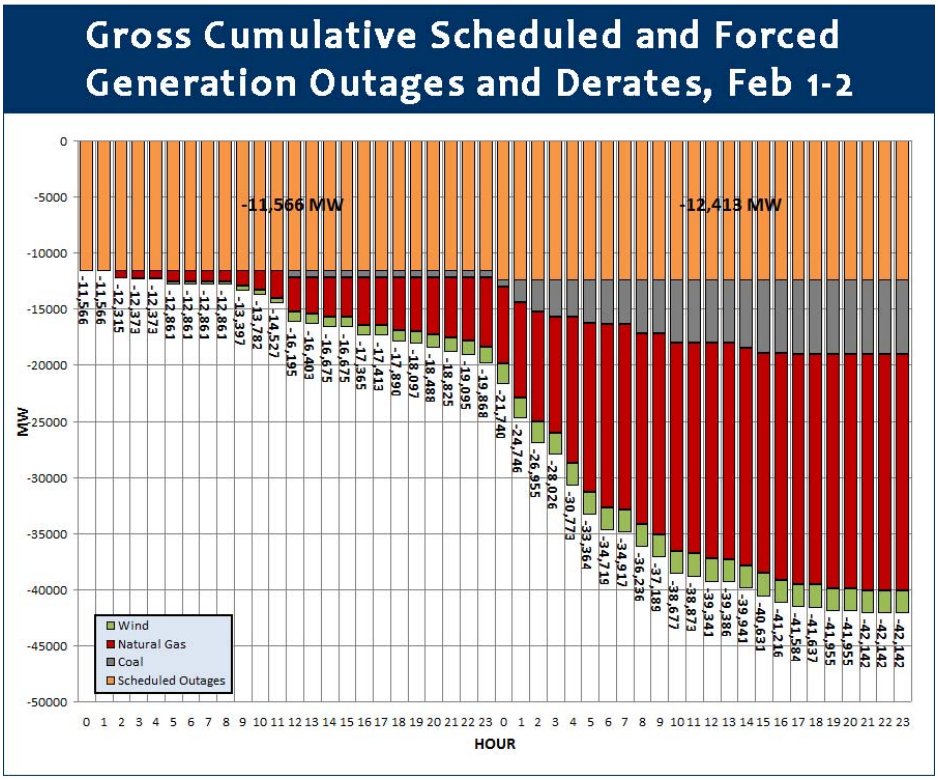
indication of the total amount of capacity that failed during the event (rather than the amount offline at any given point in time).

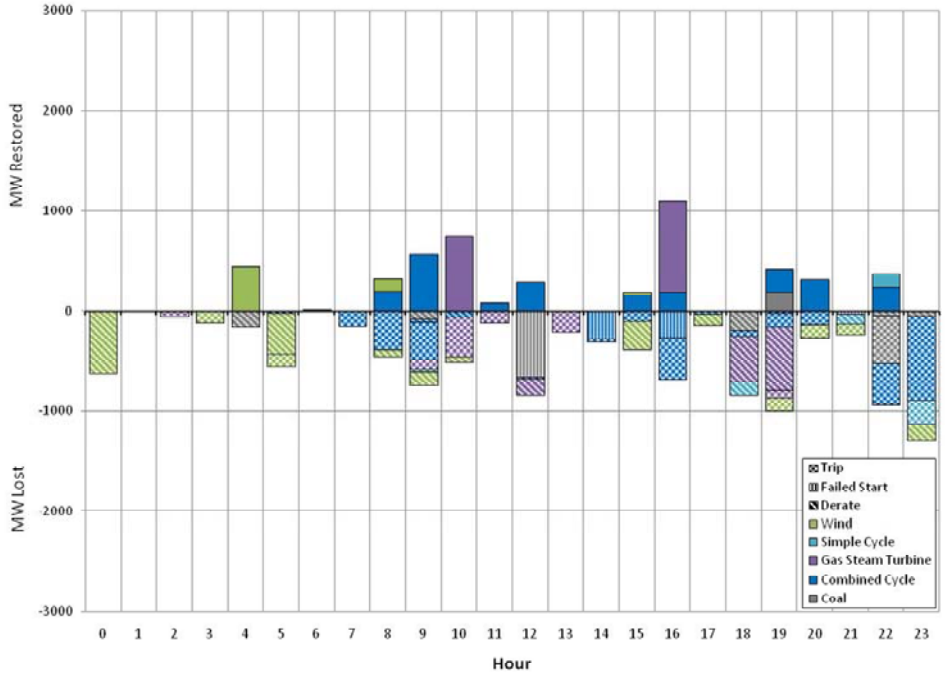
[122] The first chart depicts net outages after subtracting out units that came back online. The second chart shows cumulative outages with no adjustment for units that came back online.

[123] The 79,700 MW number represents total ERCOT fleet capacity, online and offline, measured at 8:00 AM on February 2 (it does not include imports over the DC ties). The wind power capacity embedded in that number, as well as in the capacity reductions for the outages, derates, and failures to start, has been adjusted to reflect the actual hourly wind speed conditions (in lieu of using straight "nameplate" values which pertain only to optimum wind speeds that produce full rated output).

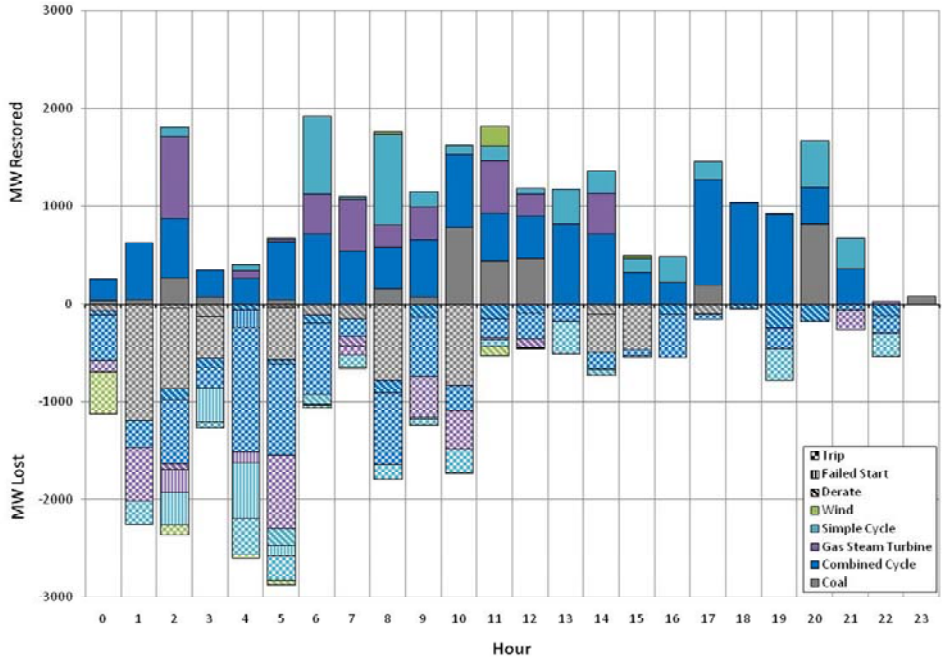


The task force has also prepared charts for February 1 and February 2 that depict, hour by hour, the MWs that failed and the MWs that were restored, both by fuel type and by type of failure (trip, derate, or failure to start). These charts give a running picture of the fluctuations in available capacity, by fuel type, at any given point in time throughout the event.

Capacity Fluctuations by Fuel Type on Feb. 1, 2011



Capacity Fluctuations by Fuel Type on Feb. 2, 2011



The various reasons for the outages, derates and failures to start that occurred during the event (the majority of which were weather-related, either

directly or indirectly) are discussed in the following section of this report entitled "Causes of the Outages and Supply Disruptions."

Adjusted Wind Power Capacity

The capacity of a wind power installation is typically reported on a "nameplate" basis, with the nameplate value representing what the facility can produce when the actual wind speed is optimum for the particular turbine design. When a wind farm is offline on a scheduled or forced outage, the capacity unavailable to the system is also typically reported on a nameplate basis; the same is true for partial outages, which are reported as derates (collectively, nameplate outage value).

The actual wind speed, however, is seldom sufficient to produce full nameplate output simultaneously throughout ERCOT. Therefore, the nameplate outage values must be adjusted downward to realistically represent the impact of outages and derates of individual wind facilities.

Adjusted Outages and Derates

The total installed wind power nameplate capacity in ERCOT is 9321 MW**.** If the aggregate nameplate outage values reported during February 1 and February 2 are subtracted from this 9321 MW total, nameplate available values are obtained on an hourly basis. Dividing the actual measured aggregate wind power output for any given hour by the nameplate available value for the same hour produces a percentage output that reflects how strongly the wind is blowing compared to full-output levels. Over the course of February 1 through February 2, that percentage varied from 40 to 75 percent (which is atypically high). To determine adjusted outage values, the percentage for any given hour is applied to the nameplate outage value for that same hour. For example, if the reported nameplate outage value for the 5:00 AM hour was 3200 MW, and the percentage output was 50 percent, the adjusted outage value is 1600 MW. This value more realistically represents the additional wind power that would have been supplied to the ERCOT grid had it not been for the wind farm outages and derates.

Although this method does not take into account the fact that the wind speed at a specific location where a forced outage has occurred may or may not correlate with the average value, any errors at individual locations should tend to offset one another. The method also assumes that the reports of forced outages and derates were made on a timely basis, which may or may not have been the case.

(cont'd)

Adjusted Capacity

NERC used 8.7 percent of nameplate capacity in calculating the contribution of wind power to existing generation in its 2010-2011 Winter Assessment of the TRE region. This is a planning number that has merit for the seasonal overview, but is not applicable to the high wind conditions of February 1through February 2. Therefore, in determining the wind power capacity in ERCOT for purposes of this inquiry, the task force multiplied the total installed capacity of 9321 MW by the percentage of output actually achieved by those facilities that remained in service, compared to nameplate capacity. The resulting adjusted capacity represents what the total wind power output would have been in ERCOT had there not been any outages or derates during February 1 through February 2. Since the percentage varies with the wind speed, adjusted capacity values were calculated hourly. At 8:00 AM on February 2, the percentage of output vs. nameplate was 57 percent, yielding an adjusted capacity of 5313 MW (0.57 x 9321 MW). This number was then used as wind power's contribution to the total generation fleet. Counting all units, both online and off, that total came to 79,658 MW for the 8:00 AM hour. (Since the adjusted capacity value changes hourly based on wind speed, so too will the numerical size, in MWs, of the total generation fleet.)

The Load Shed Decision

Load shedding is implemented to correct an electrical power imbalance if load exceeds supply and system operators cannot bring the system back into balance through other measures. Load shedding may be used to reduce an overload condition (such as when thermal limits on a transmission line are exceeded), to recover from an under-frequency condition, or to return voltage to a normal level. The operation can be manual (operator-initiated) or automatic (relay- initiated), depending on how quickly the frequency is decaying or the voltage is falling. For slowly declining frequency or voltage issues, the manual option is usually chosen. For rapidly declining frequency or voltage, the automatic option will respond without operator intervention.

ERCOT utilized operator-initiated load shedding on February 2, which preserved the system's ability to implement automatic load shedding had system conditions continued to deteriorate. Had ERCOT not instituted manual load shedding, automatic under-frequency load shedding would have been a last resort before a possible system collapse. Manual load shedding also helped raise the frequency levels, preventing damage to generator turbines.

The task force considered the question of whether ERCOT's decision to manually shed load prevented more extensive blackouts than were experienced as a result of the load shed itself. While a definitive answer would require extensive

modeling and data inputs, the task force concluded, based on the information available, that ERCOT's declaration of an EEA 3 probably prevented widespread, uncontrolled blackouts throughout the ERCOT Interconnection. Because ERCOT operates as a functionally separate interconnection from its neighboring Eastern and Western Interconnections and is linked only by asynchronous ties, the blackouts would not have propagated further.[124]

Frequency Response and Automatic Under-Frequency Load Shedding

Frequency as a measure of the reliability status of a power system can be likened to pulse or heart rate as a measure of human health. It provides a key indicator of the overall integrity of operations. Maintaining frequency requires balancing a system's aggregate generation output to load moment-to-moment. It also requires having sufficient reserves available at all times to withstand the sudden loss of the largest generator on the system, in order to instantaneously make up for the loss of power and thus reestablish balance.

In spite of the enormous amount of generation that was forced off line in successive waves in ERCOT on February 1 and February 2, especially during the overnight and early morning hours between the two days, the overall frequency response of the system was not problematic during the event. Nonetheless, the need to maintain frequency to prevent a collapse of the system was the fundamental driving force behind ERCOT's decision to shed firm load.

Because ERCOT is not synchronously connected to either the Eastern or Western Interconnections, all frequency response must come from internal resources. And because ERCOT is smaller than the other interconnections, the loss of a generator results in a steeper frequency decline, necessitating a more robust frequency response. For this reason, in 1988 ERCOT established a minimum responsive reserve requirement of 2300 MW, based on an N-2 criterion covering the loss of the two largest generators in ERCOT (one nuclear-powered unit and the next largest unit on the system). This is a larger reserve than the N-1 criterion required by Reliability Standard BAL-002-0 R3.1. On the morning of

(cont'd)

[124] NERC has prepared a study on the reliability implications of the February cold weather event entitled "Analyses of Reliability Impacts on the Bulk Power System." The study discusses the impacts on the WECC Interconnection of the events in SRP, EPE, and PNM, and presents an analysis of frequency response performance during the event by the Eastern Interconnection and the ERCOT Interconnection. NERC plans to make the study publicly available.

February 2, 2011, the largest single contingency was an online nuclear-powered generating unit with a capability of 1354 MW.

ERCOT maintains and closely monitors its responsive reserve levels (also referred to by ERCOT as its Physical Response Capability, or PRC), to comply both with its own 2300 MW criterion and with the 1354 MW minimum criterion.

ERCOT relies on demand side load resources to provide up to 50 percent (1150 MW) of its 2300 MW responsive reserve requirement. These resources automatically disconnect when the frequency declines to 59.7 Hz. The purpose of the responsive reserves, both generation and load, is to arrest frequency declines before they reach 59.3 Hz (the trigger threshold for the first block of automatic under-frequency load shedding (UFLS)), and to restore frequency to 60 Hz within a few minutes following an event. Should either generation or load resources be deployed manually by system operators, they are no longer available to provide frequency response.

Between 5:15 AM and 1:20 PM on February 2, responsive reserves dropped below the 2300 MW N-2 criterion three separate times, of varying durations. Ultimately, responsive reserves dropped below the 1354 MW N-1 criterion. This occurred six separate times between 5:23 AM and 11:15 AM, for a combined total of 134 minutes, with the longest interval being 73 minutes. During the times when responsive reserves were below 1354 MW, had the largest generator tripped, reserves would have been insufficient to reestablish the balance between generation and load. The result would have been an inexorable decline in frequency which, when it reached 59.3 Hz per second, would have triggered the first block of automatic under-frequency load shedding, which would have dropped five percent of the system load, or roughly 2600 MW.

Even though the under-frequency load shedding would have tripped automatically, this response would have taken out firm load and would be in addition to any firm load that operators may have already shed, starting with the first directive ERCOT issued at 5:43 AM. Depending on the particular circumstances surrounding the moment of activation of the automatic under-frequency load shedding, it is possible that an overvoltage condition could have occurred in one or more localized areas, that frequency could have significantly overshot the 60 Hz norm, or that other electrical perturbations could have developed that would have resulted in the tripping of even more generation. Only a detailed dynamic simulation could answer the question as to how widespread the February 2 blackout would have been had the automatic under-frequency load shedding been triggered.

ERCOT's Black Start Capability

If the load shed had not prevented an ERCOT-wide blackout, the outages would not only have been more widespread, they might have been of a much longer duration. The task force reviewed the state of ERCOT's black start units to determine whether they could have promptly brought the system back had a collapse occurred. "Black start" refers to restarting the system after a major portion of the electrical network has been de-energized, and generators that have black start capability are those that can be started independently and without external power.

ERCOT has 15 primary and six alternate black start generators. During the event, roughly half of these generators were unavailable: two (totaling 97 MW of capacity) were on planned outage; four (totaling 141 MW) failed to start due to the extreme cold weather; three (totaling 423 MW) tripped offline after starting due to freezing equipment; and one (26 MW) tripped offline due to natural gas fuel curtailment. Had a total blackout of the ERCOT system occurred, the unavailability of 10 of ERCOT's 21 (primary and alternate) black start resources, comprising 687 MW out of a total 1150 MW of black start capacity, could have jeopardized ERCOT's ability to promptly restore the system.

The Load Shed Process

ERCOT accomplishes a controlled load shed by issuing directives to its transmission providers,[125] ordering the load shed to proceed in defined blocks of power (each transmission provider being responsible for its allocated share of the total). On February 2, ERCOT issued its first load shed directive at 5:43 AM and its third and last at 6:23 AM. In total, it directed that 4000 MW be shed.

ERCOT began load restoration at 7:57 AM, and firm load was fully restored at 1:07 PM.

[125] "Transmission provider" is a generic term. ERCOT uses "transmission service provider" to mean an entity that owns or operates transmission facilities to transmit electricity and provide transmission service on the ERCOT grid. NERC uses different terminology to describe the various types of transmission providers, including "transmission service provider," "transmission operator," and "transmission owner." (The definitions of these terms can be found in the appendix entitled "Categories of NERC Registered Entities.") Under NERC terminology, ERCOT is the only "transmission service provider" for its Interconnection. To avoid confusion, the term "transmission provider" will be generally used in the narrative portions of this report to refer to any of those various categories of entities who provide transmission service and who were directed to shed load and took the necessary actions to do so (including load shedding both within and outside of ERCOT).

The actual load shed process and eventual restoration of the system to an EEA 0 state[126] proceeded as follows:

ERCOT issued its first instruction at 5:43 AM, ordering a load shed of 1000 MW. Shortly thereafter, ERCOT also deployed 384.2 MW of Emergency Interruptible Load Service, ERCOT's form of demand response.[127]

At 6:04 AM ERCOT directed the transmission providers to shed an additional 1000 MW of load. In the next second, 6:05 AM, ERCOT's frequency dropped to 59.576 Hz, its lowest point during the event.

At 6:23 AM ERCOT issued its third and last load shed directive, directing the transmission providers to shed an additional 2000 MW. This resulted in a total load shed directive of 4000 MW.

As the transmission providers were implementing ERCOT's directives to shed load, additional generation became unavailable; between 5:45 and 6:30 AM, 18 generating units tripped offline, were derated, or failed to start, totaling 1643 MW of output. (During this same time, 12 units came back online, totaling 774 MW.)

At 6:25 AM, ERCOT's reserve level dipped to 447 MW, its lowest point of the day.

At 6:59 AM, ERCOT issued a media appeal for energy conservation. This was the first notification to the public of the problems ERCOT was experiencing on its system.[128]

At 7:57 AM, ERCOT issued its first load restoration directive, beginning with a 500 MW block. Three seconds later, a combined cycle unit loaded at 77

[126] "EEA 0" signifies a normal state of operation.

[127] While some EILS customers failed to reduce load as contracted (thus exposing themselves to potential penalties), others responded with a load reduction in excess of their contracted amount. The net result was that total EILS load reduction fell short of obligated levels on February 2 in only one fifteen-minute interval.

[128] ERCOT has acknowledged that it could improve its communications with the general public, which it suggests could be accomplished through use of an automated system for contacting the media, deployment of representatives to meet with the media, and through designation of supplemental communications staff to answer phone inquiries during a period of emergency.

MW tripped offline, causing reserve levels to again fall below 1354 MW. However, ERCOT did not shed any additional load.

At 8:22 AM, ERCOT directed the transmission providers to restore another 500 MW block of shed load. ERCOT would issue six more load restoration directives over the course of the next several hours, completing the process at 1:07 PM.[129]

At 8:53 AM, ERCOT deployed an additional 83.5 MW of EILS, at which point reserves increased above the 1354 MW limit.

At 9:25 AM, ERCOT called all QSEs and instructed them not to take any resources offline unless so instructed.

Additional units, including an 849 MW coal unit, continued to trip offline. At 10:58 AM, reserves again dropped below the 1354 MW limit. This situation lasted until 11:15 AM.

At 12:12 PM, ERCOT reported to the QSEs that the Texas Commission on Environmental Quality (TCEQ) had issued a waiver for certain air permitting requirements that might otherwise have prevented generators from producing power during the emergency. (The TCEQ's actual communication did not mention a waiver, but rather indicated it would exercise its "enforcement discretion.")

At 1:57 PM, ERCOT recalled RRS Block 2 Load Resources (463 MW).

At 2:01 PM, ERCOT returned to a state of EEA 2B.

At 2:55 PM, ERCOT recalled RRS Block 1 Load Resources (437 MW).

At 3:14 PM, ERCOT returned to a state of EEA 2A. Reserve levels rose to approximately 2900 MW.

At 7:15 PM, ERCOT set a record winter peak demand of 56,480 MW.

On February 3, at 10:00 AM, ERCOT declared a state of EEA 0 and recalled all EILS loads.

[129] Directives were issued in 500 MW blocks at 9:25 AM, 11:39 AM, 12:04 PM, 12:25 PM, 12:49 PM, and 1:07 PM.

Summing every transmission provider's peak load shed amount (which did not occur at the same time), the cumulative load shed on February 2 was 5411.6 MW. The largest amount of load shed at one point in time (8:02 AM) was 4947.9 MW.[130]

The load shed process by ERCOT's transmission providers is discussed below.

Conduct of the Load Shed by ERCOT's Transmission Providers

ERCOT communicated its oral dispatch instructions to shed load via hotline calls. The percentage of the total requirement that is to be shed by each transmission provider is based on the transmission provider's previous year peak load, as reported to ERCOT.[131] Under ERCOT's Nodal Operating Guides, transmission providers have 30 minutes to shed their required share of load if the curtailment is implemented remotely by SCADA system, and one hour if implemented by dispatch of personnel into the field to manually disconnect feeders.[132]

Load Shed Program Design

Each transmission provider in ERCOT is responsible for determining how load will be shed in order to meet its load shed obligation.[133] The larger transmission providers interviewed by the task force make use of automated systems for shedding load. All transmission providers interviewed pre-designated feeders or blocks that are available for manual load shed. Transmission providers generally take into account the following factors in setting up their load shed system:

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[130] Based on TRE data supplied to the task force. (This number does not include Greenville, for which comparable data was not available. Adding 8.8 MW for Greenville would bring the total to 4956.7 MW).

[131] See ERCOT Nodal Operating Guides: Emergency Operation § 4.5.3(5) (July 1, 2011), *available at* http://www.ercot.com/mktrules/guides/noperating/cur.

[132] *Id.* at § 4.5.3(7)(a)-(b). These time frames do not apply if the load shed directive exceeds 1000 MW, as was the case for ERCOT's last load shed instruction on Feb. 2, 2011. *Id*. at § 4.5.3(7)(c).

[133] Actual implementation of load shedding is carried out at the distribution level, which may be done through a separate division of the transmission provider or through a separate, affiliated entity (*e.g.*, a member distribution cooperative of a generation and transmission cooperative). This extra layer of communication appears to have caused some delay in the initiation of the load shed process in at least some cases.

1. Minimizing customer disruptions through target outage rotation periods. Transmission providers interviewed utilize a load-shed scheme with a targeted rotation period between 15 minutes at the low end and 30-45 minutes at the high end. During the February 2 event, transmission providers reported difficulties maintaining a short (15-minute) rotation period over the course of the morning, as ERCOT raised their load shed obligation to the highest levels most transmission providers had experienced. Transmission providers reported having to go through their rotation schedule multiple times, and some transmission providers expressed concern that a limited number of customer groups had to carry a disproportionate amount of the load-shed burden.[134]

2. Avoidance of feeders or lines reserved for under-frequency load shedding (UFLS) requirements. All transmission providers interviewed indicated that UFLS blocks[135] are not generally included as available feeders for manual load shedding under their load shed procedures. However, one transmission provider discovered during the February 2 load shed event that some lines designated as available for manual load shed were also designated for UFLS. Except for this one overlap in blocks, the transmission providers interviewed were able to fully meet their load-shedding obligations while maintaining the required 25 percent of load reserved for UFLS. There were no reported instances of automatic under-frequency trips during the February 2 event.

3. Exemptions for critical customers. Transmission providers utilize a variety of approaches for identifying critical customers or loads that are either exempt from rolling outages or are given a higher priority for preservation of service. Customers that typically receive some form of exemption or higher priority include hospitals, airports, and

[134] TRE Report at 41; materials provided to the task force by transmission operators.

[135] Distribution service providers in ERCOT are required to set up relays to automatically trip load as frequency falls, as follows: (1) at 59.3 Hz, a minimum of 5 percent of load must trip; (2) at 58.9 Hz, an additional 10 percent of load must trip; and (3) at 58.5 HZ, an additional 10 percent of load must trip, *i.e.*, the distribution service providers must have at least 25 percent of its load available for UFLS. (This is independent of any manual load shedding directives.) ERCOT Nodal Operating Guides Section 2: System operations and Control Requirements at 2.6.1(1) and (2). Some transmission providers use these same blocks of load for automatic under-voltage protection. (Note that NERC uses the term "distribution provider" to describe this type of entity. This report will use the term "distribution service provider" throughout to avoid confusion.)

other facilities that may affect public safety, such as police stations.[136] Some transmission providers interviewed indicated that they have a process for checking with gas customers for possible critical loads, such as gas compressor facilities without backup generation. But most acknowledged that the process for identifying "critical" gas facilities could be better standardized or otherwise improved.

4. Exemption of large loads and networks needed for system stability. Major downtown areas are generally exempted from the load shed plan, as cutting off service to these heavily networked systems could affect system stability. Large, high-voltage industrial loads are also generally not available for manual load shedding due to system stability concerns.[137]

After taking into account UFLS blocks, critical/exempt customers, and other load that is not appropriate for manual load shedding, the interviewed transmission providers indicated that they had between 30 percent and 70 percent of their total load available for manual load shedding.

Experience on February 2, 2011

The transmission providers' overall load shed response (in MW) was beyond the minimum required by ERCOT and was adequate to protect system frequency.

Most of the larger transmission providers interviewed were able to shed load within a few minutes of receiving each ERCOT directive, and utilized some form of automated system for shedding load. These systems were designed to

[136] The State of Texas also requires transmission providers and distribution service providers to provide notification of interruptions or suspensions of service under certain conditions (set out in their retail delivery tariffs) to customers that meet the criteria for designation as a Critical Load Public Safety Customer (hospitals, police stations, fire stations, and critical water and wastewater facilities), Critical Load Industrial Customer, Chronic Condition Residential Customer, or Critical Care Residential Customer. 16 TEX. ADMIN. CODE § 25.497 (2011).

[137] Some of these high-voltage industrial loads may be under contract as Emergency Interruptible Load Service (EILS) or providing ancillary services (RRS) as Non-Controllable Load Resources (NCLR). *See* TRE Report at 42-44. In such case, those resources would be (and were) called upon by ERCOT through the relevant QSE (at 5:49 for EILS and at 5:20 for NCLR), something that is not communicated to or controlled by the transmission providers or distribution service providers.

look at actual load on the feeders in real time, and were designed to rotate customer blocks by restoring service feeder-by-feeder as the pre-determined rotation period expired. These systems were also designed to ensure that the total curtailment obligation is maintained or exceeded at all times, by restoring a given feeder only *after* another feeder or feeders with off-setting load have been dropped in the next block. At least one of the automated systems in use during the event was designed to take into account cold load pickup prior to restoration of feeders,[138] and therefore may have generated a greater reported level of over-shedding for limited periods of time during the rotation process.[139]

Other transmission and distribution service providers used less sophisticated methods for shedding load during the event, including having a dispatcher record load amounts prior to dropping a given block to calculate the total amount to be reported to ERCOT as having been shed, and using color-coded circuit maps to select lines to be shed.

All but four transmission providers were able to meet or exceed their load shed obligations within 30 minutes of each oral dispatch instruction from ERCOT. Three of the four transmission providers did meet their full load shed obligations at a later point in time. The fourth transmission provider contended that it had not received the dispatch instruction.

Effect of Load Shed on Gas Delivery or Supply

At approximately 8:00 AM on February 2, ERCOT notified all transmission providers that gas companies were reporting low gas pressures, and requested that they confirm that no gas company feeds were included in their

[138] Cold load pickup is a phenomenon that takes place when a distribution circuit is re-energized following an extended outage of that circuit. Cold load pickup is a composite of two conditions: inrush and loss of load diversity. *Cold Load Pickup Issues: A Report to the Line Protection Subcommittee of the Power System Relay Committee of the IEEE Power Engineering Society*, May 16, 2008, § 2.1, at 3, *available at* http://www.pes-psrc.org/Reports/Cold_Load_Pickup_Issues_Report.pdf .

[139] One transmission provider's automated system includes an expectation of a 60 percent increase in load on any feeder coming off of its pre-determined outage period, and therefore requires that feeders in the next block must cover the expected increase before the first feeder can be restored. That transmission provider did report peak load shed amounts well above its requirement (about 49 percent over the required amount at one point), but attributed the reported over-shedding to several factors in addition to the cold load pickup assumptions used, including (1) restoration failure of a certain percentage of breakers; and (2) loads that did not come back on-line until manually re-set, including certain gas compressors.

outage rotation feeders.[140] At 9:25 AM, as part of its third directive to restore 500 MW of load, ERCOT requested that transmission providers serving west Texas concentrate their restoration efforts in that region due to concerns about the impact of the outages on gas compressor facilities. At 10:45 AM, ERCOT notified some transmission providers that gas compressor stations in two west Texas counties were still without power, and requested that service be restored to those counties as soon as possible.[141] In addition, some transmission providers reported additional requests from ERCOT about restoring power to specific gas facilities or regions, but noted that ERCOT did not appear to have reliable or current information as to which transmission or distribution service provider was providing electric service to those facilities.

The task force found that transmission providers currently have only limited information on overall system conditions in ERCOT, and in real-time can typically see nothing more than ERCOT's responsive reserve (PRC) levels and the status of generators connected to the transmission provider's own system. Many transmission providers indicated that they could perform better with respect to load shedding, particularly in increasing staffing and providing notice to the public, if they are able to get information about deteriorating system conditions from ERCOT earlier in the process.

Some transmission providers indicated they are already working on improvements to their public notification protocols, and believe that certain sensitive loads (including loads with back-up generation) could have benefitted from earlier notification of potential outages.

The task force also found that transmission providers with annual training programs, particularly those that require use of hands-on simulations or drills, tended to perform well during the February 2 load shedding event. Transmission providers with less frequent training, or that fail to simulate expected conditions during a load shed event, tended to have more problems with timely implementation of the required curtailment. Automated systems for shedding load may be helpful for larger transmission providers, but do not appear to be necessary

[140] One transmission provider reported that, upon receiving ERCOT's notice, it restored power to facilities believed to be compression facilities; these were later determined to be regulator stations, for which restoration of power would not affect pipeline pressure.

[141] ERCOT directed one transmission provider to restore power to five specific counties in north/central Texas due to concerns about affected gas facilities, which restoration could only be done by working outside the automated outage rotation system to identify each feeder or circuit serving those counties.

for successful implementation of a load shed program under ERCOT's current time requirements for implementation.

Price Effects of the Cold Weather Event

As discussed in the section of this report entitled "The Electric and Natural Gas Industries," ERCOT is an energy-only market. This type of market relies on scarcity pricing to provide price signals for the addition of needed resources. ERCOT transitioned from a zonal market to a nodal market in December 2010, and as part of its preparation for that transition, adopted rules in 2006 that included a Scarcity Pricing Mechanism that relaxed the then-existing system-wide cap of $1,000 per MWh. ERCOT did this by gradually increasing the cap in accordance with a defined schedule to $1,500 per MWh on March 1, 2007, to $2,250 per MWh on March 1, 2008, and finally to $3,000 per MWh on February 1, 2011, two months after the implementation of the nodal market and, as it happened, on the day before the severe weather impacts caused ERCOT to shed load.[142]

The rapidly dwindling supply of generation on February 2 created a scarcity event and, not surprisingly, caused prices to spike. By 4:55 AM, prices had reached a sustained level of $3,000 per MWh.[143]

These high prices, coupled with the fact they occurred the day after the price cap had been raised to $3,000 per MWh, fueled speculation that market manipulation may have been a factor. Such speculation was probably exacerbated by certain instances of past high prices, as well as two studies finding the existence of market power in the ERCOT markets.

In 2001, prices rose to the $1,000 per MWh cap on the first day of operation of ERCOT's pilot zonal market.[144] During the winter storm of February 2003, high prices of $990 per MWh in the balancing market and $967 per MWh in the ancillary service market were later determined to have been partially caused by "hockey stick bidding."[145] According to two studies evaluating behavior in the

[142] Potomac Report at 15.

[143] *Id*. at 20.

[144] The Steering Committee of Cities Served by Oncor and the Texas Coalition for Affordable Power, The Story of ERCOT: The Grid Operator, Power Market & Prices under Texas Electric Deregulation, at 32 (Feb. 2011), available at http//tcaptx.com/downloads/THE-STORY-OF-ERCOT.pdf.

[145] Public Utility Commission of Texas, *Report to the 79th Texas Legislature: Scope of Competition in the Electric Market in Texas*, January 2005, at 32, *available at* http://www.puc. state. tx.us/industry/electric/reports/scope/2005/2005scope_elec.pdf. Hockey stick bidding

ERCOT balancing market, large firms were found to have exercised unilateral market power between 2001 and 2003.[146] And in March of 2008, two days after the market cap rose to $2,250 per MWh, prices hit the cap for three consecutive 15-minute intervals.[147]

Given these historical events, suspicions concerning the causes of the high prices on February 2 were understandable. The Executive Director of the PUCT directed the IMM for ERCOT, Potomac Economics, Ltd., to investigate whether there was any evidence of market manipulation or market power abuse.

In its April 21 report to the PUCT, the IMM concluded there had not been any market manipulation during the cold weather event on February 2. The IMM further concluded that the ERCOT real-time and day-ahead markets operated efficiently, and that the shortage conditions were properly accompanied by scarcity level pricing, a phenomenon consistent with ERCOT's energy-only market design.[148]

The IMM reached its conclusion by examining whether there had been any economic or physical withholding. The IMM's test for economic withholding was to determine whether energy had not been produced when the capacity would have been economic, given the prevailing price. Since all available capacity was being utilized when prices spiked, the IMM concluded there had been no economic withholding.[149] The IMM's test for physical withholding was to determine whether resources were made unavailable that were actually capable of providing energy and were economic at prevailing market prices. This determination

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involves offers of a small, expendable quantity of energy or capacity well in excess of its marginal cost, which can set the marginal clearing price at times of short-term demand when all offers must be accepted. See Daniel Hurlbut, Keith Rogas, and Shmuel Oren, *Protecting the Market from "Hockey Stick" Pricing: How the Public Utility Commission of Texas is Dealing with Potential Price Gouging*, THE ELEC. J., April 2004, at 26-27.

[146] Ali Hortacsu & Steven L. Puller, *Understanding Strategic Bidding: A Case Study of the Texas Electricity Spot Market* (June 2007), http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.73.9947&rep=rep1&type=pdf; Ramteen Sioshansi & Shmuel Oren, *How Good are Supply Function Equilibrium Models: An Empirical Analysis of the ERCOT Balancing Market*, 31(1) J. REG. ECON. 1 (2007).

[147] Eric S. Schubert, Shmuel Oren & Parviz Adib, *Achieving Resource Adequacy in Texas Via an Energy-Only Electricity Market*, in ELECTRICITY RESTRUCTURING: THE TEXAS STORY 70, 92 (L. Lynne Kiesling & Andrew N. Kleit, eds., AEI Press, 2009).

[148] Potomac Report at 1-2, 8.

[149] *Id*. at 8-9.

required a review of the causes of outages and derates. After conducting this review, the IMM found no evidence that the outages and derates were caused by anything other than the physical inability of the generators to produce power.[150]

The IMM observed that the scope of the outages and derates was widespread in geography, generating unit type, and by class of market participant.[151] It also observed that those market participants that were able to operate their generation fleet at greater than 90 percent availability during the morning of February 2 were financially successful that day, and the market participants affected by significant generation outages were unprofitable.[152] Furthermore, those market participants that lost significant generating capacity and were unprofitable on February 2 did not achieve gains on February 3 that significantly exceeded the previous day's losses, despite high day-ahead prices.[153] These findings suggested to the IMM that market participants had every incentive to offer their units' capacity into the market, had they been physically able to do so.

Based both on the IMM's study and on the task force's independent evaluation of the causes of the generator outages, there does not appear to be evidence that the high prices on February 2 were the result of market manipulation. Rather, they appear to be the natural result of scarcity pricing in an energy-only market.

Rio Grande Valley Event: February 3-4

In addition to the ERCOT-wide load shed on February 2, ERCOT experienced more localized difficulties on February 3 and February 4 that necessitated local load shedding. The area affected was the southernmost tip of Texas along the Rio Grande River, designated as the Lower Rio Grande Valley (LRGV).

The weather in the LRGV is typically mild. Temperatures in February for Brownsville, the largest city in the LRGV, average a high of 72 degrees and a low of 53 degrees. For February 2011 as a whole, Brownsville had a high of 90

[150] *Id*. at 12.

[151] *Id*. at 10.

[152] *Id*. at 14.

[153] *Id.*

degrees; on February 3, however, the high reached only 36 degrees, with a low of 28 degrees.[154]

Load in the LRGV generally exceeds available local generation, making the area dependent on imports. The Rio Grande Valley import capability consists of a group of five elements, three 138 kV and two 345 kV transmission lines, owned and operated by American Electric Power (AEP), that allow for the import of energy into the LRGV area. The Rio Grande Valley import limit is a contingency import limit based on the loss of either of the two series compensated 345 kV lines that transmit electricity into the LRGV. The contingency limit is 1200 MW, with economic redispatch occurring at 1100 MW. This limit was exceeded for short periods during the evening hours of February 2, and for over 30 consecutive hours beginning on February 3 and concluding on February 4.

Two types of events can trigger load shedding to prevent an uncontrolled loss of load: under-frequency and under-voltage. Under-frequency load shedding is designed to rebalance load and generation within an electrical island following a system disturbance. Under-voltage load shedding is designed to prevent local area voltage collapse. While the ERCOT-wide February 2 event was the result of under-frequency concerns, the issue in the LRGV was one of under-voltage. Had the entities in the LRGV not implemented manual load shedding on February 3, a subsequent contingency could have resulted in the activation of automatic under-voltage load shedding.

On February 3, the LRGV area hit an all-time winter peak demand of 2734 MW.[155] A total of 829 MW of local generation was on scheduled outage that day, and the picture was further complicated by the loss of the three Frontera units, totaling 486 MW. The two Frontera combustion turbines CTG-1 and CTG-2 tripped due to frozen control equipment pneumatics at 9:47 PM and 9:59 PM, respectively, followed by the steam turbine CTG-3 at 10:00 PM. The import limit of 1200 MW had already been exceeded, beginning at 6:23 AM. When the three Frontera units tripped in rapid succession, the import level rose to 2074 MW (172.8 percent of the limit of 1200 MW). Additionally, the bus voltages at some substations dipped to 91 percent to 93 percent of nominal, which is outside the normal AEP Texas operating voltage range of 95 percent to 105 percent nominal. (The automatic under-voltage load shedding system in the LRGV activates when the voltage declines to 90 percent for three seconds.)

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[154] Weather Underground, *Almanac for Brownsville*, http://www.wunderground.com/history/airport/KBRO/2011/2/3/Daily History.html.

[155] Texas Reliability Entity, *Event Analysis: February 3-4, 2011 Lower Rio Grande Valley Load Shed Category 2f.1 Event* at 4 (April 15, 2011) (LRGV Event Analysis Report).

The transmission providers for the LRGV area are AEP, Public Utilities Board of Brownsville (BPUB), and the South Texas Electric Cooperative (STEC). AEP had previously developed a procedure with ERCOT, STEC, and BPUB that specified the load allocation for any necessary manual load shed in the event of the loss of one of the 345 kV transmission lines. The entities decided to use that plan for this event, even though it was not caused by the loss of a line but rather by the loss of Rio Grande Valley generation. AEP initiated the load shedding and the three entities each manually shed their portion of the target 300 MW load shed, beginning the process at 10:06 PM on February 3.[156] The maximum actual load shed of 459.5 MW occurred at 10:59 PM. (Power was fully restored to most customers in the early morning hours of February 4.)

Approximately 115,000 customers were affected by the rolling blackouts, with AEP contributing 60 percent of the load shed obligation and BPUB and STEC each contributing 20 percent. The task force determined that load shedding was executed well by all three entities and the required levels of load shedding were reached within ERCOT's specified 30-minute period. The entities attempted to rotate the load shed through different circuits, but due to the size of the allotments of BPUB and STEC relative to their total load, as well as the number of critical loads on their systems, the rotation periods for each circuit of load shedding were longer than desired and more frequent than during the ERCOT-wide load shed of February 2.

Some of the transmission providers in the LRGV region expressed concerns about communications with ERCOT. AEP initiated the first phase of the load shed and then requested ERCOT to notify the other transmission providers to shed their portion, as opposed to ERCOT directing the simultaneous shedding of load. As a result, AEP proceeded alone for the first phase of the load shed. The transmission providers also observed that a public announcement made by ERCOT on February 3, advising customers that further outages appeared unlikely, did not accurately reflect the situation in the LRGV and complicated the conduct of their localized load shed.

The task force concluded that in order to prevent similar problems in the future, additional generation or transmission lines are needed to reinforce the LRGV area. This is in accord with ERCOT's Regional Planning Group analysis, which concluded that there is a need for transmission or market solutions in the LRGV to meet forecasted load beyond 2014.[157] AEP Service Company has

[156] LRGV Event Analysis Report at 20.

[157] *Lower Rio Grande Valley (LRGV) 345 kV Project Analysis*, ERCOT (May 13, 2011), http://www.ercot.com/content/meetings/rpg/keydocs/2011/0513/ERCOT_Lower_Rio_Grande_Valley_345_kV_Project_Analysis.pdf.

proposed a new 345 kV transmission line from the Laredo area into the LRGV; however, improvements at this time are in the early planning stages.

February 10, 2011

In analyzing the implications of the February 2 blackouts, it is instructive to compare that day with February 10, when ERCOT did not shed either firm or interruptible load despite setting a new winter peak.[158] Cold weather was again expected on that day, and actual temperatures in the ERCOT region averaged a low of 19 degrees with a 12 degree wind chill. (This compares to a low on February 2 of 19 degrees with wind chill of 4 degrees; however, low temperatures during the earlier event were more persistent, remaining in the low twenties for four days with wind chills between 10 and 14 degrees.) The average high temperature in the ERCOT region on February 10 was over 42 degrees (compared to an average high between February 2 and February 5 that remained below freezing).

ERCOT avoided service interruptions on February 10 largely because there were far fewer forced outages. ERCOT reports that 11 units, totaling 2160 MW of generation, were forced offline at some point during the day. The biggest difference between February 2 and February 10 was the number of units forced offline on February 2 just during the early morning hours. The cumulative net outages on that morning exceeded 14,700 MW,[159] whereas for the entire day on February 10, only 2160 MW were forced offline. The equivalent total outages for the entire day of February 2 was 21,400 MW, a ten-fold difference.

The majority of the forced outages in ERCOT on February 2 were weather-related, while on February 10, few were weather-related (those few were the result of frozen valves, a frozen transmitter and automatic temperature cut-offs at some wind farms). Representative causes of forced outages on February 10 included control issues, a condensate pump that was out of service, the loss of a vacuum pump, a low head level in a cooling lake, frozen valves, low gas header pressure, and a boiler tube leak.

There appear to be three reasons ERCOT was not forced to shed load on February 10: repairs made and protective measures taken during the event of February 2 remained in place; the temperatures on February 10 were not quite as

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[158] The peak of 57,915 MW occurred at 7:15 AM.

[159] "Cumulative net outages" subtracts out those units that were successfully brought back online.

cold and the cold temperatures were of shorter duration; and the wind chill was, in the main, not as severe.

In interviews with the task force, generator operators mentioned that on or after the earlier event they had installed wind breaks, including tarps or enclosures, added portable heaters or heat lamps, repaired or added insulation, and repaired or added heat tracing. One generator changed its procedures for monitoring the reliability of its heat tracing. Some generators also continued their increased level of staffing to address freeze protection issues, and others changed elements of their control logic to prevent units from automatically tripping.

Some of the vulnerabilities identified and addressed the week before included re-routing piping or moving vulnerable equipment, correcting transformer oil levels at wind farms, and adding freeze-resistant chemicals. At least five generators kept units running, started units earlier or took other measures to keep from having a cold start. After so many static sensor and other lines froze the week before, some units left water lines draining, or took other measures to keep water flowing.

The storm on February 10 was concentrated in Oklahoma and northern Texas, unlike the more widespread storm of February 2. Temperatures by and large were somewhat less severe, especially during the day when they rose above freezing. A number of generator operators told the task force that the difference in temperatures and the shorter duration of the cold spell on February 10 were significant factors in the improved performance of their units.

Lastly, the wind chill in some areas was not as extreme on February 10 as during the preceding week. Some generator operators cited the lower wind speed as a significant factor in their improved performance, an assessment with which ERCOT concurred.[160]

Salt River Project

ERCOT was not the only entity in the Southwest that was forced to shed load during the storm of February 1 through February 5. SRP shed 300 MW of load on February 2, affecting 65,000 customers. However, only some of the generation losses leading to SRP's load shed were weather-related.

[160] Of special interest to wind units was the absence of precipitation that would ice their turbine blades. Several wind farm operators mentioned this absence as a factor in their improved performance.

SRP's problems began at 6:54 PM on February 1, when Unit 1 at the Navajo Generating Station (NGS) in Page, Arizona, tripped offline.[161] Page was experiencing colder than average temperatures, reaching a high of 36 degrees and a low of 17 degrees, and facing average wind speeds of 10 miles per hour. NGS Unit 1 tripped due to these freezing conditions when a sensing line leading to a waterwall pressure transmitter froze. The trip resulted in a loss of 330 MW of generation for the SRP balancing authority area.[162]

In response to the trip, SRP called on the SRSG for assistance and imported its allowed amount of 170 MW. It also deployed 80 MW of spinning reserves and curtailed 48 MW of interruptible load. At 8:10 PM, SRP restored the interruptible load.

To make up for the loss of NGS Unit 1, SRP's system operator scheduled Santan Generating Station (SGS) Unit 6, a 275 MW combined cycle unit (consisting of a combustion turbine and a steam turbine), to start at 5:00 AM on February 2 (it had not been included in SRP's day-ahead plan). Understanding that it might need additional generation on February 2, SRP also decided to keep SGS Unit 5, a 570 MW unit, online for the following day.

On February 2, SRP's difficulties resumed at 2:56 AM, when Coronado Generating Station (CGS) Unit 2, which is coal-fired, tripped offline due to a non-weather related mechanical problem with its coal pulverizers. Although the unit was running at only 130 MW at the time of the trip, it was scheduled for its full 389 MW output for the morning peak. The loss of CGS Unit 2 also tripped Coronado 500 kV breakers 945 and 948.

SRP lost another 75 MW at 3:20 AM, when Unit 4 at the Four Corners Power Plant (FC) tripped due to control valve problems (all 750 MW of the unit was lost, of which SRP has a ten percent share). The FC unit trip was weather-related and occasioned by frozen sensing lines. SRP dispatched SGS Units 1, 2, 5 and 6 to replace the loss of FC Unit 4 for the morning peak.

SRP was able to close the Coronado 500 kV breaker 945 at 4:21 AM, and brought Coronado 2 back online. Shortly thereafter, at 5:07 AM, SRP dispatched SGS Units 1 and 2 at 90 MW each to meet increasing system loads, and at 5:15 AM ramped SGS Unit 6 to 236 MW.

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[161] Details are based on information provided to the task force by SRP.

[162] NGS Unit 1 is a 750 MW unit that is owned by the Salt River Project, U.S. Bureau of Reclamation, Los Angeles Department of Power & Light, Arizona Public Service, NV Energy, Inc., and Tucson Electric Power. SRP has a 21.7 percent ownership in the unit. NGS Unit 2, discussed below, has the same ownership structure and total output.

At 5:18 AM, SRP dispatched duct firing on SGS Units 5&6.[163] A few minutes later, at 5:22 AM, the SGS Unit 6 steam turbine tripped, although the unit's combustion turbine was able to continue supplying generation. The steam unit had an output of 80 MW. At this time, SRP system operators told the generator operators at SGS that they needed the steam turbine back online as quickly as possible. The system operators were not aware, and were not advised by the generator operators, that in order to get the steam turbine back online, the combustion turbine would have to be ramped down significantly. Between 5:22 AM and 5:44 AM, as a result of the ramping down of the combustion turbine, the output of SGS Unit 6 was reduced from 159 MW to 15 MW.

SRP experienced a flurry of activity between 5:22 AM and 6:00 AM. After the loss of the SGS Unit 6 steam turbine, SRP dispatched the Mormon Flat Hydro (MFH) Unit 2 to come online at 50 MW, interrupted 38 MW of instantaneous interruptible load, and at 5:30 AM dispatched Horse Mesa Hydro (HMH) Units 1, 2 and 3, for a total of 30 MW additional generation. SRP's system operators also directed its merchant group to purchase 100 MW for the 7:00-8:00 AM hour. At 5:31 AM, SRP called on MFH Unit 1 for 10 MW, and also requested that a large interruptible customer drop 100 MW of 10-minute interruptible load. At this point SRP's reserves were diminishing, and SRP used the interruptible load to increase its spinning reserves.

At 5:39 AM, SRP was able to bring SGS Unit 2 online at 92 MW, and at 5:40 AM, SRP's merchant group called on another interruptible customer to drop 29 MW of contracted interruptible load in the 6:00-7:00 AM hour. However, Tucson Electric Power contacted SRP at the same time to report that it had lost Springerville Unit 3, which diminished SRP's available capacity by another 25 MW. At 5:44 AM, SRP determined that SGS Unit 6 would not be able to return to service, resulting in a total loss of 236 MW of capacity.

SRP was able to bring on SGS Unit 2 online at 40 MW at 5:45 AM, and SGS Unit 1 at 40 MW at 5:57 AM. At 6:00 AM on February 2, SRP system load was running at 3557 MW, which was 161 MW higher than its day-ahead schedule.

At 6:02 AM, SRP dispatched Units 4, 5, and 6 at the Agua Fria Generating Station (AFGS), at approximately 70 MW each, to recover reserves and meet forecasted load. SGS Unit 2 also reached full load of 100 MW at this time. Two minutes later SRP dispatched Kyrene Generating Station (KGS) Units 5 and 6, at 60 MW each. Unit 6 was brought online at 6:11 AM and Unit 5 at 6:14 AM. SRP

[163] Duct firing is a process involving additional burners being fired for a heat recovery steam generator (HRSG) to increase steam production and output. The output of the burners combines with the hot exhaust gas from the gas-fired turbines to create steam.

dispatched the 41 MW KGS Unit 4 at 6:08 AM and HMH Units 1, 2 & 3 at 10 MW each at 6:09 AM. At this point all available SRP generating units were dispatched, and SRP purchased an additional 100 MW to begin at 6:20 AM.

SRP issued a Capacity Alert at 6:17 AM. (A Capacity Alert is an internal alert telling operators in the balancing authority that SRP believes that if another unit were to trip, the balancing authority would have trouble recovering.) A Capacity Alert is a precursor to a NERC EEA-1.

Five minutes later, NGS Unit 2 tripped due to frozen waterwall pressure sensing lines. The trip resulted in the loss of 350 MW for the SRP balancing authority area, and constituted the event that triggered load shedding. In response to the NGS Unit 2 trip, SRP again called on SRSG for assistance and was supplied with 128 MW, 82 MW less than anticipated. EPE, a neighboring balancing authority experiencing its own difficulties, told SRP that it could not deliver the assistance it was obligated to provide under the SRSG Agreement.

Immediately after the NGS Unit 2 tripped at 6:22 AM, SRP's system operator determined, based on the information available to him, that the remaining reserve and emergency assistance was insufficient to recover SRP's ACE in a timely manner.[164] The operator concluded that 300 MW of firm load needed to be shed to insure stable operations of the bulk electric system should additional generation trip offline. The system operator contacted its reliability coordinator, WECC's LRCC (Loveland Reliability Coordination Center), to notify it of the impending load shed. At 6:24 AM LRCC directed SRP (as transmission provider) to shed 300 MW. At the same time, KGS Units 5 and 6 reached full load of 62 MW each, and SRP's merchant group purchased 190 MW for the 7:00-8:00 hour.

At 6:29 AM, SRP called on the last of its 10-minute interruptible load, curtailing 136 MW. At the same time, SRP's distribution service provider initiated its rotating load shed program. Once initiated, load shed is to take place within one minute; however, SRP's distribution service provider encountered problems, requiring five full minutes to initiate the sequence. At 6:31 AM, LRCC declared an EEA 3 for SRP, which was seven minutes after SRP had initiated the shedding of 300 MW of load.

SRP reports that the 300 MW load shed event affected approximately 65,000 customers.

[164] ACE, or area control error, refers to the instantaneous difference between a balancing authority's net actual and scheduled interchange with other balancing authorities, taking into account the effects of frequency bias and correction for meter error.

Immediately after the load shed was initiated, SRP's ACE returned to normal. At this time SRP also restored its reserves to meet its SRSG reserve requirement. At 6:34 AM, Springerville Unit 3 tripped offline due to high furnace pressure, cutting 75 MW of generation (although this did not affect SRP's operations).

AFGS Units 4, 5 and 6 remained online and ramping to full load, and at 6:34 AM SRP's system operator instructed the distribution service provider to restore 100 MW of firm load. However, instead of restoring only the 100 MW, the distribution service provider mistakenly restored all 300 MW of the load that was shed. At 6:45 AM, the distribution service provider realized its mistake and, without further instruction, shed 200 MW of the load that had been restored. Prior to the second load shed of 200 MW, SRP's ACE had returned to normal.

At 6:52 AM, KGS Unit 4 came online and began ramping to full load, and the system operator directed the restoration of another 100 MW of shed load. At 6:55 AM, SGS Unit 6 returned to service and a minute later the system operator directed that the final 100 MW of shed load be restored. By 6:57 AM, approximately a half-hour after the initial load shed, SRP was able to restore service to its customers.[165] At 7:05 AM, LRCC declared a return to an EEA 0 condition effective as of 6:59 AM.

El Paso Electric Company

During the cold weather event, EPE experienced forced outages of all but one generator in its El Paso area fleet. Because of the significant loss of its local generation (six out of seven operational units) and the resulting loss of dynamic reactive support, EPE was limited in the amount of generation that could be imported on its transmission system.[166]

With limited import capability and limited local generation, EPE had to operate its system in such a way as to prevent cascading due to voltage instability. It was therefore necessary for EPE to reduce loads in its service area by manual load reduction. Load shedding occurred four times between February 1 and

[165] Although SRP had directed that all load be restored at this time, some of the distribution service provider's breakers would not close, leaving 4000 customers without service until 9:43 AM.

[166] EPE utilizes WECC Path 47 to import power from Palo Verde and Four Corners. The capability of this path is limited by post-contingency voltages. EPE can also utilize the Eddy DC tie in New Mexico to help regulate the flows on Path 47 by importing up to approximately 200 MWs from Southwestern Public Service (SPS) to the East.

February 4, totaling up to approximately 1023 MW and affecting 253,000 customers. Two of the load shed events occurred on February 2, one on February 3 and one on February 4 (all due to voltage instability concerns).

The four-day sequence of events is set forth below.[167]

Tuesday, February 1, 2011

On February 1, an arctic air mass moved in across the Las Cruces and El Paso area. Temperatures hovered in the low 40s between midnight and 4:00 AM, but dropped as the wind changed direction. The temperature dipped below freezing at approximately 8:51 AM and then plummeted into the middle teens by the late evening hours. Maximum temperature for the day was 43 degrees and the minimum was 14 degrees.

As the colder air moved in, gusty winds picked up in the late evening, measuring up to 26 mph at the El Paso International Airport. These gusts, combined with air temperatures in the middle teens, produced wind chill values below zero. The peak wind gust reached on February 1 was 43 mph (during the 1:00 AM hour).

Timeline of Events

- At 6:34 PM, the Coyote-Dell City 115 kV line tripped (reportedly as a result of gunshot damage to a conductor).
- At 8:07 PM, the first of EPE's gas-fired generators, Newman No. 3, tripped (loss of 40 MW).[168]
- At 10:15 PM, Rio Grande No. 6 tripped (loss of 50 MW).
- At 10:15 PM, system controllers contacted LRCC, EPE's reliability coordinator, and advised it of the loss of local generation.
- At 10:52 PM, system controllers requested that interruptible loads be interrupted due to the extreme weather conditions and the loss of local generation.

[167] Details are based on information provided to the task force by EPE.

[168] The various causes of EPE's unit trips are discussed in the following section of the report, entitled "Causes of the Outages and Supply Disruptions."

- At 11:45 PM, the Copper Generator was brought online.

Wednesday, February 2, 2011

The air temperature continued to drop during the morning of February 2, falling from 13 degrees at 1:00 AM to 8 degrees by 8:00 AM. Temperatures moderated during the afternoon, reaching 15 degrees. On February 2, the maximum temperature was 15 degrees (45 degrees below normal) and the minimum temperature was 6 degrees.

The maximum temperature for the day was the coldest maximum (high) temperature ever recorded in El Paso, Texas. A few wind gusts up to 24-26 mph occurred around mid-day. This, combined with the frigid air temperatures, produced wind chill values of -9 to -10 degrees. The peak wind speed reached on February 2 was 26 mph.

Timeline of Events

- At 12:10 AM, Newman 5 GT3 tripped.
- At 12:26 AM, Newman 5 GT4 tripped.
- At 1:49 AM, Rio Grande No. 8 tripped.
- At 1:53 AM, system controllers contacted LRCC, which declared an EEA l.
- At 2:02 AM, EPE purchased power from SPS; the Eddy DC tie was opened and ramped to 100 MW.
- At 2:27 AM, a switching order was given by the system controller to synchronize PNM's Luna Energy Facility (Luna) to the grid, permitting the transmittal of power EPE had purchased from PNM.
- At 3:17 AM, Newman Generator No. 4 GT1 tripped.
- At 3:20 AM, Four Corners Unit No. 4 tripped.

- At 5:07 AM, the HVDC terminal at the Eddy DC Tie experienced a runback[169] from 100 MW to 48 MW.

- At 5:12 AM, system controllers again contacted LRCC, and the EEA level was heightened to EEA 2. This Alert advised other utilities that EPE was placing its load management procedures in effect due to its energy deficient condition. Actions taken pursuant to this Alert included public appeals to reduce demand, made through media announcements, and other demand-side management procedures.

- At 6:28 AM, the Coyote-Dell City 115 kV line was restored.

- At 7:12 AM, the Newman No. 4 steam turbine (ST) tripped, and the Newman-Butterfield 115 kV line opened at Newman (tripping the line).

- At 7:16 AM, the Newman No.4 GT2 unit tripped. With the loss of Newman No.4 GT2, the Copper unit was the only local unit remaining online that could supply dynamic reactive support (it was producing 55 MW of power).

- At 7:22 AM, system controllers initiated load shedding in order to balance load with generation and maintain voltage stability. Area load was at 982 MW at the time, and approximately 170 MW of firm load was shed.

- At 7:23 AM, EPE again contacted LRCC and EPE's EEA status was increased to an EEA 3. This alert advised other utilities that EPE had implemented firm load interruptions.

- At 7:55 AM, system controllers saw that Luna had lost approximately 130 MW of generation. Another 103 MW of load was shed, with load stabilizing at 710 MW.

- At 8:16 AM, Luna ramped up to 235 MW.

- At 9:51 AM, the combustion turbine portion of PNM's Afton combined cycle generator was placed online (the steam turbine portion of this generator experienced problems and remained unavailable throughout the

[169] "Runback" is a manually or automatically controlled decrease in output designed to protect against loss of thermal transfer capability or transient angle instability.

event). EPE made arrangements to obtain power from that unit on an hourly basis.

- At 12:17 PM, controlled load shedding ended, with load at 977 MW.
- At 12:19 PM, LRCC was contacted and EPE's EEA alert level was decreased to EEA 2.
- At 6:04 PM, the terminal at the Eddy DC tie tripped (opening the Amrad-Eddy 345 kV line).
- At 6:11 PM, load shedding resumed, and continued for approximately two hours and 45 minutes. Load shed amounts varied between 100 and 250 MW during this period.
- At 6:15 PM, EPE contacted LRCC, which again placed EPE under EEA 3 status.
- At 8:58 PM, load shedding terminated because of reduced load demand. EPE contacted LRCC, which changed the EEA alert level back to an EEA 2.
- At 11:04 PM, the Eddy DC tie (and the Amrad-Eddy 345 kV line) resumed operation. (According to SPS, operating agent for the DC Terminal, the tie had tripped due to loss of thyristors.[170])

Thursday, February 3, 2011

The lowest temperatures of the event were experienced in the El Paso area during the morning of February 3, 2011. Temperatures remained in the single digits from midnight through 10:00 AM, slowly climbed into the teens during the late morning, and reached a maximum of 18 degrees at 2:51 PM. The high temperature for the day was 18 degrees, and the low was 1 degree. (The high temperature was 43 degrees below normal, and the low was 34 degrees below normal). The peak wind speed reached on February 3 was 20 mph. The combination of frigid air temperatures and wind speeds produced wind chill values from midnight to 11:00 AM of -10 to -17 degrees.

[170] A thyristor is a semiconductor with an anode, a cathode and a gate. Thyristors have the ability to switch high voltages and withstand reverse voltages, and are used in switching applications, especially in AC circuits, for AC power control, and overvoltage protection for power supplies.

Timeline of Events

- At 3:45 PM, PNM's Afton CT tripped.
- At 4:23 PM, PNM put the Afton CT back online.
- At 5:00 PM, as the evening load increased, LRCC was contacted, and EPE's alert status was elevated to EEA 3.
- At 5:30 PM, controlled rotating load shedding resumed for just over five hours. During this period, the load shed amounts varied between 100 MW and 250 MW.
- At 6:52 PM, Newman 4 GT1 was brought online.
- At 7:20 PM, Newman 4 GT1 tripped.
- At 9:32 PM, Newman 4 GT1 returned online.
- At 10:30 PM, Newman 4 GT2 was brought online.
- At 10:30 PM, EPE terminated the controlled rotating load shedding.
- At 10:40 PM, LRCC lowered the EEA level to Alert Level 2.

Friday, February 4, 2011

On February 4, although skies were clear and winds relatively calm, temperatures were as low as 3 degrees during the early morning hours. By late morning, temperatures moderated, reaching the middle 20s by 12:00 PM. The temperature continued to rise during the afternoon, and the high for the day was 37 degrees. Winds, with speeds under 10 mph, were generally light and variable in direction. The low for the day was 3 degrees. (The maximum air temperature was 24 degrees below normal and the minimum air temperature was 32 degrees below normal).

Timeline of Events

- At 2:02 AM, Newman 4 GT2 tripped.
- At 2:04 AM, Newman 4 GT1 tripped.

- At 3:17 AM, PNM's Luna steam turbine tripped.
- At 3:23 AM, one Luna gas turbine dropped from 90 MW to 11 MW.
- At 3:51 AM, the Luna steam turbine was brought back online and slowly ramped up.
- At 6:30 AM, LRCC issued an EEA Level 3 for EPE. With Copper again as the only local unit online, controlled rotating load shedding of between 100 MW and 250 MW resumed.
- At 6:49 AM, Newman 4 GT2 was brought online.
- At 12:05 PM, the controlled rotating load shedding ended.
- At 12:12 PM, the RC changed EPE's alert status to an EEA Level 2.
- At 3:57 PM, Newman 5 GT4 unit was brought online and remained stable at 50 MW.
- At 5:12 PM, the Rio Grande 8 unit was brought online.

Due to the added generation, which provided the necessary dynamic reactive support, no controlled rotating load shedding was required for the Friday night peak load period or thereafter during the event.

Saturday, February 5, 2011

- At 4:07 PM, Newman 5 GT3 came online.
- At 4:30 PM, LRCC modified EPE's alert status to an EEA Level 1.

Sunday, February 6, 2011

- At 9:46 AM, LRCC decreased EPE's alert status to an EEA Level 0.

Public Service Company of New Mexico

PNM set a new record winter system demand during the February cold weather event and experienced outages on some of the generating units it owns,

co-owns, or from which it purchases power.[171] PNM was generally able to meet its system load requirements and also to provide energy assistance to another utility. On February 3, however, PNM was forced to implement a localized rolling blackout in the Alamagordo and Ruidoso areas in southern New Mexico, and experienced an outage in the town of Clayton in northeastern New Mexico.

In the Alamogordo and Ruidoso areas, the February 3 rolling blackout was implemented at 5:21 AM by the PNM Distribution Operations Center, as a result of a transmission line outage. The PNM Amrad to Alamogordo 115 kV transmission line locked out due to a failed conductor clamp, a condition that was apparently unrelated to the weather. As a result, the Las Cruces to Alamogordo 115 kV transmission line, owned by Tri-State Generation and Transmission Association, Inc. (Tri-State), became overloaded and required load relief from PNM and Tri-State. PNM implemented its share of the load curtailment by sequential curtailment of two separate feeder lines. Approximately 20,207 customers were affected, with an estimated load loss of up to 22.1 MW. All circuits were fully restored at 8:08 AM.

The outage in Clayton began at 5:03 AM as a result of the outage of a Tri-State 69 kV transmission line that serves PNM's Van Buren substation, located in Clayton. A static wire, stretched by the extremely cold weather, snapped and fell on one of the phases of the line, interrupting service to the town. All service was restored at 6:54 AM. The estimated load lost was 3.7 MW.

Southwest Power Pool

SPP also experienced severe weather conditions over much of its footprint during the February cold weather event. However, none of its entities was forced to shed load. Three BAs within SPP declared varying levels of EEAs due to tripping or derating of generating resources or deficiencies in natural gas supply. In one instance, SPS requested an EEA 1 following the trip of a 250 MW gas-fired generating unit. SPS had all of its available resources in use and issued public appeals for energy conservation. In a second instance, Oklahoma Gas & Electric Company (OG&E) experienced multiple generation losses on February 2 and February 3, and requested four separate EEA 2 declarations during the week. It was unable to meet its energy commitments to the reserve sharing group run by SPP. In the last instance, Sunflower Electric Cooperative (Sunflower) requested an EEA 3 on February 2 following the loss and subsequent derating of a large coal

[171] Generating units affected, to a greater or lesser degree, included Four Corners Unit 4, Reeves Unit 1, Reeves Unit 3, Delta Person CT, Valencia, Afton, LGS Units 1 and 2, and Luna Unit 2.

generating unit. The failure to start of a gas-fired combustion turbine aggravated the situation, which continued until the afternoon of February 3. During this period, Sunflower was unable to meet its energy commitments to the SPP reserve sharing group. However, following declaration of the EEA 3, Sunflower obtained sufficient transmission service to purchase energy and was able to meet its own firm energy commitments, thereby avoiding the need to shed load.

In SPS's case, its purchases over the Blackwater Tie (a connection between the Western and Eastern Interconnections) were lost between 9:00 AM and 10:00 AM on February 2, due to capacity emergencies in the Western Interconnection. SPS replaced this purchase with a 100 MW purchase from Public Service Company of Colorado, importing it over the Lamar Tie (another one of the connections between the Western and Eastern Interconnections). SPS ultimately increased this purchase to 210 MW, and was later also able to make limited purchases through the Blackwater Tie.

Notwithstanding SPS's transactions over the ties, the majority of the purchases made by the energy-deficient utilities within SPP were made from other SPP entities. Thus, even if SPP had been separated from its neighbors by asynchronous ties, as is ERCOT, it probably would not have had to shed load during the February event. This suggests that the problems ERCOT experienced did not directly relate to its functionally separate interconnection status, but rather to the ability and preparedness of the generators within its footprint to operate as scheduled during the severe weather conditions.

B. Natural Gas

The extreme cold experienced in early February 2011, particularly on February 2 and February 3, caused widespread production declines. These reductions were typically the result of freeze-offs,[172] mostly at wellheads but also in nearby processing plants. To a lesser extent, other equipment reliability issues contributed to the problems, both at the wellhead and at processing and treating facilities. The rolling power blackouts in ERCOT also played a role in the Fort Worth Basin, as did customer curtailments in the Permian Basin. These supply reductions had adverse effects all the way down the delivery chain.[173]

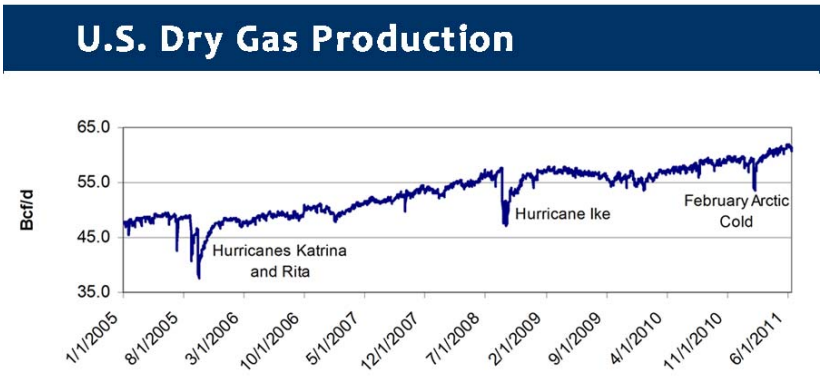
[172] A "freeze-off," as described earlier, occurs when water produced alongside the natural gas crystallizes or freezes, completely blocking off the flow and shutting down the well.

[173] Unless otherwise noted, the entity-specific data was obtained from materials submitted to the task force by producers, processing plants, pipelines, and LDCs.

This subsection summarizes the supply shortfalls resulting from production declines in the basins, discusses the resulting reduced gas volumes and pressures experienced by the pipelines, and ends with a detailed examination of the retail curtailments made by LDCs in the affected states of New Mexico, Arizona, Texas, and California.

Producing and Processing Facilities

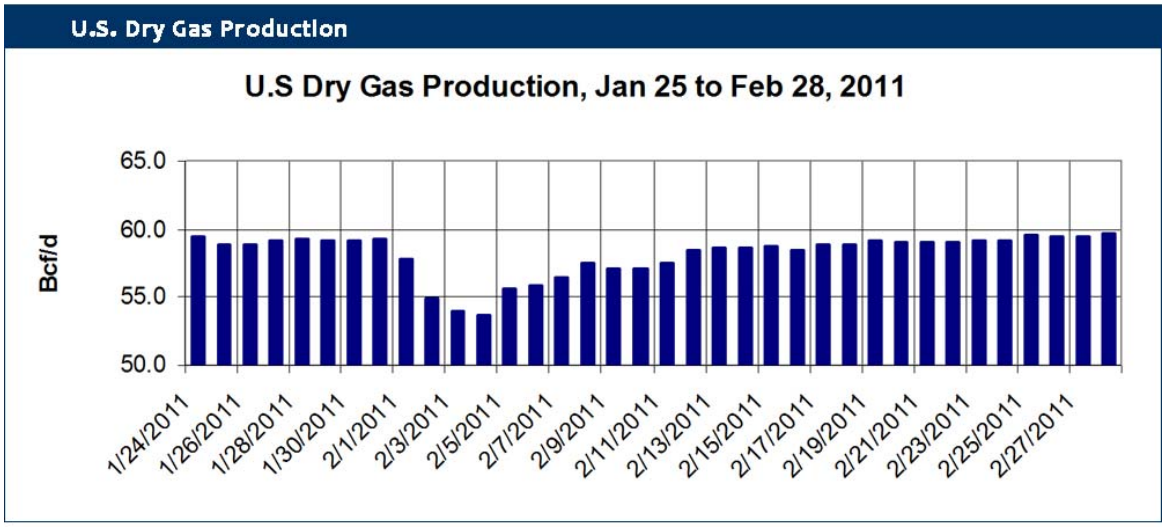
The reductions in supply experienced during the cold weather event were comparable in magnitude to production shut-ins during hurricanes. The following chart illustrates this point.



Source: Task Force chart based on Bentek data

Relative to average dry gas production of 59.22 Bcf per day on January 31, 2011, Bentek estimates that production in the first week of February declined by 5.55 Bcf per day, a reduction of 9.4 percent. The decline began on February 1 and reached its lowest level on February 4.[174]

[174] Data is based on task force analyses using supply and demand history from Bentek.



Source: Task Force chart based on Bentek data

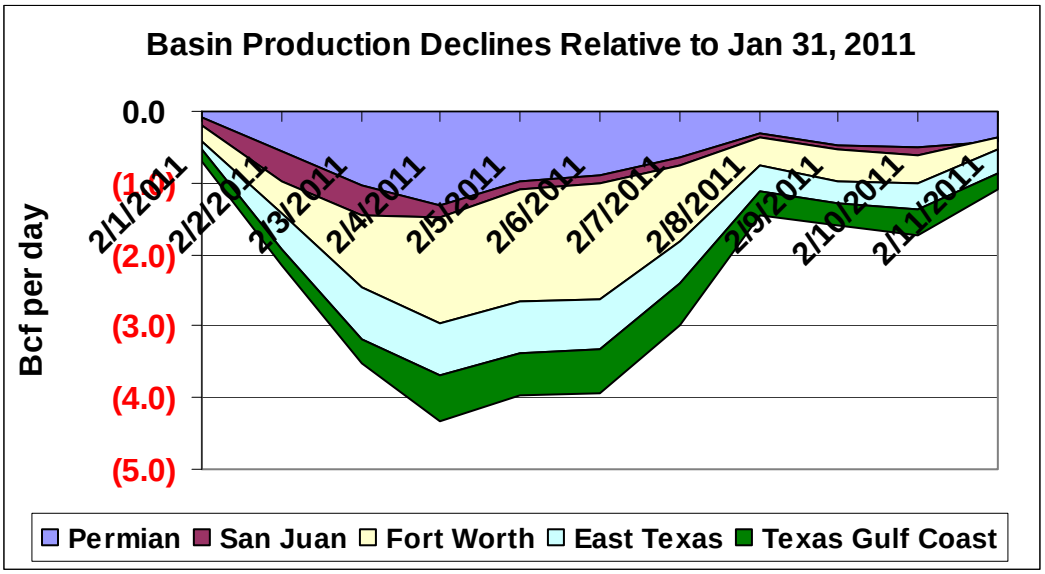
Of the 5.55 Bcf per day decline during the first week in February, 79 percent, or 4.36 Bcf per day, occurred in production basins in Texas and New Mexico (where production declined by 21 percent). Both the San Juan Basin in northern New Mexico and the Permian Basin in west Texas and southeastern New Mexico tend to experience production declines with low temperatures, and the February event was no exception. The declines in these basins, together with the large increases in demand, were almost exclusively responsible for the gas curtailments in Texas, New Mexico and Arizona.[175]

This weather event was so extreme that production freeze-offs were experienced not only in the San Juan and Permian Basins, but throughout Texas and as far south as the Gulf Coast. Based on scheduled pipeline receipts, the task force estimates that production in the Fort Worth Basin declined by 1.63 Bcf per day compared to the last week of January, 2011; East Texas Basin production declined by 0.72 Bcf per day; and Gulf Coast Basin production declined by 0.65 Bcf per day. [176] The shortfalls in these additional Texas basins, while not directly a cause of the natural gas curtailments, did contribute to fuel-related electric

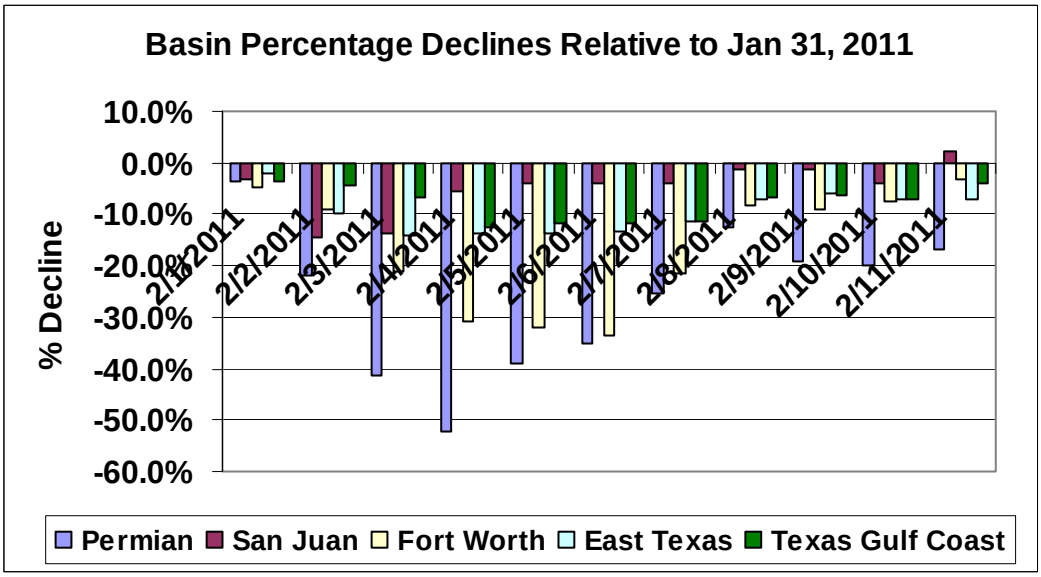
[175] Production declined by 0.43 Bcf per day in the San Juan Basin and by 1.31 Bcf in the Permian Basin, based on task force analyses of Bentek supporting data, pipeline receipts and flow data from El Paso and Transwestern.

[176] Staff's analysis based on supporting data, display reports and data warehouse on file with Bentek (unpublished); s*ee also Market Alert: Deep Freeze Disrupts U.S. Gas, Power, Processing*, Bentek Energy LLC, Feb. 8, 2011, at 2-6; materials submitted to the task force by pipelines. Note that basin level production reductions may not be equal to the total February 4 reduction as not all basin level maximum reductions occurred on February 4.

generation failures in ERCOT. The following charts demonstrate absolute and percentage declines by production basin.



Source: Task Force chart based on Bentek data



Source: Task Force chart based on Bentek data

The causes of these production declines are examined in detail in the following section of this report, entitled "Causes of the Outages and Supply Disruptions."

Effects on the Pipelines and Storage Facilities

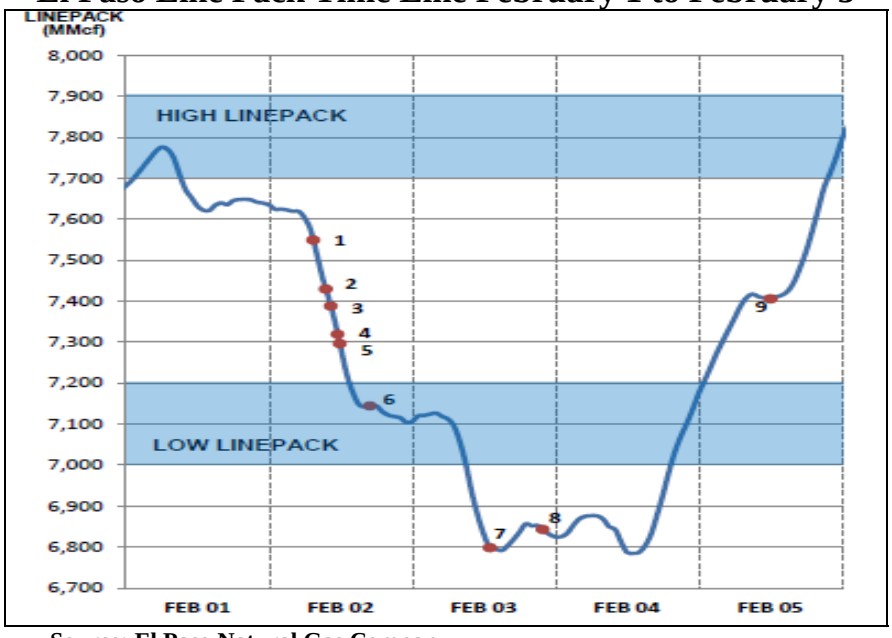
At the same time that gas supplies flowing into the pipelines were reduced, shippers requested increased volumes of gas. The reduced supply relative to higher deliveries (a situation known as a draft condition) resulted in lower line pressures and reduced line pack, which for most pipelines began on February 2.[177]

Between February 1 and February 4, pipelines responded to this draft condition through a variety of approaches. To the extent possible, deliveries to shippers were met by relying upon line pack. Pipelines with storage used increased withdrawals to build line pack. El Paso, for instance, used its Washington Ranch Storage Field to support its south system when gas supplies failed to arrive.

El Paso

The effect of the draft conditions on El Paso's line pack is depicted in the following graph (the numbered dots reference various occurrences on El Paso's system during the cold weather event):

El Paso Line Pack Time Line February 1 to February 5



Source: El Paso Natural Gas Company

[177] Generally by February 4, line pressures and line pack began rising again, as the previous day's scheduled receipts were received into the system. By February 5, line pack grew to a level above that prevailing on February 1.

El Paso system demand increased from 3,416 MDth[178] on January 31 to 3,675 MDth on February 2. For the same period, supply from all sources, including pipeline interconnects, decreased from 3,264 MDth to 3,040 MDth. As supply decreased and demand increased, El Paso used line pack to attempt to maintain deliveries. As a result, line pack fell from almost 7.8 Bcf on February 1 to approximately 6.8 Bcf at 2:00 PM on February 3.

As line pack fell, pipeline pressure on the western edge of the system dropped below 600 pounds per square inch gauge (psig). Pressure on the east side of the system had already dropped below 600 psig, as of 12:00 noon on the previous day. At 10:51 PM on February 3, El Paso issued a low pressure force majeure announcement, suspending its contract obligations and declaring that operating pressure on portions of its system could not sustain contract levels.

Pipeline Communications

Interstate pipelines issue a variety of communications and directives to shippers and, pursuant to FERC regulations (18 CFR §284.12 (2011)), post critical notices to describe strained operating conditions, to issue operational flow orders and, when applicable, to make force majeure announcements. Most intrastate pipelines provide similar information and instructions to shippers, either by posting or direct communications.

Critical notices describe situations when the integrity of the pipeline system is threatened. A critical notice will specify the reasons for and conditions making issuance necessary, and also state any actions required of shippers. Operational integrity may be determined by use of criteria such as the weather forecast for the market area and field area; system conditions consisting of line pack, overall projected pressures at monitored locations, and storage field conditions; facility status (defined as horsepower utilization) and availability; and projected throughput versus availability, for capacity and supply.

Operational flow orders (OFO) are used to control operating conditions that threaten the integrity of a pipeline system. (Individual pipeline companies may have other names for operational flow orders such as alert days, performance cut notices or an emergency strained operating condition.) OFOs request that shippers balance their supply with their usage on a daily basis within a specified tolerance band. An OFO can be system-wide or apply to selected points. Failure by a shipper to comply with an OFO may lead to penalties. Pipelines may also

(cont'd)

[178] "MDth" is a thousand dekatherms.

limit services such as parking and lending of natural gas, no-notice (the provision of natural gas service without prior notice to the pipeline), interruptible storage and excess storage withdrawals and injections.

Force majeure, if authorized by the pipeline's tariff, is a declaration of the suspension of obligations because of unplanned or unanticipated events or circumstances not within the control of the party claiming suspension, and which the party could not have avoided through the exercise of reasonable diligence.

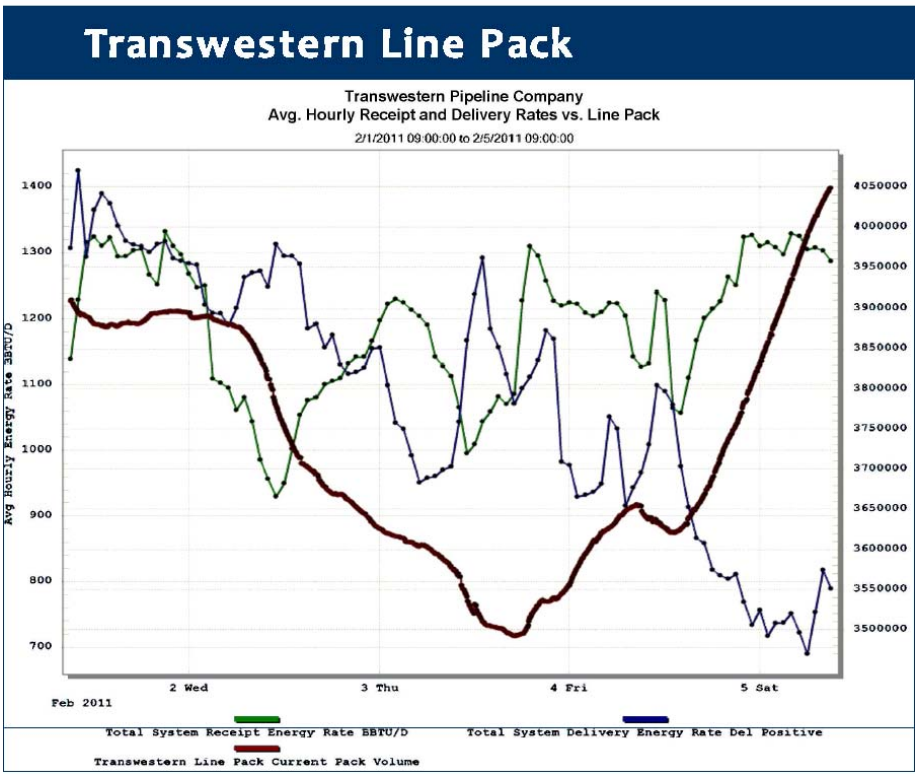
Based on data responses to task force inquiries, the number of companies making use of these various communications and directives for weather-related reasons in the Southwest during the first week of February is as follows:

Type of Pipeline	Number of Data Responses	Number of Companies With a Critical Notice	Number of Companies With an OFO	Number of Companies Declaring Force Majeure
Interstate	24	6	3	1
Intrastate	21	5	5	3

El Paso Natural Gas issued a force majeure declaration on February 3, stating that it had experienced system operating pressure on portions of its mainline and some laterals that could not sustain contract levels. The other interstate pipeline most affected by the supply shortfalls, Transwestern, did not declare a low pressure force majeure.

Transwestern

The effect of the draft conditions on Transwestern's line pack is depicted in the following graph.



Source: Transwestern Pipeline Company, LLC

Scheduled deliveries on Transwestern from January 31 to February 2 increased from 1,426 MDth to 1,526 MDth. Supplies dropped by approximately 400 MDth by midday on February 2; however, Transwestern continued to make scheduled deliveries from line pack. Accordingly, line pack decreased from 3.9 Bcf on February 1 to a low of 3.5 Bcf on February 3. Transwestern, unlike El Paso, did not declare a low pressure force majeure.[179]

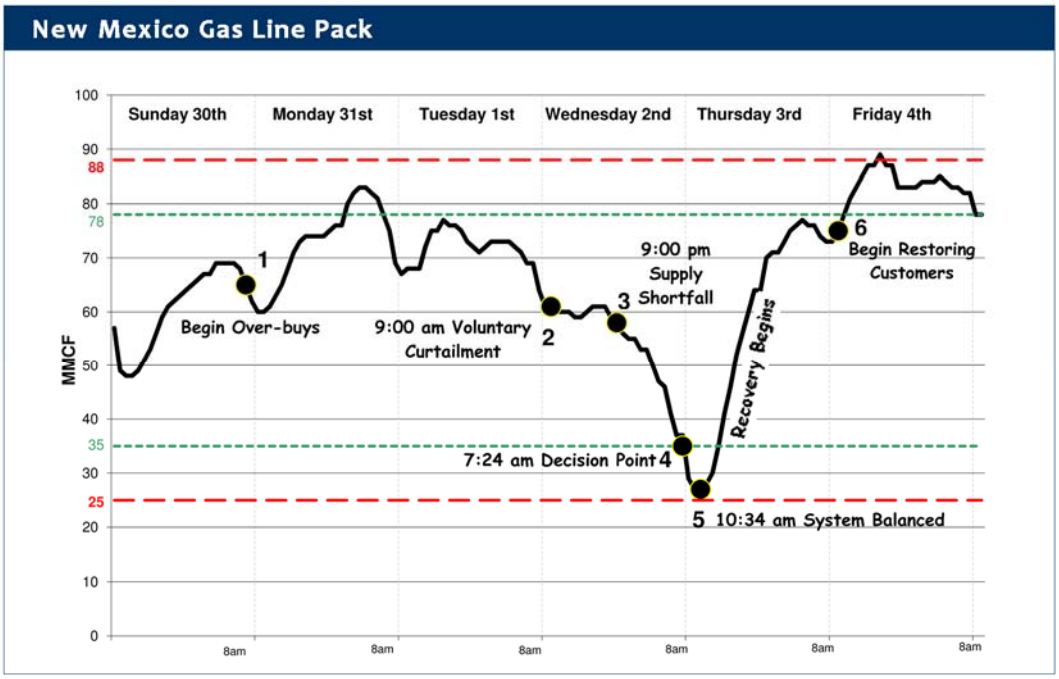
New Mexico Gas Company

NMGC also experienced significant line pack problems on its distribution system. On January 31, NMGC bought additional supply for its north segment and its south/remotes segment, for delivery on the following day. On February 2,

[179] By midday on February 3, pressures and line pack were beginning to increase, and on February 4, NMGC's line pack was over 4 Bcf.

NMGC contacted 39 large industrial and commercial customers, requesting them to reduce or curtail their gas usage. By 9:00 PM on February 2, NMGC reported to supplying pipelines that pre-ordered gas was not being delivered as scheduled.

The effect of events on NMGC's line pack is depicted in the following graph.



Source: New Mexico Gas Company

The vast majority of the shortages experienced on NMGC's north segment on February 2 and 3 was attributable to supply failures at the Transwestern Rio Puerco and El Paso's Wingate interconnection points. An NMGC representative has stated that the failure of Transwestern to deliver scheduled flows of 127,454 MMBtu on February 2 and 146,438 MMBtu on February 3 "was devastating to NMGC and its customers."[180]

Transwestern responded by observing that it scheduled much greater volumes of gas at Rio Puerco than NMGC historically flowed (and equal to the amount nominated by NMGC and other shippers to the point). NMGC was unable to flow all of the scheduled volumes, suggesting there were difficulties on NMGC's system in taking away the gas from the Rio Puerco delivery point. On February 2,

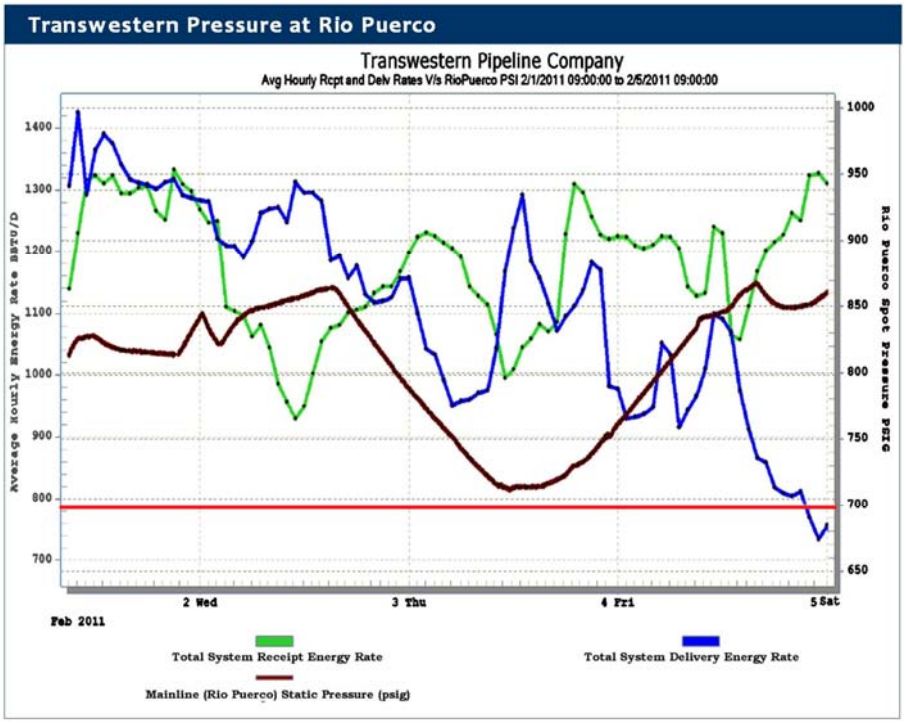
[180] Transcript of Testimony of Tommy Sanders at 13, In the Matter of an Investigation into New Mexico Gas Co.'s Curtailments of Gas Deliveries to New Mexico Consumers, NMPRC (Mar. 17, 2011) (No. 11-0039-UT).

for example, Transwestern scheduled 305,000 MMBtu/d and NMGC took 182,000; on Feb. 3 Transwestern scheduled delivery of 298,000 MMBtu/d at Rio Puerco, and NMGC took 128,000.

NMGC also reported lower pipeline pressure than those on which it typically relies. On an average winter day in the north segment, pressure ranges from 800 to 900 pounds per square inch atmosphere (psia) at Rio Puerco. The average pressures were lower during the week of January 31 and, from February 1 to February 4, the loss of pressure caused NMGC to experience significant pressure losses on its own system. For example, the interstate pipeline pressure at NMGC's interconnection at Rio Puerco fell to a low of 724 psia from a normal operating pressure of 850 psia.

Notwithstanding this decline in pressure, Transwestern's contractual obligation with respect to pressures at Rio Puerco (as opposed to its typical operating pressures) is 700 psia, and Transwestern reports that pressure never fell below that obligation.

The following chart provided by Transwestern depicts the pressure at Rio Puerco (fluctuating brown line) relative to contractually obligated pressure (non-fluctuating red line), total receipts (green line) and deliveries (blue line) on the Transwestern system. According to the chart, pressure did not fall below the contractual obligation of 700 psia.



Source: Transwestern Pipeline Company, LLC

Coordination Among Pipelines to Address Supply Problems

Flows between and among pipelines through redirected supplies and incremental transactions at least partially alleviated supply shortage conditions during the first week of February, 2011. These flows were the result of active coordination among the involved counterparties to address shortfalls. The redirection of gas came too late to avoid the curtailments in New Mexico and Arizona that occurred on February 2 and February 3. However, in the Texas intrastate markets, the increased purchases of gas at pipeline interconnects was an important factor in maintaining pressure in the Dallas-Fort Worth area and also served to move gas east to west in response to reduced supply at Waha.

Changes in gas deliveries do not occur instantly. Operation Balancing Agreements (OBA) contractually specify how gas imbalances between flows and scheduled amounts are to be managed. (Interstate pipelines are obligated by FERC regulations to have OBAs at interconnects with other interstate pipelines and with intrastate pipelines). These agreements enabled counterparties to make operational changes and revise nominations.

Chevron Keystone Storage Facility

In addition to the pipelines, at least one storage facility experienced weather-related difficulties. These difficulties, however, stemmed not from freeze-offs upstream, but from the rolling blackouts on ERCOT's system and from the facility's own operational problems.

The Chevron Keystone Storage Facility (Keystone), which has interconnections with El Paso, Transwestern, and Northern Natural Gas Company, was affected by two rolling blackouts on February 2, at 6:30 AM and 10:00 AM. It was shut down completely for six hours (from 6:30 AM to 9:30 AM and again from 10:00 AM to 1:00 PM).

Keystone remained at less than 100 percent capacity through February 6, due to line and equipment freeze-offs. Keystone declared force majeure at 9:00 AM on February 2. As a result, during the period February 2 through February 4, Keystone was unable to deliver 100 percent of nominated volumes to its three interconnecting pipelines. Keystone lifted the force majeure effective 9:00 AM on February 7.

Keystone's difficulties did not meaningfully contribute to the curtailments of natural gas customers, but they did affect supplies to gas-fired generators of EPE and SRP. (The failures of EPE's generating units stemmed from other causes,[181] so they would not have been able to utilize the gas in any event; SRP was able to obtain gas from another source.) In order to estimate reduced output per customer, the task force prepared the following table, which compares customer scheduled deliveries with contractual withdrawal rights for the Keystone storage facility. It appears that on the coldest day, February 2, shortfalls were most significant not for NMGC, but for EPE, SRP and the two marketers Sequent and Tenaska.

Keystone Storage Scheduled Deliveries Relative to Contractual Rights

Total (MMbtu)	WD Rights	Scheduled Deliveries	2-Feb	3-Feb	4-Feb
Arizona Electric Power	(6,000)		-	(1,687)	(6,000)
Atmos Energy	(20,000)		(5,096)	(2,009)	(20,000)
BP Energy Company	(17,000)		(2,500)	(7,706)	(17,000)
El Paso Electric	(26,000)		-	(12,730)	(26,000)
New Mexico Gas	(140,000)		(140,000)	(140,000)	(52,510)
Salt River Project	(35,000)		(11,667)	(24,791)	(35,000)
Sequent Energy	(27,000)		(4,793)	(19,125)	(27,000)
Tenaska Marketing	(55,500)		(14,718)	(24,112)	(55,500)
Total	(326,500)	-	(178,774)	(232,160)	(239,010)

Natural Gas Curtailments to Retail Customers

The retail customer is the last link in the natural gas delivery chain, taking gas for home or business consumption from LDCs. LDCs receive their gas from interstate or intrastate pipelines at a delivery point called the "citygate." They distribute the gas through a large network of increasingly smaller diameter pipes to homes and businesses in the distribution area. LDC distribution networks operate at much lower pressures than transportation pipelines, but must maintain certain minimum pressures in order to deliver gas to end users. Some large LDCs use compressors to help maintain minimum delivery pressure, but others rely solely on pressure supplied by the upstream pipelines.[182]

When receipt pressures from the pipelines fall, or when consumer demand for gas exceeds the volume being delivered to the citygate, gas pressure within the LDC network will decline correspondingly. In such instances, LDCs must reduce

[181] The causes of the generating unit outages experienced by EPE are described in the following section of the report, entitled "Causes of the Outages and Supply Disruptions."

[182] NaturalGas.Org, *Natural Gas Distribution*, http://www.naturalgas.org/naturalgas/distribution.asp.

the amount of gas being consumed to prevent pressures from falling to the point where the entire system could fail. LDCs typically do this by first seeking voluntary curtailment from large users. If voluntary curtailment fails to stabilize gas pressure in the system, they will further reduce consumption by cutting off sections of the network, usually beginning with remote sections that would be the first to fail under strained conditions.[183]

State Regulation of Curtailment

Arizona, New Mexico, Texas, and California all regulate curtailments by LDCs in their states, but generally grant LDCs a great deal of discretion in determining how curtailments are implemented.

In Arizona, for example, the Arizona Administrative Code directs utilities to file, as a part of their general tariffs, a procedural plan for handling severe supply shortages or curtailments.[184] The definitions of customer classes and the priority of curtailment are left to the utilities. Southwest Gas's Arizona curtailment rule places residential and other human needs customers at the highest service priority. Electrical generators are classified below that, at priority 2 or 3, depending on the amount of gas they consume.

New Mexico also requires LDCs to create and file a list of customer classifications prioritizing curtailments during a system emergency, but does not prescribe how customers should be ranked.[185] NMGC Original Rule 21 sets forth the company's curtailment priorities, assigning the highest priority to residential and other human needs end users, including suppliers of service to human needs customers.[186] Under the NMGC plan, electrical generators fall within this highest priority category. Zia gives the highest curtailment priority to residential and small commercial or industrial customers.[187]

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[183] Transcript of Testimony of Timothy A. Martinez at 15, In the Matter of an Investigation into New Mexico Gas Co.'s Curtailments of Gas Deliveries to New Mexico Consumers, NMPRC (Apr. 20, 2011) (No. 11-00039-UT).

[184] ARIZ. ADMIN. CODE § 14-2-308(H) (2010).

[185] N.M. CODE R. § 17.10.660.10(E)(1) (2011).

[186] N.M. Gas Co., Original Rule No. 21 IV (2009), *available at* https://www.nmgco.com/Regs/Rule21.pdf.

[187] Zia Natural Gas Co., Second Revised Rule 21 (C) (1997).

In Texas, state law provides that the highest priority of service should be given to "residences, hospitals, schools, churches, and other human needs customers," but LDCs have the authority to set their own priorities, which override the general provisions if the TRC approves the LDC's plan. The TRC-approved plan of Atmos Energy, for example, classifies electric generators several levels below residential customers.[188] Texas Gas Service's curtailment plan gives top priority to residential customers, ranking all commercial and industrial users below them.[189]

The California Public Utility Commission allows LDCs to set curtailment priorities, subject to PUC approval, and it has specifically declined to mandate priority service for electric generators.[190] Both San Diego Gas & Electric Company (SDG&E) and SoCalGas assign the highest priority of service to all residential customers and to small core commercial customers (including some electric generators) that use less than 20,800 therms per month.[191]

Restoration of Gas Service Following a Curtailment

Restoration of gas service to residences following curtailment is a lengthy process that must be performed by trained, qualified personnel. The first step is to shut off each individual gas meter. The LDC's distribution lines and lines from the meters to homes must then be purged of air and re-pressurized with gas. Once this is done, workers visit each home, inspect gas appliances for safety, open meter valves, relight pilot lights, and confirm that the appliances are operating safely. This can only be done when the customer is home, and if workers find that any appliances are not operating properly, service cannot be restored to that home until repairs have been made.

[188] *In re Curtailment Program of Lone Star Gas Co.*, Order No. 496, Docket No. 496 (Texas Railroad Comm'n Oct. 15, 1973).

[189] Curtailments, El Paso Texas Gas Service Area Gas Tariff, Third Revised, § 14.2.

[190] Pub. Util. Comm'n of Cal., Opinion Declining to Provide Service Priorities to Electric Generators in the Event of a natural Gas Shortage, No. 01-12-019 (2001), available at http://docs.cpuc.ca.gov/published/Graphics/11821.pdf.

[191] Annual Notice, San Diego Gas & Electric, Information on Natural Gas Services and Programs (Feb. 26, 2010) (on file with author); *Continuity of Service and Interruption of Delivery Rule 23(B),* SOUTHERN CALIFORNIA GAS CO. at 1, http://www.socalgas.com/documents/business/23.pdf. A therm is 100 MMBtu.

The February 2011 Curtailments

From February 2 through February 4, 2011, LDCs interrupted gas service to more than 50,000 customers in New Mexico, Arizona, and Texas. Areas affected included the cities of El Paso, in Texas (863 customers) Tucson (14,620) and Sierra Vista (4,596) in Arizona, and Hobbs (406), Ruidoso (50), Alamogordo (2,385), Silver City (290), Tularosa (1,445), La Luz (475), Taos (8,505), Red River (557), Questa (548), Española (12,367), Bernalillo (3,172), and Placitas (1,114) in New Mexico.

The New Mexico Curtailments and Outages

Zia Natural Gas Company

The city of Hobbs, in southeastern New Mexico, was the first to experience gas outages. Its LDC, Zia Natural Gas Company, receives gas from DCP Raptor Pipeline, LLC, (DCP) an intrastate pipeline that receives its supply from processing plant tailgates and wellheads. Zia serves approximately 11,000 retail customers in the Hobbs area.

On February 1, 2011, DCP fell behind for a two-hour period on deliveries to Zia because of wellhead freeze-offs and other supplier issues. However, the pipeline made arrangements with the Northern Natural Gas (NNG) pipeline to reverse the flow of gas at a DCP/NNG interconnect near Hobbs, making additional supplies available. Thus, according to both Zia and DCP, DCP's temporary supply shortage did not adversely affect customers in Hobbs.

At approximately 3:00 AM on February 2, an electrical blackout affected approximately 2,065 homes in the northeast area of Hobbs.[192] Zia was not notified of the blackout until approximately 7:30 AM, but at 5:55 AM, the company received a low pressure alarm from a regulator station on the northeast end of the system. Personnel sent to the site reported that pressure was well below normal levels, and Zia immediately contacted DCP, which informed them that a plant had gone out of service due to a cold weather-related mechanical failure and that DCP was attempting to address the problem. The DCP plant in question did not return to service until February 6.

Zia reported that it was able to continue supplying gas to all its customers in Hobbs until approximately 7:30 AM that day, when electric power was restored. At that point, there was a surge in demand as gas appliances that had been unable

[192] SPS is the city's electrical supplier.

to operate without electricity simultaneously came back in service. Almost immediately, Zia began receiving calls from customers reporting that they had no gas or very low gas pressure. In all, 406 customers called in to report supply problems.

Zia believes the reason for the outages was the sudden surge in demand when electric power came back online, coupled with the low line pressures that resulted from the DCP plant outage. That morning, Zia began the process of relighting the primarily residential customers that were affected, and the company was able to restore all gas service by 10:00 PM the same day.

Zia customers in the Ruidoso, New Mexico area also lost gas service as a result of the cold weather events. During the early morning hours of February 3, the Ruidoso area experienced power outages that lasted until 8:00 AM. At the same time, receipt pressures from El Paso were declining.

At approximately 7:30 AM, Zia began receiving complaints of no gas or low gas pressure. Personnel sent to the area reported extremely low pressures, and did what they could to boost flow by bypassing regulator stations. Through a local radio station that was operating on backup power, the company asked the community to cut back on gas use. Pressures were critically low through most of the morning but began to rise just before noon. However, when electrical power was restored, there was a surge in demand that further strained the system. A total of 50 customers at the far reaches of the distribution system lost gas service that day, but their service was fully restored by the end of the working day.

According to Zia, it has no industrial or large load single customers; almost all of its customers are residential or small commercial users. Thus, it was not possible for Zia to reduce demand by curtailing large commercial accounts. Zia believes the Ruidoso outages were caused by high demand on the system, combined with low supply pressures and the surge in demand that occurred when power was restored.

New Mexico Gas Company

NMGC serves more than 500,000 retail customers in towns, pueblos, cities and rural areas throughout New Mexico. NMGC's distribution system is divided into two areas: (1) the north segment, serving the Albuquerque metropolitan area and communities to the north; and (2) the south/remotes segment, consisting of (a) the southeast system, which serves the towns of Roswell, Artesia, Carlsbad, Lovington, Eunice, and surrounding areas, and (b) remote locations, including Alamogordo, Silver City, Clovis, Portales, Tucumcari, Hatch, and Truth or Consequences. The north and the south/remotes segments are served by the

Transwestern and EL Paso interstate pipelines and by other third-party pipelines. The remote locations that lost gas service during the period in question were supplied solely by El Paso.

NMGC: The North Segment

On February 2, 2011, NMGC personnel monitoring the company's north segment, which serves the Albuquerque metropolitan area and communities to the north, noted that gas volumes at the company's receipt points with El Paso and Transwestern were not increasing, indicating that much of the company's nominated gas was not being received. However, although line pack was decreasing, the system was still operating within sustainable limits. Based on additional gas purchases made during the day, the company expected pressures at receipt points to increase at 9:00 PM that night and at 8:00 AM the following morning.

As a precautionary measure, the company began telephoning large commercial users on the morning of February 2, seeking voluntary reductions of gas consumption. NMGC employees, working from a list of the company's 200 largest customers, placed phone calls or sent emails to points of contact on the list. Customers were informed that the company was expecting a gas shortage and that cutting back on gas usage was necessary to maintain service to home, hospitals, and other top priority consumers.

In some instances, large customers agreed to reduce their gas use, either by switching to alternative fuel supplies, lowering thermostats, or shutting down equipment or manufacturing processes. However, some of the customers (approximately 10 percent of those contacted) indicated that they could not or would not reduce their usage.

One of the large customers NMGC contacted was PNM, which operates two gas-fired generating plants in the Albuquerque area. Contacted at 9:42 AM on February 2, PNM responded by stating that no curtailment options were available to it, and that the plants would be increasing their gas consumption to meet power generation requirements.

In other instances, NMGC was unable to reach a point of contact for its large customers and could only leave messages requesting cutbacks or return calls. NMGC estimates that it was ultimately able to contact 30 percent of the top 200 users to request voluntary curtailment.

NMGC was expecting the supply problems to improve at 9:00 PM on February 2, because of the extra gas it had purchased. When line pressure did not

improve at that time, due to the inability of suppliers to put the purchased gas on the system, the company began contacting other pipelines and suppliers in an effort to purchase more gas.

During the early morning hours of February 3, NMGC personnel monitoring line pressure on the north segment, from both the company's gas control center and field locations, believed the system would have enough gas to meet the anticipated morning demand, based on the amount of gas that had been used the previous day. However, beginning at 7:12 AM, the demand for gas rose to unprecedented levels, even though temperatures were only slightly higher than the day before.[193]

Even at this point, however, the company concluded that if pressures at receipt points began to rise at 8:00 AM, as expected based on the additional gas that had been purchased, they would be able to meet the increased demands on the system.

However, pressures continued to decline at 8:00 AM, leading NMGC to conclude that it was in immediate danger of losing the entire system and that they must immediately reduce demand by cutting off sections of the system. At around this time, the company also began receiving reports of no gas or low gas pressure in the Albuquerque area, further indicating that its system was near collapse.

Because NMGC needed to act quickly, and because the distribution systems in the larger metropolitan areas of Santa Fe and Albuquerque were not configured so as to allow curtailment of large numbers of customers by closing just a few valves, the company decided to curtail the areas served by the Taos mainline, which runs from the company's north-south mainline at Otowi junction, located approximately 80 miles north of Albuquerque. That line serves the communities of Española, Dixon, Taos, Questa, and Red River. The Otowi Junction valve was closed at 8:37 AM, cutting off service to those communities.

The company also curtailed two additional communities just north of Albuquerque by closing two valves that supplied the town of Bernalillo at 8:55 AM and 9:14 AM, and by closing one valve to the town of Placitas at 9:29 AM.

[193] NMGC told the task force that although temperatures were slightly warmer on the morning of February 3, compared to the previous morning, demand was nevertheless higher, despite NMGC's efforts to seek voluntary curtailment from large users, and despite appeals through the media for residential customers to conserve gas. NMGC does not know the reason for the increased demand.

If pressures continued to decline, the next step anticipated by NMGC was curtailing sections of the Albuquerque metropolitan area. Curtailment options in that area were limited, however, because of the lack of shut off valves capable of curtailing a large block of customers at one time. The company nevertheless prepared for curtailments by sending a crew with a backhoe to two sections of pipeline that served 2,000 customers, with the intention of digging up the pipes and pinching them off.[194]

At 9:20 AM, following discussions between NMGC and PNM about system conditions, PNM decided to switch its Delta Person (Cobisa) power plant from gas to backup fuel oil. PNM was unable to make the changeover because of a faulty valve, and as a result the plant went out of service and did not draw gas from the system for the duration of the cold weather event.

By 10:30 AM, pressure on the north segment had stabilized and had begun to increase. The restoration process was already underway at that point, as NMGC teams began shutting off meter valves to individual customers so that the lines could be purged and recharged.

NMGC: The South/Remotes Segment

On February 2, line pressure on El Paso's delivery pipeline to NMGC's south/remotes segment steadily declined, dropping below contract pressure[195] at approximately 10:00 AM. As the day progressed, NMGC personnel monitored line conditions and began considering the possibility that if conditions worsened, they would have to curtail certain areas.

At approximately 3:00 PM, NMGC started calling large customers on the south segment to ask them to voluntarily reduce their gas consumption. Some of the larger customers, such as Western New Mexico University, Silver City School System, and the Alamogordo School System, agreed to reduce usage, but two other large users -- Holloman Air Force Base and the White Sands Missile Range -- could not be reached that day, reportedly because the bases were closed because of the weather conditions and the contact persons were not present. (Holloman Air Force Base was successfully contacted the following day at approximately 1:00 AM, and agreed to reduce its usage at that time.)

[194] Transcript of Testimony of Doug Arney at 4, In the Matter of an Investigation into New Mexico Gas Co.'s Curtailments of Gas Deliveries to New Mexico Consumers,, NMPRC (Mar. 17, 2011) (No. 11-00039-UT).

[195] Contract pressure is the minimum gas pressure, measured in pounds per square inch, that a pipeline agrees to provide to a customer at a given delivery point.

Shortly before 5:00 PM on February 2, NMGC received notice from El Paso that line pressure was not expected to improve during the next 24 hours.

At 1:50 AM on February 3, NMGC began cutting off service to schools and non-essential government buildings in Alamogordo. At 2:36 AM, seeing that conditions were continuing to deteriorate, the company declared a system emergency on the south segment.

At 3:00 AM, NMGC cut off service to the communities of Tularosa and La Luz, which are located at the end of the NMGC distribution pipeline that serves Alamogordo. Line pressures continued to decline, however, and at 5:05 AM, the company shut off one section of Alamogordo. At 6:00 AM, the Alamogordo area experienced an electrical blackout. When electricity was restored at 8:00 AM, the resulting surge in demand for gas caused pressure to drop to zero on the southern part of the Alamogordo system, forcing NMGC to cut off that section as well. In all, more than 4,300 customers lost gas service in Alamogordo, Tularosa and La Luz, out of a customer base of approximately 15,000. By 9:25 AM, pressures in the Alamogordo area began to stabilize, and by 3:00 PM that day, the company began restoring service to curtailed areas.

Another community on the NMGC south/remotes segment that lost a portion of its gas service on February 3 was Silver City. According to NMGC, the Silver City distribution network lacked the capacity to meet the unprecedented demand for gas on February 2 and February 3, due to system limitations. NMGC stated that in 2007, it determined that the system's maximum operating pressure should be reduced from 40 psi to 30 psi for safety reasons. With that limitation, the system could not transport the volumes demanded by customers.

Although two large users in that area, the Silver City Consolidated School District and Western New Mexico University, agreed to curtail gas use on February 2, mitigating demand on the system to some extent, pressure continued to drop. NMGC curtailed a section of Silver City at approximately 6:00 AM the following day, February 3, in order to avoid total collapse of the system. Pressure began to recover by 11:00 AM, and restoration efforts began shortly thereafter. A total of 271 out of approximately 9,200 customers in the area lost gas service due to the curtailments.

NMGC has informed the task force that it is in the process of making improvements to the Silver City distribution system that should allow it to meet peak loads of the sort that occurred during the February event.

Restoration of Service

Closing individual gas meters, which is the first stage of restoring service, began shortly after NMGC cut off service on the morning of February 3. In some areas, NMGC personnel began shutting off meters within minutes of the curtailment. As restoration efforts got underway, the company sought additional help through its mutual assistance agreements with the American Gas Association and the Southern Gas Association, whereby member LDCs agree to help each other in emergency situations. That morning, NMGC asked other member LDCs by email and by conference call to send personnel to help them restore service in the affected areas. Out-of-state LDCs responded by sending qualified service personnel, who began to arrive the following day. NMGC also sought help from other New Mexico LDCs, and hired local contractors and plumbers to help restore service. Police, fire department, and National Guard personnel all eventually played roles in the effort to restore service.

Relighting continued through the weekend and into the following week, with a workforce of more than 700 persons participating. Service was restored to some areas as early as February 5, but the statewide relighting effort was not substantially completed until the following week, on February 10.

The Arizona Curtailments and Outages

Southwest Gas, a multistate LDC whose service areas include the cities of Tucson and Sierra Vista in Arizona, was forced to curtail service to parts of those cities on February 3 due to low pressures at receipt points with El Paso. After El Paso declared a system-wide Critical Operating Condition at 11:52 AM on February 2, due to declining line pack and drop offs in gas supply, Southwest Gas's management met at 1:00 PM to plan for increased monitoring of the distribution systems. Shortly thereafter, at about 2:00 PM, the company started calling large commercial customers to alert them to possible curtailments.

At 10:00 PM, as conditions on the El Paso pipeline continued to deteriorate, Southwest Gas concluded that it might be necessary to cut off some customers in order to preserve system operability. When pressures on the Sierra Vista system reached a critical stage at approximately 3:30 AM on February 3, the company identified several sections of the system that should be shut down to reduce demand. At approximately 6:30 AM, crews began closing valves in Sierra Vista and Tucson. Out of a total of 17,801 customers in Sierra Vista, 4,596 were shut off; out of a total of 279,362 customers in Tucson, 14,620 were shut off.

Starting at approximately 5:00 AM on February 3, the company began curtailing several large commercial customers, including an electric power plant in

Tucson. Other commercial users voluntarily curtailed or reduced their use throughout the day.

By 8:30 AM, pressures began to stabilize and recover, and the restoration process was initiated. Southwest Gas brought in 130 employees from other divisions in California, Nevada, and Central Arizona to help with the relighting process, and service was fully restored on the afternoon of February 7, 2011.

The Texas Curtailments and Outages

Texas Gas Service (TGS) serves several communities in Texas, with a total of 616,462 residential, commercial, and transportation customers. The City of El Paso is one of those communities, and during the week in question it was the only city in Texas to experience gas curtailments, with 863 residential customers (out of approximately 231,000) losing service.

Gas is delivered to TGS by the El Paso and ONEOK WesTex Transmission, L.L.C. (ONEOK WesTex) pipelines. Beginning around February 2, TGS received cuts from its suppliers and had to make alternative arrangements to obtain gas for the anticipated cold weather demand, including buying compressed natural gas (CNG) for expedited delivery by tanker truck from Arizona. The company also experienced low delivery pressures from El Paso later that week. However, those factors were not responsible for the service disruptions that occurred. According to TGS, the El Paso system experienced unprecedented demand during the winter event, as much as 41 percent higher than the previous historical peak.[196] The company's distribution system was simply unable to handle that much volume.

Beginning on February 2, at approximately 8:00 AM, residential customers began reporting low pressures. Shortly thereafter, customers in low pressure areas of the system began losing service. TGS responded to each reported outage, and in some instances service was restored the same day. A total of 863 customers lost service during an approximately 24 hour period. Service was fully restored by February 5. The restoration process was hampered by icy road conditions, and by the fact that TGS workers could not restore service when customers were not at home.

In order to alleviate pressure on the system during the period of peak demand, TGS asked ten large transportation customers to reduce consumption at

[196] On February 3, 2011, TGS delivered 258,853 MMBtu to its customers in El Paso. The previous peak at that location was 184,088 MMBtu, in January 2007.

approximately 10:00 AM on February 3. The company also restricted service to 36 commercial customers in areas that were experiencing low pressure, and on February 3, extended a gas main to boost pressures in one of the affected areas. In addition, TGS used two CNG tankers to help deal with low pressure issues. One was used to maintain service to a hospital, and the other was deployed to assist in the restoration process in one of the affected neighborhoods.

TGS plans to make additional system improvements to increase delivery capacity by extending gas mains in several areas that experienced low pressures during the period in question. The cost of these improvements is expected to total more than $1.7 million and the company estimates that they will be completed by September 30, 2011.

The California Curtailments

SoCalGas and SDG&E are separate utility companies, both owned by Sempra Energy. SoCalGas serves approximately 20 million customers in Central and Southern California; SDG&E serves approximately 3.4 million customers in Orange and San Diego Counties, California. SoCalGas operates the natural gas transportation systems of both companies.[197]

Beginning on January 31, 2011, SoCalGas monitored weather developments in the Southwest and was aware of the supply problems that had developed because of the severe cold weather. The company responded to supply shortfalls by increasing withdrawals from on-system storage and by purchasing operational gas to support the southern system, which cannot be served by storage gas. Delivery shortfalls were highest on February 2 and February 3. SoCalGas estimates that the net cost of the operational gas it purchased was $3.81 million, representing the purchase price of the gas less the price at which SoCalGas was later able to sell it.

On the morning of February 3, the company issued a curtailment advisory to non-core (lower priority) customers, informing them that curtailments could occur. At 1:15 PM, due to the continuing severe weather and its effect on production, the company declared a system emergency and curtailed transmission service on its southern system for all interruptible and some firm non-core customers by limiting the amounts they could withdraw from the system.

SoCalGas curtailed 19 interruptible retail non-core and electric generator customers, and 40 firm non-core and electric generator customers. SDG&E

[197] Sempra Energy, *Our Companies*, http://www.sempra.com/companies/companies.htm.

curtailed all its interruptible load and all its firm service to three electric generator customers. SoCalGas reported that its non-core customers and electric generator customers generally complied with curtailment limits during the emergency. When the CAISO informed the two companies that approximately 500 MW of total generation was needed from two of the curtailed electric generators in order to ensure reliable grid operations, SoCalGas and SDG&E adjusted the curtailments so that the two plants could provide the necessary generation.

Resumption of Production

Weather conditions moderated slightly in the Southwest on February 3 and improved further on February 4, rising above freezing for the first time in days. Although production did not return to pre-event levels for several weeks, consumer demand slackened with the warmer weather, and line pack and system pressure rose steadily on the interstate pipelines. As a result, El Paso issued a warning of a system pack condition on February 5, and declared a system -wide Strained Operating Condition for high line pack February 6, 2011.[198]

Impacts of the Event on Natural Gas Prices

Gas prices responded to the winter weather and associated freeze-offs, although the increases were short-lived and not exceptionally dramatic. Some points in the midcontinent and southwest regions did post increases of approximately two dollars to three dollars per MMBtu, which were gains of 40 to 60 percent relative to February 1. West Texas prices were particularly strong with a basis at Waha of $2.60 relative to Henry Hub.[199] Southern California prices at Ehrenberg and Needles also traded higher by $1.77, reflecting upstream supply shortfalls.

The price gains in east Texas and south Texas were more muted, despite the freeze-offs extending to the Gulf Coast, and limited to $0.50 to $0.60 per MMBtu. The Houston Ship Channel, however, had an increase of almost $1.57.

The NYMEX (New York Mercantile Exchange) futures contract was flat to declining for the week. Cash prices at Henry Hub increased by only $0.29.

Most gains were gone by February 5, at which time warmer weather had returned. Prices on February 8 actually traded below those of February 1.

[198] Production figures from Bentek, supporting documentation for *Deep Freeze Disrupts U.S. Gas, Power, Processing* (Feb. 8, 2011); information provided to the task force by pipelines.

[199] Basis is the price differential between, in this case, Henry Hub and Waha.

The following table shows spot prices at a variety of locations for February 1 to February 8.[200] Daily closing prices are also listed for the NYMEX March gas futures contract, which is based on delivery at Henry Hub. The NYMEX price was relatively unaffected by the spot price increases during February 1 to February 8, suggesting that traders viewed the increases as a temporary, weather-related event.

Spot Prices

Flow Date	1-Feb	2-Feb	3-Feb	4-Feb	5-Feb	6-Feb	7-Feb	8-Feb
Waha	$ 4.47	$ 4.79	$ 5.80	$ 7.30	$ 4.76	$ 4.76	$ 4.76	$ 4.25
El Paso-Permian	$ 4.40	$ 4.75	$ 5.74	$ 7.23	$ 4.86	$ 4.86	$ 4.86	$ 4.19
Transwestern-San Juan	$ 4.35	$ 4.66	$ 5.73	$ 6.40	$ 4.49	$ 4.49	$ 4.49	$ 4.11
El Paso-San Juan	$ 4.30	$ 4.51	$ 5.77	$ 6.52	$ 4.51	$ 4.51	$ 4.51	$ 4.10
East Texas, Carthage Hub	$ 4.36	$ 4.42	$ 4.63	$ 4.89	$ 4.49	$ 4.49	$ 4.49	$ 4.28
Houston Ship Channel	$ 4.40	$ 4.37	$ 4.61	$ 5.91	$ 4.43	$ 4.43	$ 4.43	$ 4.29
South Texas, Tennessee Zone 0	$ 4.38	$ 4.39	$ 4.62	$ 5.03	$ 4.40	$ 4.40	$ 4.40	$ 4.28
Oneok Oklahoma	$ 4.49	$ 5.31	$ 7.06	$ 6.28	$ 4.59	$ 4.59	$ 4.59	$ 4.40
SoCal Gas	$ 4.40	$ 4.50	$ 5.47	$ 6.17	$ 4.52	$ 4.52	$ 4.52	$ 4.22
Henry Hub	$ 4.42	$ 4.43	$ 4.55	$ 4.70	$ 4.48	$ 4.48	$ 4.48	$ 4.33
NYMEX Contract	$ 4.42	$ 4.35	$ 4.43	$ 4.34	$ 4.31	$ 4.31	$ 4.31	$ 4.10

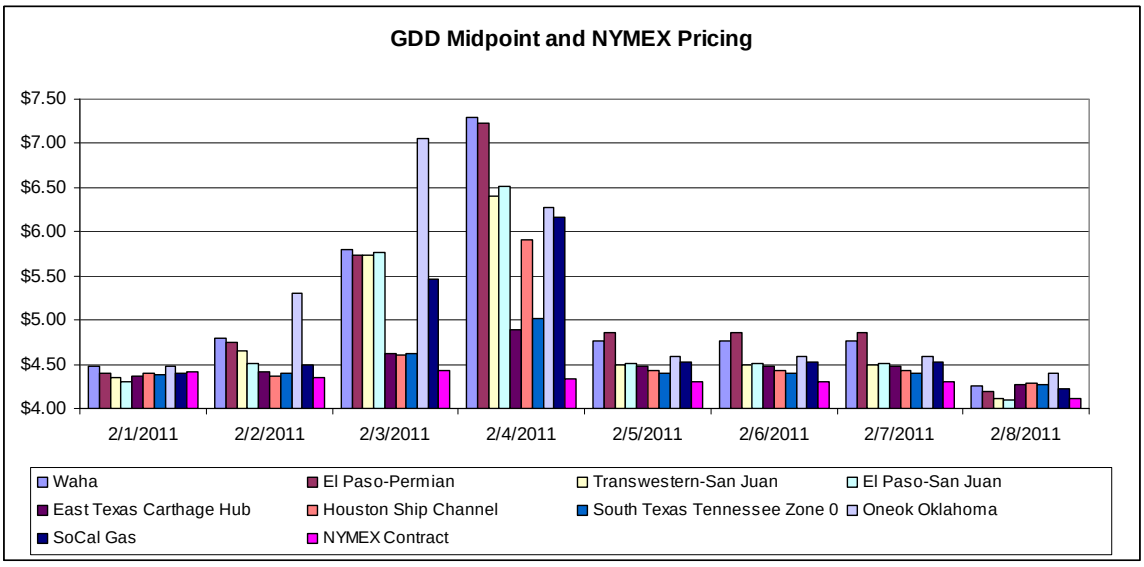
The following table shows the basis for the same locations relative to cash prices at Henry Hub.

Basis

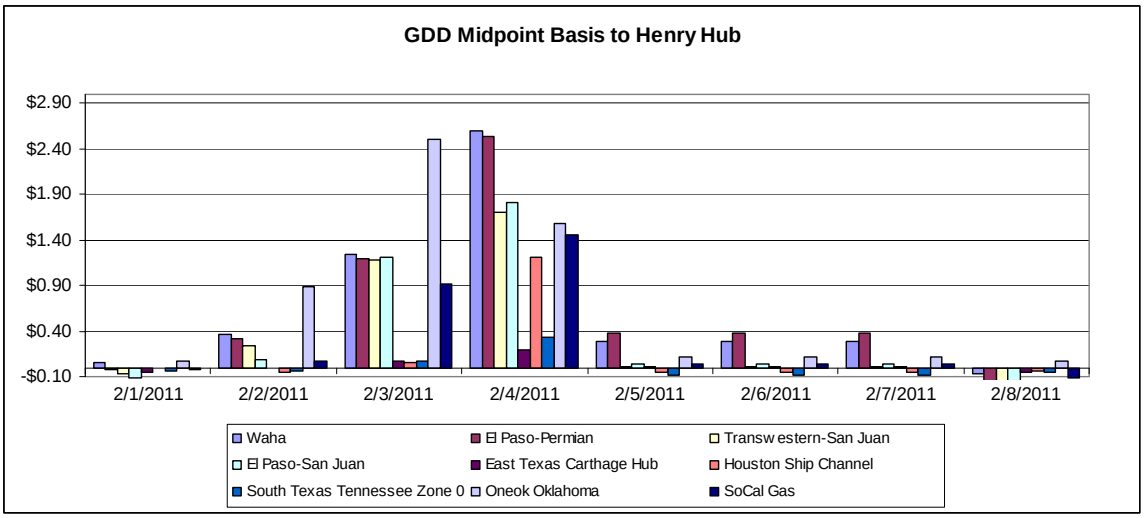
Flow Date	1-Feb	2-Feb	3-Feb	4-Feb	5-Feb	6-Feb	7-Feb	8-Feb
Waha	$ 0.05	$ 0.37	$ 1.25	$ 2.60	$ 0.29	$ 0.29	$ 0.29	$ (0.08)
El Paso-Permian	$ (0.02)	$ 0.32	$ 1.19	$ 2.53	$ 0.38	$ 0.38	$ 0.38	$ (0.14)
Transwestern-San Juan	$ (0.07)	$ 0.24	$ 1.18	$ 1.70	$ 0.02	$ 0.02	$ 0.02	$ (0.22)
El Paso-San Juan	$ (0.12)	$ 0.08	$ 1.22	$ 1.82	$ 0.04	$ 0.04	$ 0.04	$ (0.23)
East Texas Carthage Hub	$ (0.05)	$ 0.01)	$ 0.08	$ 0.19	$ 0.01	$ 0.01	$ 0.01	$ (0.05)
Houston Ship Channel	$ (0.01)	$ (0.06)	$ 0.06	$ 1.21	$ (0.05)	$ (0.05)	$ (0.05)	$ (0.04)
South Texas Tennessee Zone 0	$ (0.04)	$ (0.04)	$ 0.07	$ 0.33	$ (0.08)	$ (0.08)	$ (0.08)	$ (0.05)
Oneok Oklahoma	$ 0.07	$ 0.88	$ 2.51	$ 1.58	$ 0.12	$ 0.12	$ 0.12	$ 0.07
SoCal Gas	$ (0.02)	$ 0.08	$ 0.92	$ 1.47	$ 0.04	$ 0.04	$ 0.04	$ (0.11)

[200] *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 1, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 2, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 3, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 4, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 5, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 6, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 7, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 8, 2011, at 1-2. Reprinted with permission of Platts.

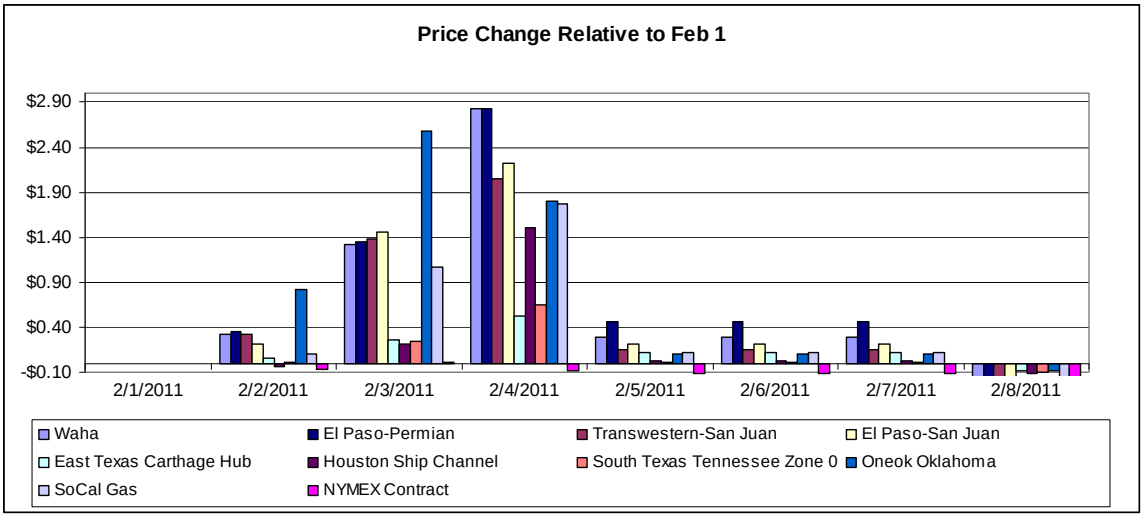
The following three charts show the absolute prices, basis, and price change of natural gas during the week of the event.



Source: Task Force analysis based on Platts data



Source: Task Force analysis based on Platts data



Source: Task Force analysis based on Platts data

The causes of the electric generator failures and the natural gas shortfalls described above are examined in the following section of this report, entitled "Causes of the Outages and Supply Disruptions."

VI. Causes of the Outages and Supply Disruptions

The precipitating cause of the rolling blackouts experienced in Texas and Arizona during the February 2011 cold weather event was the large number of electric generator outages. The principal cause of the gas service curtailments experienced in several southwestern states was the production declines in the supply of natural gas, which led to volume and pressure reductions in the pipelines. The task force has analyzed in detail the causes of these outages and declines, and found that the majority of them were directly or indirectly related to the weather, particularly so with respect to production declines in the gas supply. This section of the report describes in detail those causes, both weather and non-weather-related.

While the storm itself was an uncontrollable event of force majeure, the question arises as to whether the facilities affected should have been better prepared to withstand the severe weather. Was the cold spell so unprecedented that the entities responsible for those facilities could not reasonably be expected to have taken preventative actions? Or did entities fail to take into account lessons that could have been learned from past cold weather events in the Southwest? These questions are addressed in the next section of this report, entitled "Prior Cold Weather Events."

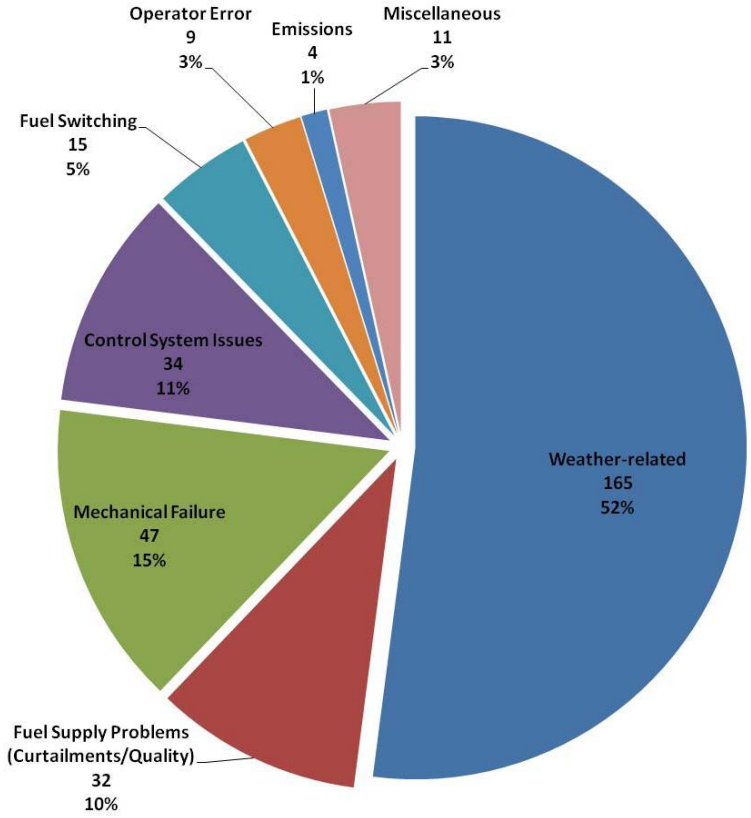
A. Electric

The rolling blackouts that utilities implemented during the cold weather event, which centered in Texas (ERCOT, EPE) and Arizona (SRP), were almost entirely the result of trips, derates, and failures to start of the generating units in those regions. The localized blackouts experienced by PNM in New Mexico, however, were caused by transmission trips. Units in Oklahoma and Kansas also experienced generator outages, but these did not result in blackouts.

The task force has analyzed these various generator outages to determine their underlying causes. By far, the most common cause of the outages was the cold weather, most commonly when sensing lines froze and caused automatic or manual unit trips. There were also several outages that were due to operator error or non-weather-related equipment failures. In a lesser number of cases, an interruption in the supply of natural gas prevented gas-fired units from providing power.

The following two charts[201] and supporting table depict the various causes of the trips, derates, and failures to start[202] for generating units throughout the Southwest, both by number of units and by MWhs.

Southwest - Number of Units Tripped, Derated, and Failed to Start - Feb. 1 - 5, 2011

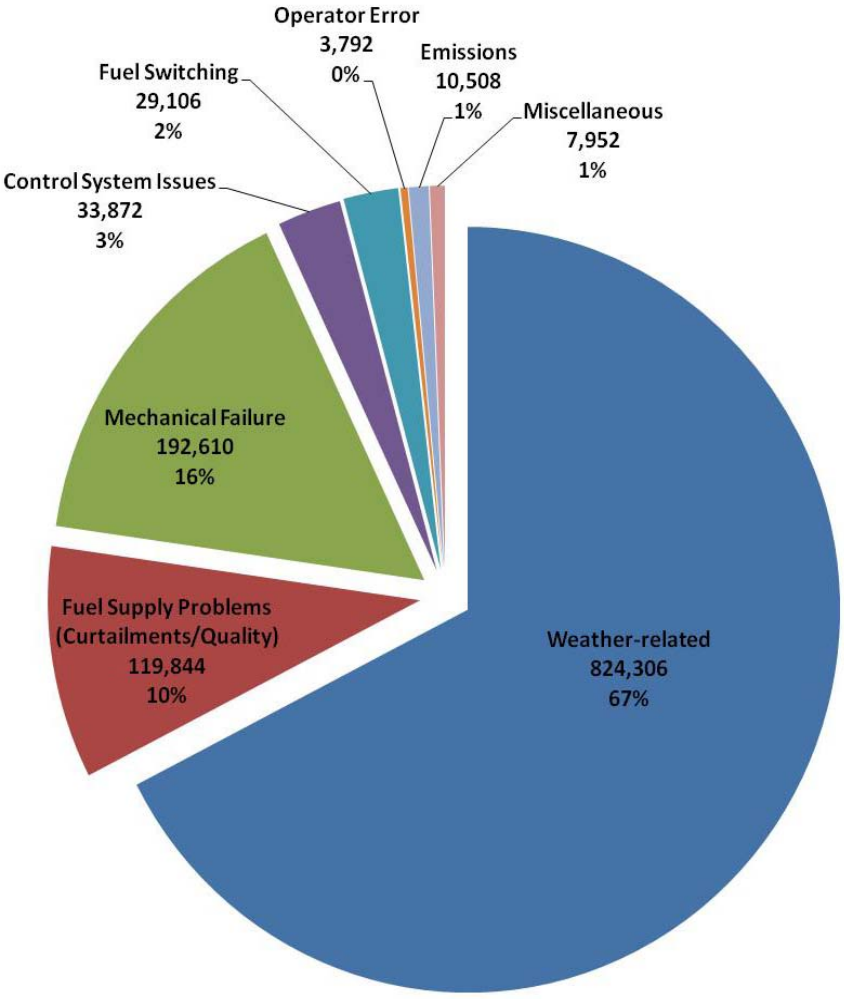


Total Entries in Pie Chart:	317
Total Number of Units Forced Out, Derated, or Failed to Start:	268

[201] Data includes generation in Texas (ERCOT and non-ERCOT), New Mexico, Arizona, and SPP. Units on the first chart are counted more than once if they failed multiple times from different causes (75 units failed on more than one occasion during the event); however, they are only counted once per cause. Data used in the preparation of this chart are drawn from materials submitted to the task force by balancing authorities and generators. Data throughout the section are drawn from materials submitted by transmission operators, generators, producers, processing plants, and pipelines.

[202] Trips totaled 167 units (30,376 MW), derates totaled 57 units (5024 MW), and failures to start totaled 44 units (4743 MW).

Southwest – MWh[203] of Generation Unavailable - Feb. 1 - 5, 2011



Total MWh in Pie Chart*: 1.2 Million
Total MWh of Load Served in affected Southwest Areas: 6.7 Million
Generation unavailable as a percentage of Total MW-hours Load Served: 18%
*Total time period is 106 hours (Midnight going into Feb. 1 through 10 AM Feb. 5)

[203] Megawatt hours were used for this chart to give an indication of the time impact of the outages, derates, and failures to start. (From an operator's perspective, a smaller unit out for a longer time might have a greater impact than a larger unit out for a short time, depending on the circumstances.) To capture this time factor, each instance of unavailable capacity was multiplied by the associated duration of the particular outage or derate and the results were summed.

Supporting Table (Southwest):

Cause	# of Unique Units	MWh
Total Frozen Sensing lines:	89	432,897
Frozen - Drum level sensing lines	48	150,000
Frozen - Other Sensing lines	41	282,896
Frozen Equipment (General)	21	153,393
Frozen Water lines	14	80,091
Frozen Valves	12	20,603
Blade Icing (Wind Turbines)	10	53,989
Low Temperature Limits (Wind Turbines)	17	80,389
Transmission Loss	2	2,944
Fuel Supply Problems (Curtailments/Quality)	32	119,844
Mechanical Failure	47	192,610
Control System Issues	34	33,872
Operator Error	9	3,792
Emissions	4	10,508
Fuel Switching	15	29,106
Miscellaneous	11	7,952

The large percentage of weather-related outages speaks in part to the design and construction of generating facilities in the Southwest. Unlike facilities in cold climates, generating stations in the Southwest are typically designed and constructed so that their boilers, turbines, and other auxiliary systems are exposed to ambient weather conditions. This design prevents heat build-up from occurring in the hot summer months. A more detailed discussion of generating plant design is contained in the appendix entitled “Power Plant Design for Ambient Weather Conditions.”

Sub-freezing temperatures can have adverse operational effects on generating stations if systems containing water do not have sufficient freeze protection, if pneumatic air systems do not have sufficient air drying capacity or freeze protection, or if equipment lubricants are not maintained above prescribed minimum temperatures. Generators with exposed elements typically employ a combination of heat tracing, insulation, wind breaks or enclosures, and heat sources to prevent freezing and to maintain minimum lubricant temperatures. Frozen sensing lines were a particular problem during the February cold weather event, when many generators automatically tripped offline due to faulty readings

from transmitters whose sensing lines froze (most notably steam drum[204] level transmitters).

A detailed examination of the causes of the generator outages experienced within ERCOT, SRP and EPE during the February event, both weather and non-weather-related, is set forth below.

Generation Outages in ERCOT

As a preliminary matter, the task force categorized by age and fuel type the ERCOT units that failed, to determine whether there was any statistical indication that older units or units of a given fuel type were more prone to developing problems. With respect to age, no strong correlation was found. The failure percentage of units with in-service dates before 1981 (19 percent) was actually less than their percentage contribution to the ERCOT fleet as a whole (22 percent).[205] The failure of units with recent in-service dates (between 2001 and 2010) represented 55 percent of the failures, which was slightly more than their contribution to the fleet as a whole (48 percent).

The results are more equivocal with respect to type of unit, where a more significant correlation was found with respect to combined cycle units. Otherwise, however, no significant correlation was found between failure and type of unit. Of ERCOT's combined cycle units, 48 percent failed, compared to their 35 percent of the total. For wind units, 16 percent failed, compared to their 15 percent of total units. For simple cycle units, 21 percent failed, compared to their 20 percent of total units. For gas-steam and coal units, the percentage that failed exactly matched their percentage contribution of total units (13 percent and 7 percent, respectively). Nuclear facilities account for only 1 percent of the total fleet, and no nuclear units failed.[206]

[204] Steam drums are used in boilers (excluding once-through supercritical boilers) to take in a mixture of steam and water coming from the boiler's waterwall tubes. The drum separates the steam from the water by gravity and mechanical separation (such as baffles). The water level in the drum is controlled to keep water in the waterwall tubes and to prevent water carrying over into the steam section of the boiler. The drum also functions to remove solids from the steam.

[205] This statistic and those immediately following are based on number of units, rather than on capacity. (Coal units, for instance, have a larger capacity contribution to the fleet as a whole than seven percent, which is their percentage contribution based on number of units.)

[206] The totals do not add up to 100 percent because certain other facilities have not been taken into account, such as hydro facilities and storage facilities.

For purposes of further analysis, the task force sorted by unit[207] the ERCOT generator trips, derates, and failures to start into three broad categories: weather-related, non-weather-related, and fuel supply. (The weather-related category considers only failures directly related to the weather; problems of insufficient fuel supply as well as outages and derates resulting from fuel switching, although indirectly related to the weather, are listed separately.) Direct weather-related causes accounted for 52 percent of the total failures, non-weather-related causes for 40 percent, and problems with fuel supply for nine percent.[208] Sub- categories within these major groupings, as well as specific examples of the various types of failures, are provided below.

ERCOT Weather-Related Outages and Derates

The task force identified the various specific causes for the trips, derates, or failed starts in ERCOT between February 1 and February 5 that were due directly to the cold weather.[209] (Some of the other failures experienced by ERCOT generators, such as reduced supplies of natural gas, were indirectly related to the weather.) The task force has identified the specific causes of these weather-related failures, by number of units and number of MWs:

Cause	No. of Units Lost	MW Lost
Frozen Sensing Lines (Total)	68	15,255
Frozen Drum Level Sensing Lines	(43)	(9438)
Frozen Other Sensing Lines	(25)	(5817)
Frozen Equipment (General)	13	2942
Frozen Water Lines	12	1072
Frozen Valves	8	1501
Blade Icing (Wind Turbines)	10	709
Low Temperature Limits (Wind Turbines)	17	1237
Transmission Loss	2	89
Total Weather-Related	**130**	**22,805**

[207] A unit that failed multiple times for different reasons is counted under each separate reason; if it failed multiple times for the same reason, it is counted once. That convention applies as well to the three charts detailing ERCOT's weather, non-weather, and fuel failures.

[208] Numbers add up to slightly higher than 100 percent due to rounding.

[209] The weather effects stemmed not only from the prolonged cold, but from high wind chill factors. Although typically thought of as applying to living beings, wind chill also more quickly cools inanimate objects, such as water pipes, bringing them down to the current air temperature. Wind also causes the loss of radiant heat, which otherwise can protect equipment from freezing. This phenomenon is discussed at more length in the appendix entitled "Impact of Wind Chill."

A sample of the ERCOT generating units that experienced weather-related failures, categorized by the specific cause of failure, provides some insight into the variety of concerns with which the generator operators had to contend during the event, and illustrates the complexity of the protections needed for generating plant systems.

- **Frozen Sensing Lines:** Instrumentation provides operational data necessary to monitor and control the generator's systems. Typically, sensing lines containing a standing water column sense changes in pressure and a transducer produces an electronic signal that is transmitted to instrumentation or controls. In sub-freezing temperatures, if freeze protection is not employed on critical unit systems, the water in the sensing lines freezes, causing faulty signals and subsequent unit trips or derates. During the February event, frozen sensing lines were the leading cause of outages, with steam drum sensing lines being the most prevalent (43 units tripped from this cause alone).

  - ✓ JK Spruce Unit 2, a 785 MW coal unit, tripped due to frozen sensing lines that caused a false high water level reading in the steam drum.

  - ✓ Ingleside Cogeneration lost two units due to frozen sensing lines. The lines were heat traced, but the ground fault interrupter breakers protecting the heat trace circuits tripped, resulting in a loss of 176 MW.

  - ✓ Another unit tripped due to frozen sensing lines on feedwater heater level controls. The freezing caused a high condensate level in a feedwater heater, which in turn incorrectly initiated a trip of the unit.

  - ✓ Non-drum sensing line failures included a unit whose vacuum system became erratic when the sensing line to the auxiliary steam pressure indication froze. Another unit tripped when the sensing lines to the rotor air cooler level transmitters froze.

Sensing Lines and Frozen Transmitters

There were many reports of frozen transmitters causing generating units to be forced offline during the cold weather event. In almost all cases, it was not the transmitters themselves that froze, but rather sensing lines filled with standing (non-flowing) water routed between the transmitters and the points the sensing lines are measuring.

(cont'd)

Transmitters

The transmitter assemblies perform three distinct functions. First, they detect the difference in pressure between two water lines, typically with a diaphragm-type sensor that deflects in the direction of, or towards, the lower pressure. Second, they serve as transducers that translate the pressure difference into an electrical signal. Third, they boost or otherwise process the signal for transmitting to the plant's control room, generally using electronics.

Differential Pressure Measurement

The technique of measuring the pressure difference (differential pressure) between two sensing lines filled with water has widespread application throughout power plants, especially in steam-powered generating units. This is due to the fact that differential pressure can be used to provide not just a measure of pressure itself, but also of water levels and flow rates. Significant applications include the following:

- **Pressure Measurement**
  - Between a boiler feedwater pump and the steam drum
- **Water Level Measurement**
  - In feedwater heater tanks
  - In the deaerator tank
  - In the steam drum
- **Water Flow Measurement**
  - Feedwater flow
  - Generator stator cooling water flow

Water Level Measurement

Differential pressure can be used to measure water level by virtue of the force of gravity, which results in greater pressure as the water level increases. This is akin to the hydraulic head resulting from water in an open reservoir, which is a measure of water pressure compared against standard atmospheric pressure. The method needs to be modified, however, to account for the fact that the space within a tank above the water is pressurized. Hence the use of differential pressure measurement, with one sensing line connected to the bottom of the tank to sense the water pressure, and the other to the top of the tank to sense the water vapor or steam pressure. The line at the top of the tank is known as the reference line. Even though the reference line connects to the top of the tank, which is above the water level, it will itself still fill up with water because the vapor/steam condenses in the line due to the much cooler ambient air temperature external to the tank.

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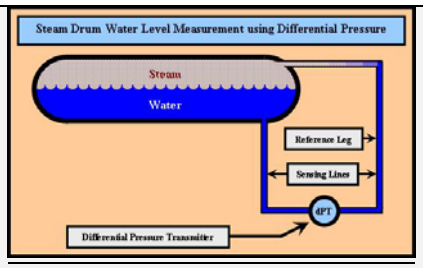

Water Flow Measurement

Differential pressure can be used to measure water flow by virtue of Bernoulli's principle: an increase in the speed of a flowing fluid is accompanied by a decrease in pressure. This increase in speed can be forced by placing a constriction such as an orifice plate or nozzle inside a pipeline, reducing its effective diameter. In order for the rate of flow in gallons per minute, for example, to remain the same, the velocity of the fluid must increase to make up for the fact that it is travelling through a smaller opening. This phenomenon is known as the Venturi effect. The higher velocity translates into lower pressure by Bernoulli's principle. Thus, measuring the differential pressure on either side of the constriction provides a measure of the rate of flow through the pipeline.

For exact flow measurement, the design and dimensions of the constriction are critical. In some cases, however, the concern lies more with changes in flow rate, indicative of blockages in the piping or overall flow path. This concern is important when strainers are used to filter out undesired particles from the fluid, especially in generator stator cooling systems. The strainers provide constriction to the water flow, resulting in a pressure difference. When the strainers are clogged, the pressure difference increases.

Steam flow can also be measured using the Venturi effect. But in that case, long sensing lines are not needed, as pressure immediately on either side of the orifice plate or nozzle is measured.

The Freezing Problem

Since differential pressure measurement requires gauging the difference in pressure between two separate sensing lines, if the water in either or both of those lines freezes, the measurement will be false. When a sensing line is plugged with ice, it cannot convey the intended water pressure to the transmitter location.

The fact that the water in the sensing lines is not flowing makes freezing all the more likely, and emphasizes the need for proper freeze protection methods such as insulation and heat tracing. Some sensing lines must run long distances through areas exposed to outdoor ambient air, which significantly exacerbates the risk of false readings.

- **Frozen Equipment (General):** Many other critical systems besides sensing lines experienced problems from the low temperatures. These included emissions systems, feedwater systems, control air systems, lubricating oil systems, and the like. Emissions systems sometimes rely on water, which is susceptible to freezing. Control air systems contain moisture-laden air; if the moisture is not removed, freezing can occur. Changes in the viscosity and properties of lubricants that are not kept at specified temperatures can adversely affect the operation of equipment.

  - ✓ Two units at one plant were derated when the NOx water storage tank lines froze.

  - ✓ At a City of Garland unit, 78 MW were lost from a draft fan failure, which was caused by frozen damper controls and a resulting low air flow trip.

  - ✓ A wind facility lost six units when lubricating oil fell below the minimum operating temperature and automatically tripped the units.

- **Frozen Water Lines:** The condensate and boiler feedwater systems of steam-cycle generating units (coal, conventional gas, and combined cycle) utilize water from the condenser and add heat (through a series of feedwater heaters) and pressure (through condensate and boiler feedwater pumps) to increase cycle efficiency before the water enters the boilers. Piping, pressure vessels, and valves contained in these systems are susceptible to freezing, absent freeze protection measures. (This is especially true if the unit is offline at the onset of freezing temperatures.)
  .

  - ✓ One facility lost a 160 MW unit when air compressor drains froze. Another unit was shut down because of high boiler "superheat" temperature when its superheat spray lines froze.

- **Frozen Valves:** The operation of valves can become sluggish when exposed to severe cold weather. Depending on the particular application of these components, sluggish valves can cause instability in the boiler or turbine controls, which can eventually lead to a unit trip.

  - ✓ Kiowa Power Partners attempted to free up a frozen valve and, in the process, shut the valve completely, cutting off steam to the turbine and tripping 307 MW of capacity.

  - ✓ Another generating unit experienced a frozen valve on a fuel gas temperature controller, which caused gas temperatures to become

erratic. A bypass valve on another unit's fuel gas temperature controller froze, preventing the unit from reaching full capacity for a period of time.

- **Blade Icing:** Blade icing caused problems for wind generators. Precipitation and condensation during cold weather can cause layers of ice to form on turbine blades, causing potential balancing, bearing, and other equipment problems (as well as safety problems resulting from "ice throws").

  - ✓ Turkey Track Wind Energy lost 27 turbines and 40.5 MW of capacity during the event due to blade icing problems.

- **Low Temperature Limits:** Wind turbines are typically designed to operate within a designated range of temperatures, and have an automatic shutdown feature to protect their components if the range is exceeded. Although manufacturers offer a "cold weather package"[210] that allows a turbine to continue operating in colder temperatures, it does not appear that the package is used in the Southwest.

  - ✓ McAdoo Wind Energy suffered outages of 90 of its 100 turbines when the turbines, designed to shut down when the temperature drops below five degrees, performed as expected. Although McAdoo's turbines restarted automatically when the temperatures rose above the shutdown point, other units, such as Bull Creek Wind, did not come back online as temperatures rose.

- **Transmission Loss:** Generators can also be affected by external outages of transmission facilities.

  - ✓ At one generating plant, cold grease in a breaker appears to have caused slow clearing of the breaker, tripping six units.

[210] Press Release, General Electric, GE Energy's 2.5xl Wind Turbine Now Offers Extreme Cold Weather Capabilities for Challenging Applications in North America and Europe (Sept. 21, 2009), *available at* http://www.genewscenter.com/content/Detail.aspx?ReleaseID=8415& NewsAreaID=2.

ERCOT Non-Weather-Related Outages and Derates

While the majority of the ERCOT generator failures during the February event were weather-related, other causes also played a part. This is not surprising, as on any given day generating units can and do experience problems. To determine whether the amount of non-weather-related failures during the February cold weather event was typical, the task force reviewed ERCOT's 2010 daily forced outage data. During that year, forced outages ranged from 900 MW to 6300 MW per day, averaging 3200 MW per day or 16,000 MW for a five-day period. Therefore, the task force concluded that the 14,386 MW of non-weather-related failures experienced by ERCOT generators between February 1 and February 5, 2011 were comparable to what might be expected over a normal five-day period.

The causes (other than fuel supply) of the non-weather-related outages between February 1 and February 5 included difficulties with mechanical equipment, control equipment, operator error, emissions limitations, and fuel switching failures. The task force identified six general categories of non-weather-related causes of generator trips, derates, and failed starts over these five days:

Cause	No. of Units Lost	MW Lost
Mechanical Failure	37	7588
Control System Issues	28	3624
Fuel Switching	12	909
Operator Error	9	980
Emissions	3	358
Miscellaneous	11	927
Total Non-Weather-Related	**100**	**14,386**

Representative problems within these categories are discussed below.

- **Mechanical Failure**: A number of generators experienced mechanical equipment problems that were not related to the cold weather. For instance, several had combustion turbines trip due to high exhaust temperature spreads, which is an indicator of internal problems with the combustion turbine (or with the thermocouple[211]). Another common combustion turbine problem encountered during the event was high blade path

[211] Thermocouples are used to measure process temperatures and consist of two dissimilar metal wires soldered together at the tip, which produce an electrical current in response to temperature changes. Thermocouples can fall out of calibration over time or fail suddenly due to broken wires or damaged lead wire insulation.

spread,[212] which resulted in several more trips. Other trips, derates, and failures to start resulted from such problems as boiler and heat recovery steam generator leaks, plugged suction strainers on condensate pumps, improper boiler feed water pump oil pressure, gas pressure regulation issues (which were mainly resolved by the pipelines), and an assortment of gas turbine tuning issues.

- ✓ Greens Bayou CT 81 (54 MW) tripped due to a high combustible gas alarm, which was triggered by a leak in a coupling.

- ✓ San Miguel Unit 1 (395 MW) tripped due to a waterwall tube leak.

- **Control System Issues:** A prominent problem with control equipment appears to have been failed thermocouples. Control parameters, logic, and dynamics probes also resulted in several trips. Other problems included, but were not limited to, malfunctioning flame detectors and sheared air register pins,[213] loose wiring, a failed speed sensor, broken control linkages and faulty flow meter switches.

  - ✓ Deer Park CT 1 (195.5 MW) tripped due to a blade path temperature spread resulting from a failed sensor in the plant's distribution control system logic.

  - ✓ One facility experienced problems with its 46 relay,[214] which caused an outage. Another unit had a false indication of a ground fault on a generator rotor, which prompted the operator to take the unit offline.

- **Fuel Switching:** ERCOT has approximately 90 generating units with fuel switching capabilities, permitting them to switch from natural gas to an alternate fuel when natural gas is in short supply. (Generators may wish to switch fuel for other reasons as well, such as economics.) During the February event, 20 units attempted to switch from natural gas to their

[212] Blade path spread is a measurement, utilizing thermocouples, designed to identify turbine exhaust temperatures. A temperature spread beyond allowable limits will initiate an alarm or a trip. However, the alarm or trip can also be triggered by a defective thermocouple, rather than by actual fuel problems or air cooling problems.

[213] The failed flame detectors and air register pins caused burners inside the boiler to malfunction.

[214] A 46 relay (negative sequence relay) is used to detect unbalanced load on a generator that may cause excessive rotor heating and result in significant damage to the generator.

alternate fuel, with 15 units managing the switch successfully. The other units encountered various failures in their switching equipment. Derates also resulted from fuel switching.

- ✓ The Decker CT 2 (54 MW) tripped when attempting to burn fuel oil.
- ✓ The GEUS steam plant was derated by 5 MW due to operating on fuel oil.

- **Operator Error:** Several generators experienced minor problems associated with operator error. In some cases, the problems arose when operators switched control systems from automatic to manual mode. In other cases, generators tripped as the result of improper maintenance procedures.
  - ✓ A flameout of the boiler at one unit forced the burner valves to close but left the main gas trip valve open. In attempting to close the trip switch before restarting the unit, an operator selected the trip switch for the second unit, putting the second unit out of service.
  - ✓ An operator noticed that the fuel forwarding system for two units were operating in the incorrect mode. In attempting to rectify this situation, the operator correctly selected the automatic mode for one pump (it was operating in manual), but mistakenly selected "lagging" instead of "leading." This caused both units to give low pressure alarms and trip offline.
  - ✓ Hydraulic oil heaters at a generating unit had been left unplugged since the summer of 2009 (they had been unplugged at that time to avoid overheating). During the February event, trips resulted from low hydraulic oil temperatures.

- **Emissions:** At approximately 12:00 PM on February 2, ERCOT informed generators that the Texas Commission on Environmental Quality (TCEQ) was temporarily waiving air permit requirements that were preventing some generators from operating at full capacity during the emergency. (Although ERCOT characterized the action as a waiver, the TCEQ actually stated that it was exercising enforcement discretion.) This decision had little effect on the situation within ERCOT, as it was not announced until after half of the shed load had been restored.
  - ✓ Prior to issuance of the notice, Calpine's Clear Lake facility, which consists of three combustion turbines and two heat recovery steam

generators, was forced to manually shut down its GT102 and GT104 turbines in order to avoid exceeding NOx Limits.

- ✓ On February 3, another Calpine unit, Freestone Unit GT4, was derated so as not to exceed its NOx permit limits.

- **Miscellaneous:** A variety of other problems was also experienced, such as the following:

  - ✓ **Switchyard Equipment Problems:** Some generators encountered switchyard problems that led to units failing during the event. One entity was unable to start certain units because a standby transformer was not energized.

  - ✓ **Low Frequency Related Issues:** Two facilities reported frequency-related issues as causes for their units tripping. One facility's three generators tripped as a result of a low frequency turbine protection relay operating improperly. At another facility, the decline in frequency during the event caused the turbine control system to initiate an increase in fuel pressure to increase turbine speed, but it overshot its set point.

ERCOT Gas Supply Outages and Derates

Fuel supply problems did not significantly contribute to the amount of unavailable generating capacity in ERCOT during the first week in February. The outages and derates from inadequate fuel supply totaled 1282 MW from February 1 through February 5. (For comparison, the overall net generating capacity reduction in ERCOT peaked at 14,702 MW on the morning of February 2.) The fuel supply problems also did not occur all at the same time. The following table summarizes generation capacity reductions in ERCOT due to fuel curtailment and fuel quality problems.

Generator	Trip Time	Unit	Gen MW	MW Reduction	Pipeline (s)
Bosque Power Company	2/2 9:26 AM	Bosque Power: Unit 1, Unit 2, Unit 3, and Unit 4	597	154	Enterprise Texas Pipeline, Markwest Lateral
Calpine	2/4 7:55 AM	Corpus Christi: GT1, GT2, and ST1	516	174	South Cross CCNG Transmission
City of Austin (Austin Energy)	2/2 7:30 AM	Decker : Unit 2	450	100	Enterprise Texas Pipeline / Atmos Texas Pipeline
Power Resources	2/2 5:14 PM	Cal Energy: Unit 1	212	7	ONEOK WesTex Transmission
Luminant	2/1 10:00 AM	Lake Hubbard: Unit 1	441	174	Atmos-Texas Pipeline
GEUS	2/1 9:00AM	GEUS Steam Plant	112	112	Atmos-Texas Pipeline
Exelon	2/1 7:30 PM 2/2 11:00 AM 2/2 3:00 PM 2/2 6:00 PM	Mountain Creek: Unit 6, Unit 7, and Unit 8	808	476 396 476 396	Atmos-Texas Pipeline and Energy Transfer Fuel
Frontera Generation	2/2 8:16 AM	Frontera: Unit 1, Unit 2, and Unit 3	485	85	Kinder Morgan Tejas

- **Bosque Power Company:** MarkWest PNG Utility operates an intrastate, 30-mile, 18 inch diameter lateral in Hill, Johnson, and Bosque Counties, Texas. The lateral has an operating pressure of approximately 700 psi, and has no compressor stations. Gas is transported from Enterprise Texas Pipeline, a second intrastate pipeline, to the Bosque County Power Plant, the only electric generation facility served by the pipeline.

Bosque Power Company's QSE, EDF Trading North America (EDF), manages all transportation and gas supply purchases, nominations, and scheduling, including capacity on the Enterprise Texas Pipeline. EDF has only interruptible capacity on the Enterprise Texas Pipeline. The majority of its receipt points are in Waha and West Texas.

The power plant's units are programmed to automatically shut down if pipeline pressure drops below a certain point. On February 2, gas pressure steadily dropped to near the automatic shut down point. To mitigate the effects of lower gas pressures, the plant began reducing energy output on all four of its units.

MarkWest informed the task force that there are no compressors on their pipeline, and therefore the declining pressure was likely a gas supply issue. The pipeline had no capacity constraints.

- **Calpine:** The Calpine Corpus Christi facility is supported by one pipeline system, the Southcross CCNG Transmission pipeline (Southcross). Calpine Energy Services (CES), a subsidiary of Calpine Corporation, is an energy marketer that arranges for natural gas supplies for generation facilities owned by Calpine, including the Corpus Christi facility.

  On February 3 and 4, CES delivered gas into Southcross at four separate locations. However, at approximately 7:55 AM on February 4, the Calpine units tripped off line due to declining pipeline pressure on the Southcross system. The pressure on Southcross fell below the minimum delivery pressure obligation of 560 psig that is stated in both of CES's firm and interruptible agreements. Southcross reported that the low pressures on its system were due to supply freeze-offs that reduced expected deliveries into its system.

  Calpine was able to restart one of its units in less than one hour and run the facility at a derated level. Later in the day on February 4, once Southcross restored its line pack pressures, Calpine successfully brought all units back online.

- **City of Austin (Austin Energy):** The city of Austin has firm capacity on the Enterprise Texas Pipeline and is connected to the Atmos Pipeline-Texas (Atmos), both intrastate pipelines. Under the terms of the city's agreement with Atmos, its capacity rights are reduced when freezing weather is forecasted, pursuant to a specific formula in the contract. Most of the gas supply for the transportation is from Waha.

The plant did not experience curtailments. However, given the limitations on Atmos, usage was limited on February 2. Austin Energy exceeded its contractual hourly take on Enterprise Texas Pipeline and was requested by Enterprise to reduce flows to the hourly take (this is referred to as "back on rate"). This reduction caused a 100 MW derate of the Decker unit.

- **Power Resources:** Power Resources' Cal Energy Plant ramped down one hour early due to low gas pressure on its supplying pipeline, ONEOK WesTex, an intrastate pipeline located primarily in west Texas and the Texas panhandle.

  ONEOK WesTex states that it did not interrupt service but did experience operational difficulties and supply reductions. Beginning on February 1, increased gas usage by towns and power plants reduced the pipeline pressure, and several interconnecting gas processing plants also experienced supply difficulties. Normal operating pressures were restored by the afternoon of February 2.

- **Luminant and GEUS:** These plants are connected to the Atmos system, which traverses the Fort Worth, Permian, and East Texas Basins, all of which experienced supply losses due to freeze-offs.

  Transportation for power generation feeding off Atmos is only offered as an interruptible service, and is subject to electric generation restrictions, called "Tier 3 restrictions." Atmos instituted Tier 3 restrictions beginning at 9:00 AM on February 1, restricting gas flow to zero for the GEUS steam units and for Luminant's Lake Hubbard generating station. On February 2, increased demand resulted in continued loss of line pack and declining pressures at citygate points in Dallas-Fort Worth. Additionally, suppliers experienced well freeze-offs and equipment problems.

  On the morning of February 2, ERCOT initiated rolling blackouts to maintain the grid. The TRC contacted Atmos at approximately 10:00 AM to ask if additional volumes could be delivered to the Lake Ray Hubbard Electric Generating Station to assist with electric grid issues. Atmos explained to the TRC that such action would result in the loss of service to firm residential and commercial customers served by LDCs located to the north of the electric generation station on the pipeline system, and that therefore such deliveries could not be made to an interruptible customer.

- **Exelon:** Exelon has a firm gas transportation contract with Energy Transfer Fuel (ET Fuel) for the Handley Generating Station and an

interruptible gas transportation contract with Atmos for Handley Generating Station and Mountain Creek Station. Atmos implemented a Tier 3 restriction during the extreme weather event, which limited hourly flow to both the Handley and Mountain Creek stations.

The fuel curtailments at Handley did not affect operations until Unit 3 was called on the evening of February 2. Gas supply during the day was enough to allow Units 4 and 5 to run at full load. When Unit 3 was brought on line, it fuel switched Unit 4 to run partially on oil to allow Units 3 and 5 to increase output. Mountain Creek Units 6 and 7 ran at minimum load due to fuel restrictions. Mountain Creek Unit 8 ran at full load (but did have other non-gas related derates that affected output).

- **Frontera Generation:** The Frontera Generation plant is on the Kinder Morgan network of pipelines (collectively, KM Texas Pipes). The KM Texas Pipes receive natural gas from producing fields in south Texas, east Texas, the Gulf Coast, the Gulf of Mexico, and the Permian Basin. They also own or control gas storage capacity.

  Frontera has firm transportation service with deferred account service. "Deferred account service" is a balancing service that enables a shipper to acquire supply during low demand and deliver it to the KM Texas Pipes for future redelivery during peak demand, subject to contractual limits on hourly, daily, and total quantities.

  During the morning of February 2, the KM Texas Pipes contacted those customers that were taking more than their firm contractual rights, including both of the Frontera plants, requesting they stay within their contractual rights because pipeline pressures were falling and putting all firm services at risk. Later that day, ERCOT, along with the TRC, advised the KM Texas Pipes that ERCOT had declared an emergency condition. ERCOT then advised the KM Texas Pipes that the power grid in the Rio Grande Valley was in a critical state. ERCOT and the TRC requested the KM Texas Pipes to allow the Frontera electric generating plant to pull supplies in excess of their firm contractual rights. The KM Texas Pipes complied with this request.

Generation Outages in Salt River Project

The SRP balancing authority suffered several generator outages during the cold weather event, which severely affected its ability to serve load. On February 1 and 2, SRP lost a total of seven units. The failures of three of them were related to weather. On February 1, SRP lost Unit 1 at its Navajo Generating Station due

to a frozen transmitter sensing line, reducing generation capacity by 330 MW. On February 2, SRP lost additional generation due to weather-related problems: it lost 75 MW, its 10 percent share, from Unit 4 at Four Corners Generating Station (operated by Arizona Public Service Company), which failed due to a frozen sensing line that served the throttle pressure transmitter; and it lost Unit 2 at Navajo Generation Station, which tripped due to frozen waterwall pressure transmitter sensing lines.

SRP also suffered generation losses from the trips of four units on February 2, due to non-weather related issues: Coronado Generating Station Unit 2 , which experienced a mechanical problem with a coal pulverizer, losing peak load of 389 MW; the combustion turbine and the steam turbine units at Santan Generation Station Unit 6, which suffered an internal mechanical failure on the heat recovery steam generator and an accompanying runback of the combustion turbine; Springerville Unit 3 (operated by Tucson Electric Power), which developed high furnace pressure, causing a loss to SRP of its 75 MW share of the plant's 400 MW.

Generation Outages in El Paso Electric

The EPE balancing authority shed approximately 623 MW of firm load over the course of the February event, due to the loss of 646 MW of local generation. Unlike SRP, almost all of EPE's's outages were due to the cold weather.

On February 1, EPE lost its Newman Unit 3 because of frozen condensation on the fresh air inlet, and lost Rio Grande Unit 6 because of a frozen gas transmitter. The loss of these units resulted in a 152 MW reduction of capacity.[215]

On February 2, EPE lost 495 MW of capacity from its Newman and Rio Grande plants. Newman Gas Turbines 1 and 2 at Newman Unit 4, each with a capacity of 73 MW, tripped due to faulty drum level readings resulting from the cold weather. Gas Turbines 3 and 4 at Newman Unit 5, each with a 70 MW capacity, also tripped due to frozen drum level instrumentation sensing lines. Newman Unit 4 Steam Turbine, a 64 MW unit, tripped on February 2 due to frozen instrumentation associated with the condenser vacuum. Finally, EPE lost Rio Grande Unit 8, a 145 MW unit, due to frozen transmitter sensing lines that caused a low gas pressure signal.

[215] The Newman plant is not enclosed; the Rio Grande plant is enclosed.

El Paso attempted to bring its units back online on February 3 and February 4, with limited success. Newman Unit 4's GTs were restarted, only to trip on subsequent occasions for similar weather-related issues. (Luna and Afton, PNM remote generating facilities from which EPE was receiving energy, also experienced outages on February 3 and February 4.)

During the event, two EPE units, Newman Unit 1 and Rio Grande Unit 7, were offline and EPE tried to bring them online to assist with the shortages. Both units, however, failed to start due to frozen components and, in the case of Newman Unit 1, frozen drum drain lines and transmitter.

B. Natural Gas

Most of the natural gas supply problems experienced in the Southwest during the cold weather event were caused by freeze-offs, principally at the wellhead or, to a lesser degree, at nearby processing plants. Other equipment failures also played a role, as did the rolling blackouts and customer curtailments in the ERCOT region.

In order to analyze the causes of the supply shortfalls, the task force reviewed daily shortfalls at receipt points on pipelines. Most of these receipt points were at processing plants. The following table summarizes the information received from 13 processing companies, which overwhelmingly pointed to upstream supply outages as the major cause of the reduced volumes. (The second column is the maximum estimated production shortfall by basin; the third column is the percentage of shortfall of the processing plants that provided information; the final column lists the causes of the shortfalls.)

Processing Plant Outages Relative to Daily Production Shortfalls

BASIN	MAXIMUM DAILY PRODUCTION OUTAGE	PROCESSING RESPONSES AS A % OF THE DAILY OUTAGE	CAUSES
Permian	1.31 Bcf on Feb 4	0.44 Bcf (34%)	85% Upstream Supply Freeze-offs, 15% Mechanical/Electricity Outages
San Juan	.43 Bcf on Feb 2 and Feb 3	0.21 Bcf (52%)	Upstream Supply Freeze-offs, Minimal Amount due to Mechanical
Fort Worth	1.63 Bcf on Feb 6	0.17 (11%)	Upstream Supply Freeze-offs, Minimal Amount due to Mechanical
East Texas	.72 Bcf on Feb 3 and Feb 5	NA	NA
Gulf Coast	.65 Bcf on Feb 4	NA	NA

The task force further explored these upstream production outages by surveying 15 of the larger producers in the San Juan, Permian, Fort Worth, East Texas, and Gulf Coast Basins. These producers accounted for almost 40 percent of the total production for the five basins, with the highest percentages from the Fort Worth, San Juan, and Permian Basins.

For February 1 to February 5, an estimated 14.8 Bcf of production was lost from these five basins due to weather-related reasons. Of that amount, the surveyed producers lost 7.1 Bcf, equal to 48 percent of the total.

These production losses occurred for a variety of reasons. Some of the most common occurrences reported to the task force included:

- Freeze-offs (in some circumstances winterization was only designed for temperatures in the 20s),
- Icy roads that hampered logistics such as hauling away water produced by treatment equipment, and
- Rolling blackouts and customer curtailments.

Rolling blackouts were a problem particularly in the Fort Worth Basin, where they caused outages of compressors on gathering lines. In the Permian Basin, deployment of Load Resources by ERCOT during the event caused disruption to electric pumping units. According to information received from the

surveyed producers, 27 percent of the outages in the Fort Worth Basin were due to the rolling blackouts, and 29 percent of the outages in the Permian Basin were due to rolling blackouts or the curtailment of interruptible load.

The following table itemizes the reasons stated by these 15 producers for the supply shortfalls (the check marks indicate how many separate producers submitted information for each category):

	Permian	San Juan	Fort Worth	East Texas	Texas Gulf
Rolling Black Outs/ Curtailed Load	✓✓✓✓		✓✓		
Icy Roads	✓✓✓✓	✓	✓✓✓✓✓✓	✓✓	
Freezing of Compressors		✓✓	✓✓✓	✓✓	✓✓
Freezing Meters		✓			✓
Wellhead Freeze-offs	✓✓✓✓✓	✓✓	✓✓✓	✓✓✓✓✓	✓✓✓✓
Processing Facility Shut-in	✓	✓	✓	✓	
Ice Plugs in Gathering Lines	✓				
Frozen Salt Water Disposal Facilities	✓				

A basin-by-basin description of the gas production declines, and the resulting reduction in flows, follows.[216]

Permian Basin

The Permian Basin suffered production losses from February 1 through February 5 of 3.98 Bcf, with a maximum daily decline of 1.31 Bcf on February 4. The reasons provided for these declines are based on information received from

[216] The information is drawn from materials provided to the task force by producers and processing plants.

processors representing 34 percent of the maximum daily outage and producers representing 28 percent of the cumulative losses.

Reduced Flows at Processing Plant Pipeline Receipt Points

The task force reviewed receipt points on El Paso, Transwestern, Northern Natural Gas Company, and Enterprise Texas pipelines that had reductions exceeding 20,000 MMBtus per day, and thirteen processing plant points that had reductions of approximately 0.6 Bcf per day.

The receipt points on the El Paso pipeline with flow declines exceeding 20,000 MMBtus per day from February 1 to February 3 are all processing plant/gathering locations. They include Enterprise Waha (reduction of 120,681 MMBtus per day); Southern Union Jal#3 (reduction of 35,966 MMBtus per day); DCP Midstream GPS Eunice, reduction of 32,055 MMBtus per day; DCP Midstream Goldsmith Plant (reduction of 29,562 MMBtus per day); Southern Union Keystone (reduction of 28,515 MMBtus per day); Versado Gas Processors Texaco Eunice (reduction of 26,407 MMBtus per day); DCP Midstream Pegasus (reduction of 23,475 MMBtus per day); and Versado Gas Processors, Warren Monument (reduction of 21,460 MMBtus per day).

Transwestern's supply shortfalls in the Permian Basin were modest, relative to El Paso's, and were most significant at the Frontier Maljamar Gas Plant (reduction of 33,000 MMBtus per day) and at the Agave producer gathering connection (reduction of 44,000 MMBtu per day). Northern Natural processing plant receipt points with large reductions were the Atlas Midkiff Plant (reduction of 63,997 MMBtus per day) and the DCP Linam Ranch Plant (reductions of 106, 406 MMBtus per day). Finally, on Enterprise Texas Pipeline, the Crockett Gas Plant had a production shortfall of 34,376 MMBtus per day.[217]

Explanations varied for the reductions from the processing plants located in the Permian Basin.[218] The largest supply reduction to El Paso was the Enterprise Waha treating plant, which has a capacity of 280 MMcf per day. Enterprise reported that volumes delivered to the Waha Treating Plant decreased from 120 MMcf per day to approximately 40 MMcf per day, due to gas supply freeze-offs on February 2 and February 3. The plant's GE turbine then went down on

[217] Staff's analysis based on supporting data, display reports and data warehouse on file with Bentek (unpublished); *See also Market Alert: Deep Freeze Disrupts U.S. Gas, Power, Processing*, Bentek Energy LLC, Feb. 8, 2011, at 2-6.

[218] The task force received materials from a number of processing plants located in the basin. The material cited represents a sampling of data from those materials.

February 3, due to high discharge pressure when El Paso closed its valve at the plant tailgate (because of a high dew point in the gas stream).

On February 2, DCP's Linam Ranch plant in east New Mexico experienced freezing air ducts, resulting in a modest reduction to El Paso of 4,865 MMBtu per day from February 1 to February 3 (the reduction is 24,092 when measured from January 31). The plant then experienced a delay returning to service because of gas supply shortages from well freeze-offs, resulting in a lack of gas to restart the plant. The plant returned to normal operations on February 6 and supply returned to normal levels on February 7. Reductions in volume at three other DCP plants, Goldsmith, Pegasus, and Eunice, were the result of supply shortages from wellhead freeze-offs. Goldsmith and Pegasus experienced rolling blackouts that resulted in only brief outages, with gas being at the time either processed at the plants or delivered directly into pipelines.

Four DCP Texas processing plants were impacted by the rolling blackouts on February 2, but only one of them had resulting operational problems. The power outage caused the cooling water used for compression at the Roberts Ranch Plant in west Texas to freeze, leading to a plant shut down. (The plant was back in service on February 5.) The remaining plants did not experience any operational issues from the power outages. When the brief power outages occurred, the upstream gas bypassed the plants and was delivered without being processed.

Southern Union operates the Keystone and Jal #3 plants that together flowed reduced volumes of 64,481 MMBtu per day to El Paso. Southern Union reported that it experienced major property damage and significant financial losses due to freezing and failure of wells, pipes, and other facilities. The weather event ultimately resulted in the cessation of operations at many plants and field facilities, with corresponding reductions in deliveries to downstream pipelines. Some of Southern Union's issues were a direct result of rolling power outages at the Keystone facility at 7:25 AM and 9:05 AM on February 2, lasting 34 and 30 minutes, respectively.

Producer Declines in the Permian Basin

Producers representing a customary production level of approximately 0.75 Bcf per day[219] (approximately 30 percent of total basin production), reported production losses for the period February 1 through February 5 of 1.1 Bcf,

[219] This number represents the producers' usual production level, absent reductions experienced during the event.

estimated to be approximately 28 percent of the total basin production losses for the five days. The losses were attributed to the following:

- Power disruptions to electric motors on pumping units (29 percent of the total losses, or 0.32 Bcf),
- Icy roads,
- Ice plugs in gathering lines,
- Freeze-offs, and
- Downtime at processing plant.

Occidental Energy Marketing reports that on February 2, because of its status as a Load Resource on ERCOT's system, electric service to its production facilities were interrupted when ERCOT deployed it as a Load Resource. This interruption resulted in significant production losses. Power began to be restored approximately 1.5 hours after the disruption occurred.

ConocoPhillips Company reports that a significant percentage of its production losses in the Permian Basin were attributable to rolling blackouts that knocked out processing plants and pumps and lifts. The majority of its Permian Basin production comes from oil wells that rely on electric pumps and lifts to maintain oil flow. When the pumps failed, the natural reservoir pressures were unable to sustain flow, the oil congealed, and the wells and flow lines froze.

San Juan Basin

The San Juan Basin suffered production losses from February 1 through February 5 of 1.3 Bcf, with a maximum daily decline of 0.43 Bcf on February 3 and February 4. The reasons provided for these declines are based on information received from processors representing 52 percent of the maximum daily outage and producers representing 71 percent of the cumulative losses.

Reduced Flows at Processing Plant Pipeline Receipt Points

The task force reviewed receipt points on El Paso and Transwestern that had reductions exceeding 20,000 MMBtus per day, and eight processing plant receipt points with a reduction of approximately 0.35 Bcf per day (when netted against increased flows elsewhere).

Receipt points off of El Paso that had flow reductions exceeding 20,000 MMBtus per day are the BP Florida River Plant, with a reduction of 155,691 MMBtus per day, and two Williams Field Services processing plant/gathering locations; Milagro, with a reduction of 66,764 MMBtus per day, and #37, with a reduction of 24,047 MMBtus per day. Transwestern's most significant supply

shortfalls in the San Juan Basin for February 1 through February 3 were the William FS Kutz Plant, with reductions of 36,000 MMBtus per day, the Red Cedar Arkansas Loop gathering facility, with a reduction of 33,000 MMBtus per day, the Valverde Gas Plant, with a reduction of 48,000 MMBtus per day, and the Enterprise Chaco Plant, with a reduction of 87,000 MMBtus per day. These reductions were partially offset by increased flow of 100,000 MMBtus per day from the Williams FS Ignacio Plant.

Williams Fields Services reported that they had no operational problems, and the reduced volumes at Milagro and Kutz were due to upstream production shut-ins. With regard to the Chaco Plant, Enterprise reported it was operating at less than full capacity during the first week of February primarily because: (i) gas supplies were limited, (ii) ConocoPhillips moved approximately 100 MMcfd[220] from Chaco to their own San Juan processing plant on February 1, and (iii) winter production shut-ins occurred. In addition, the plant tripped on February 2 due to a hazardous gas supply alarm, and Enterprise's attempts to restart it were impeded by the combination of the lower volumes being nominated by producers and the cold weather experienced at the time.

Producer Declines in the San Juan Basin

Producers representing a customary production level of 2.0 Bcf per day (approximately 67 percent of total basin production), reported production losses for February 1 through February 5 of 0.9 Bcf, estimated to be approximately 71 percent of the total basin production losses for the five days.

None of the producers cited power outages as a cause of production losses. The losses were attributed to the following:

- Problems with compressor units,
- Freezing of wellhead meters,
- Cold weather, Freeze-offs,
- Icy roads, and
- Downtime at a processing plant.

Fort Worth Basin

The Fort Worth Basin suffered production losses from February 1 through February 5 of 4.7 Bcf and a maximum daily decline of 1.63 Bcf on February 6. The reasons provided for these declines are based on information received from

[220] MMcfd is a million cubic feet per day.

processors representing 11 percent of the maximum daily outage and producers representing 80 percent of the cumulative losses.

Reduced Flows at Processing Plant Pipeline Receipt Points

The Fort Worth Basin experienced supply reductions of almost 1.3 Bcf per day. Energy Transfer Fuel (ET Fuel) and Crosstex North Texas Pipeline (Crosstex) both receive gas from the Fort Worth Basin, and experienced reduced receipts.

ET Fuel had reduced receipts of 0.35 Bcf per day from January 31 through February 4. The largest reductions on the system occurred at the following receipt points: Chesapeake Energy production, with a reduction of 71,314 MMBtus per day; EOG Resources production, 127,418 MMBtus per day; Quicksilver Gathering, reduction of 69,675 MMBtus per day; and an ET Fuel processing plant, reduction of 61,668 MMBtu per day.[221]

Crosstex had a flow reduction estimated at 0.14 Bcf per day. The reduced volumes were due largely to the weather-related shut-down of the Silver Creek processing plant. Primarily due to freeze-offs, production at the plant declined by approximately 110,000 MMBtus per day from a normal flow rate of 185,000 MMBtus per day, to a five day average of 75,000 MMBtus per day on the outlet.

Atmos reported that intermittent supply reductions from nominated volumes were 0.13-0.17 Bcf per day.

The Energy Transfer Corporation Texas (ETC Texas) Godley area plant in north Texas experienced weather related difficulties on February 1 when one of its amine systems froze. ETC Texas was able to flow amine again on February 5. From February 1 through February 5, the inlet volume of the Godley Processing Plant decreased by 100 MMcfd, due to the loss of third party production from freeze-offs.

Producer Declines in the Fort Worth Basin

Producers representing a customary production level of 3.3 Bcf per day (approximately 69 percent of total basin production), reported production losses from February 1 through February 5 of 3.8 Bcf, estimated to be approximately 80

[221] Staff's analysis based on supporting data, display reports and data warehouse on file with Bentek (unpublished); pipeline scheduled volumes.

percent of the total basin production losses for the five days. The losses were attributed to the following:

- Rolling blackouts primarily affecting compressors on gathering lines (27 percent, or at least 1.0 Bcf),
- Icy roads, and
- Freeze-offs.

One large producer in the basin reported production losses for the period February 1 through February 5 as a result of electrical compression being shut down on a gathering system in the Dallas/Ft. Worth area. After power was restored, production was slow to return to standard rates. It therefore appears likely that a significant percentage of the lost production even after February 2 was due to the loss of power during the rolling blackouts.

East Texas

Producers representing a customary production level of 1.2 Bcf per day (approximately 24 percent of total basin production), reported production losses from February 1 through February 5 of 0.9 Bcf, estimated to be approximately 33 percent of the total basin production losses for the five days. The losses were attributed to the following:

- Equipment freeze-offs,
- Icy roads,
- Downtime at processing plants,
- Freezing of equipment, and
- Wellhead freeze-offs.

Gulf Coast

Producers representing customary production level of 0.7 Bcf per day from February 1 through February 5 (approximately 14 percent of total basin production), reported production losses from February 1 through February 5 of 0.36 Bcf, estimated to be approximately 18 percent of the total basin production losses for the five days. The losses were attributed to the following:

- Compressors freezing,
- Frozen meters, and
- Freeze-offs.

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VII. Prior Cold Weather Events

The arctic cold front that descended on the Southwest during the first week of February 2011 was indisputably severe. Many cities in Texas and New Mexico experienced a 50 degree drop in temperature over an eighteen-hour period. Temperatures dropped to the low teens in Texas and below zero in New Mexico. Much of north Texas experienced record setting sleet and snow, totaling up to seven inches. Exacerbating the effects of the cold temperatures were accompanying sustained winds of 30-40 mph, with gusts as high as 51 mph.

The 2011 winter weather event has been determined by at least one weather service to be a one in 10 year occurrence for some regions of Texas, in terms of low temperatures and duration.[222] Adding the sustained winds to these low temperatures, the resultant convective heat loss (wind speed plus ambient temperature) for some generators was estimated to approach a one in 25 year severity. Specifically in El Paso, only four prior recorded cold weather events approached 2011 in severity, making the storm the worst weather event in the El Paso area in 49 years.[223]

This cold weather event was thus unusual in terms of temperature, wind, and duration. It was not, however, entirely without precedent. The Southwest experienced other cold weather events in 1983, 1989, 2003, 2006, 2008, and 2010. In fact, two of those years, 1983 and 1989, had lower temperatures than 2011.[224] But only in l989 were the severity, geographical expanse, and duration of cold temperatures and high winds comparable to the February 2011 event.

In most of those prior years, utilities avoided any significant outages or curtailments. In other years, however, that was not the case. This section examines pertinent prior winter weather events to determine if there were lessons that could have been learned that might have prevented or ameliorated the service disruptions experienced in 2011.

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[222] Key Document, Severe Weather Readiness Workshop Formerly Generation Weatherization Workshop, Winter Weather Readiness for Texas Generators, (June 8, 2011), http://www.ercot.com/calendar/2011/06/20110608-OTHER (citing Weatherbank, Inc).

[223] Forensic Weather Consultants, LLC, Forensic Weather Investigation of the Weather Conditions and Air Temperatures for the Period 1911-2011 (100 Years) in El Paso, Texas, May 12, 2011, at 1.

[224] Based on data from the National Weather Service.

A. Electric

The two prior cold weather events of most significance for the ERCOT region occurred in 2003 and 1989; generators experienced weather-related outages in both of those years, and rolling blackouts were implemented in 1989. The winter of 1989 in particular resembles that of 2011, both in the severity of the weather and in loss of load.

These two events are described below, beginning with the most recent.

2003 Event

On Friday, February 21, 2003, weather forecasts predicted a cold front over a large part of Texas. The front moved in earlier and was more severe than projected. Statewide, temperatures ranged from 15 to 27 degrees below normal. On Monday, February 24, with freezing temperatures as far south as San Antonio, the demand for electricity reached 42,029 MW, exceeding ERCOT's forecast by 4218 MW, or 11 percent. Owners of gas-fired generating units were short on gas and tried to acquire more gas on the intraday market. At the same time, the demand for gas increased as a result of heating needs.

System Events

By 6:00 PM on February 24, ERCOT issued a Market Alert to increase available energy and capacity, and ordered all Reliability Must Run (RMR) units raised to maximum output levels. Temperatures remained below freezing in Austin and Dallas into Tuesday. By 7:30 AM on Tuesday, ERCOT issued a Market Advisory requesting more bids. At the same time, gas companies informed customers that they were activating tariff provisions to curtail gas for purposes other than "human need." At the request of three QSEs, the ERCOT Chief Operating Officer signed affidavits stating that gas needed for electric generation met the qualification of human need.

At 9:08 AM on February 25, gas curtailment to a power plant caused three units to trip, resulting in the loss of 745 MW of generation. System frequency dropped to 59.81 Hz and could not be restored. The ERCOT system control error (SCE) was -1,500 MW and increasing. At 12:01 PM, ERCOT declared Emergency Electric Curtailment Plan (EECP) Step 1 (EECP was the predecessor to today's Emergency Energy Alerts). Step 1, invoked when reserves fall below 2300 MW, entailed instructing all available generation to come on line, and securing emergency power from neighboring electrical grids through the DC ties.

The EECP Step 1 succeeded in rebalancing the system within 30 minutes. Step 1 remained in effect for about seven hours and 30 minutes.[225]

Gas Supply Problems

Generator owners reported to the PUCT that they had problems acquiring natural gas to run their gas-fired units. Natural gas was suddenly in short supply, but equally significant was the fact that the structure of the natural gas market limited the way generators were able to respond to fuel shortages in real time. Specifically this involved the following:

- **Depleted reserves:** The amount of gas in storage declined rapidly starting in November 2002, faster than the usual drawdown over the winter period, dropping from a five year high to a five year low in just four months.

- **Timeline for gas nominations:** Natural gas trading closed for the weekend, meaning that fuel for Monday must be procured on Friday, thereby not allowing leeway for late changes in the forecast.

- **Fuel shortages and curtailments:** Delivery constraints reduced the fuel supply to some plants, forcing their electric generating capacities to be derated.

- **Lack of on-site storage:** Natural gas pipeline companies have the bulk of their storage underground, but most of the former vertically integrated electric utilities had their own gas storage facilities. Independent power producers generally do not have their own gas storage; in a deregulated environment, most believe it is uneconomical to maintain it.

In 2003, almost three-quarters of the installed electric generating capacity was fueled by natural gas. Of those units, 16 percent had dual fuel capability, the other fuel being oil. Many units switched from gas to oil on February 24 and February 25, but most had to be derated in the process, and some experienced operating problems. Of the total of 5500 MW of capacity that was lost due to gas curtailments, ERCOT estimated that only 3200 MW was regained on back-up fuel oil, yielding a net loss of 2300 MW.

[225] Prices spiked to $990 per MWh on February 24 and February 25, 2003, as the result of hockey stick bidding. For a discussion of this phenomenon, see the earlier section of this report entitled "The Event: Load Shed and Curtailments."

PUCT Recommendations

The Market Oversight Division of the PUCT investigated the 2003 cold weather event and issued a number of recommendations.[226] Notable among these are the following:

- Stricter enforcement of Resource Plan accuracy.
- Improved weather and electric demand forecasting.
- Consider providing financial incentives for fuel oil inventories to be maintained for use by dual fueled units.
- Curtailment prioritization – development of a joint curtailment methodology for natural gas and electricity production.
- ERCOT should communicate with both QSEs and Transmission / Distribution Service Providers in the future when the power system is under stress.

Consequences

Following the 2003 generating unit outages, ERCOT revised its Protocols to establish Resource Plan performance metrics. These were put in place in 2004. The February 2003 event ultimately became an impetus for the establishing of Emergency Interruptible Load Service in ERCOT.

1989 Event

Beginning on Thursday, December 21, 1989, an arctic air mass descended on Texas for three days, delivering some of the coldest temperatures ever recorded in the state over a one hundred year period. Temperatures bottomed out at 7 degrees in Houston, -1 in Dallas, and -7 in Abilene. As a result of the cold weather, the demand on the ERCOT power system peaked at 38,300 MW, an 11 percent increase over the previous winter's peak and 18 percent above the projected peak for the winter of 1989-1990. This load level was equivalent to 93 percent of the summer peak demand.[227]

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[226] Julie Gauldin, Richard Greffe, David Hurlbut & Danielle Jaussaud, Pub. Util. Comm'n of Tex., Market and Reliability Issues Related to the Extreme Weather Event on February 24-26, 2003, 29 (May 19, 2003), *available at* http://puc.state.tx.us/industry/electric/reports/ERCOT_annual_reports/special/weather_event.pdf (PUCT 2003 Report).

[227] Elec. Reliability Council of Texas, *ERCOT Emergency Operation: December 21-23, 1989* (Undated), at 5 (ERCOT Emergency Operation).

The high demand, combined with weather-related forced outages of generating units and the curtailment of natural gas fuel supplies, resulted in the need for ERCOT to shed firm load system-wide for the first time in its history or the history of its predecessor.[228] Although there were two subsequent years in which ERCOT shed load during hot weather spells,[229] the 1989 event remained the only cold weather-related load shed event until February 2011.[230]

The 1989 event predated deregulation of the electric utility business in Texas, which began in 2002. Utility companies were therefore still vertically integrated and owned and operated generation, transmission, and distribution in their franchise service territories.

System Events

On Wednesday, December 20, 1989, a severe cold weather alert was declared for north Texas, effective the following morning; by 6:00 PM on Thursday, all of ERCOT's territory had been placed under severe alert. The temperature was 21 degrees in Dallas and 41 in Houston at that time. Gas curtailments were experienced starting on December 21, and continued for several days thereafter. These resulted in a considerable number of generators switching to or increasing their mix of fuel oil.

On Friday, December 22, ERCOT was unable to maintain minimum required operating reserve levels, due to record-high loads and a large number of generating units being forced offline. The frequency dropped below 59.95 Hz at 8:30 AM, and ERCOT ordered the start up of all available units. Those local control centers experiencing generation deficiencies also shed interruptible loads and minimized their own internal loads such as mining operations and station

[228] ERCOT's predecessor was Texas Interconnected Systems, formed in 1941. *Id.* at 1.

[229] In May 2003, the loss of two nuclear-powered generating units tripped automatic UFLS relays, resulting in the shedding of 1549 MW of firm load; service was restored within three hours and 30 minutes. In April 2006, an early season heat wave and the loss of four generating units caused ERCOT to shed 1000 MW of firm load via rolling blackouts; service was restored within one hour and 45 minutes.

[230] For the Houston area, which was the hardest hit in Texas, it was the first shedding of firm load in the history of the Houston Lighting and Power Company, dating back to the energizing of its first lighting load in 1882. *See* Bill Beck, At Your Service: An Illustrated History of Houston Lighting & Power Company (Houston Lighting & Power Company, 1st ed.1990) at 409; *see also* A Brief history of CenterPoint Energy, 1880-1889, CenterPoint Energy, http://www.centerpointenergy.com/about/companyoverview/companyhistory/timeline/23b55aef7af66210VgnVCM10000026a10d0aRCRD/ (last visited Aug. 3, 2011.

lighting. Utilities made public appeals for customers to voluntarily reduce consumption.

At 10:00 AM on December 22, ERCOT's load peaked at 38,300 MW. At this point, the online generating capacity was 39,800 MW, or 1500 MW greater than the load. Within two hours, decreasing load and the restoration of some generating units that had been forced offline earlier succeeded in bringing reserves back up to acceptable levels. Thus, the record-setting peak load period was met without the need to shed firm load.

However, temperatures continued to drop overnight Friday into Saturday, December 23, when they reached minimums of -7, -1, and 7 degrees in Abilene, Dallas, and Houston, respectively, with wind chill factors down to -35 degrees.

Up until midnight Friday night, approximately 3000 MW of generation was offline due to weather-related problems. The system also suffered 1500 MW of capacity reduction on account of units switching from natural gas to fuel oil. Between midnight and 7:00 AM on the following morning, an additional 4700 MW of generation was forced offline due to weather-related problems. It was also difficult getting power from outside ERCOT. West Texas Utilities offered 220 MW of emergency power to Houston Lighting and Power Company (HL&P), to be delivered over the North Tie, but then had to withdraw the offer due to unspecified technical problems.

By 5:36 AM on Saturday, December 23, the frequency had again dropped below 59.95 Hz, and over the course of the next hour and a half it hovered between 59.79 and 59.92 Hz, indicating the system was in difficulty. Interruptible loads were shed during the early morning hours. At 7:49 AM, ERCOT directed the utilities that were generation deficient to shed firm load.

HL&P had already begun shedding firm load, and increased its load shed to 1000 MW. Lower Colorado River Authority and the City Public Service of San Antonio shed 60 and 150 MW of firm load, respectively.

This firm load shedding, combined with some internal and external power transfers, succeeded in restoring the frequency to 60 Hz, re-stabilizing the system. Around 10:20 AM, however, seven generating units producing a combined 1275 MW were all forced offline nearly simultaneously, causing the frequency to plummet to 59.65 Hz. ERCOT was then forced to invoke system-wide load shedding, beginning with 500 MW, allocated among the utilities. Within ten minutes, the frequency had recovered and the system was stable once again.

As the midday Saturday load declined (typical for a weekend midday), much of the firm load that had been shed was able to be restored within only 30 minutes. The load shed directive was terminated slightly more than two hours later, when reserves increased to acceptable levels.

Accounts vary regarding the amount of total firm load that was shed. The PUCT reported a total load shed of 1710 MW.[231]

Generation Outages, Derates and Failures to Start

The following table presents a summary of the causes of the outages, derates, and failures to start experienced in ERCOT during the 1989 cold weather event.

Number of Units	Capacity	Cause
34	11,623 MW	Frozen Instrumentation
6	1385 MW	Paralyzed or Dead Fish Clogging Water Intakes
9	1051 MW	Other, Cold Weather-related
7	1246 MW	Non-weather-related
56	**15,305 MW**	**Subtotal**
Not Available	1500 MW	Gas curtailment impact (oil burning derate)
56+	**16,805 MW**	**Total**

[231] *See* Pub. Util. Comm'n of Tex., Electric Utility Response to the Winter Freeze of December 21 to December 23, 1989 (Nov. 1990), at 14 (PUCT 1989 Report); ERCOT Emergency Operation at 6.

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Virtually all types of generating units encountered problems, whether viewed from the perspective of fuel type or unit type, suggesting that the problems could not be attributed to a particular fuel or unit design. The breakdown is as follows:

- Sorted by **Fuel Type:**
  - Coal: 8 units; 4669 MW
  - Natural Gas: 29 units; 3881 MW
  - Distillate Oil: 1 unit; 257 MW
  - Dual Fuel – Gas & Oil: 15 units; 4418 MW
  - Dual Fuel – Coal & Gas: 1 unit; 670 MW
  - Nuclear: 1 unit; 1250 MW *
  - Petroleum Coke: 1 unit; 160 MW

    *This unit was forced off line the previous weekend due to the failure of an expansion joint in a steam condenser. An attempt was made to start it up during the December 21-23 cold spell, but that failed due to equipment freeze-ups.

- Sorted by **Unit Type:**
  - Conventional Steam Turbine Generators: 32 units; 13,298 MW
  - Simple Cycle Gas Turbines: 7 units; 235 MW
  - Combined Cycle Units: 17 units; 1772 MW

PUCT Recommendations

The PUCT staff investigated the cold weather event of 1989 and issued a report the following year that evaluated the causes of the generator outages and made recommendations. Because the circumstances of the event, and the causes of the outages, are so similar to those of the 2011 event, it is worth reproducing those recommendations verbatim:[232]

- All utilities should ensure that they incorporate the lessons learned during December of 1989 into the design of new facilities in order to ensure their reliability in extreme weather conditions.

- All utilities should implement procedures requiring a timely annual (each Fall) review of unit equipment and procedures to ensure readiness for cold weather operations.

[232] PUCT 1989 Report at 7.

- All utilities should ensure that procedures are implemented to correct defective freeze protection equipment prior to the onset of cold weather.

- All utilities should maintain insulation integrity and heat tracing systems in proper working order. Generating unit control systems and equipment essential to cold weather operations should be included in a correctly managed preventive maintenance program.

- Additional training programs for plant personnel on the emergency cold weather procedures, including periodic drills, should be implemented by each responsible utility.

- PUC Engineering Staff should modify procedures for power plant CCN [Certificates of Convenience and Necessity] reviews to include a specific review for plant reliability under adverse weather conditions. Of special interest would be the selection of proper design temperature ranges for the power plant site.

The PUCT identified inoperative or inadequate heat tracing systems and inadequate insulation on instrumentation sensing lines as the most common technical equipment problems encountered during the freeze. (These problems also featured prominently in the failure of many generators during the February 2011 event.) Many of the PUCT's recommendations involve weatherization improvements it advised the generators to make, including ensuring the working operation of freeze protection equipment, insulation, and heat tracing systems; instituting preventative maintenance for cold weather equipment; and implementing adequate training for extreme conditions.

The report concluded that "the near complete loss of the ERCOT grid brings an awareness that, even in Texas, plant operators must prepare for cold weather emergencies...this awareness of and attention to cold weather problems must be continued."[233]

Comparison of 1989 and 2011 Events

A summary of the statistics for the 1989 event and the 2011 event show how similar they were. Weather conditions and system events for each year are set forth below.

[233] *Id.*

Comparison Table: Basic Information

	December 21-23, 1989	February 1-2, 2011
Min. Temps & Wind Chills in Dallas Area	Temperature: -1 degrees F Wind Chill: -12 degrees F	Temperature: 13 degrees F Wind Chill: -6 degrees F
Peak System Load	38,300 MW	56,334 MW
Net Generating Capacity Reduction	11,809 MW 31% of peak load	14,702 MW 26% of peak load
Gross Generating Capacity Reduction	56+ units 16,805 MW	193 units 29,729 MW
Firm Load Shed	1710 MW 4.5% of peak load	4900 MW 8.7% of peak load
Overall Duration of Firm Load Shedding	5 hours, 47 minutes	7 hours, 24 minutes

The following table compares the causes of the outages, derates, and failures to start for each year.

Comparison Table: Generator Problems

	December 21-23, 1989	February 1-2, 2011
Frozen Instrumentation	34 units 11,623 MW	61 units 13,924 MW
Fish Clogging Water Intakes	6 units 1385 MW	None reported
Other Cold Weather-related	9 units 1051 MW	54 units 6365 MW
Non-weather-related	7 units 1246 MW	63 units 7905 MW
Gas Curtailment Impact	No. of units not specified 1500 MW	15 units 1534 MW
Weather-related % of Gross Capacity Reduction in MW	**84 % ***	**68 % ***
Frozen Instr. % of Gross Capacity Reduction in MW	**69 %**	**47 %**

* Does not count gas curtailments as weather-related.

Despite the recommendations issued by the PUCT in its report on the 1989 event, the majority of the problems generators experienced in 2011 resulted from failures of the very same type of equipment that failed in the earlier event. And in many cases, these failures were experienced by the same generators. Of the over 56 units and 16,805 MW of generating capacity that became unavailable during the December 1989 event, 43 units (representing 13,606 MW of capacity) are still in service in 2011. And 26 of those units, representing 5654 MW of capacity, experienced problems again during the February 2011 cold weather event.

The failures of these repeating units alone eroded a large share of ERCOT's reserve margin going into the morning of February 2, 2011, putting the entire system in jeopardy. Weighing the shedding of 4000 MW of firm load in February 2011 against the 5654 MW of generation capacity that experienced problems in both the December 1989 and February 2011 events, it can be argued that had three-quarters of that capacity not failed again in 2011, the February 2011 blackouts would not have happened. [234]

In its 1989 report, the PUCT commented that "whether the corrective actions being implemented [by the generators in the wake of the event] are sufficient to prevent future freeze-off related power plant failures, only direct experience with another deep freeze will ascertain."[235] Texas has now had that second event, and the answer is clearly that the corrective actions were not adequate, or were not maintained. Generators were not required to institute cold weather preparedness, and efforts in that regard lapsed with the passage of time. It is also possible that new ownership or new plant personnel lacked the historical perspective to make these efforts a priority, at least in the absence of externally imposed requirements.

The task force considered whether cost alone could have been the driving factor in the failure to maintain adequate winterization, and believes it to be unlikely. Based on current industry data, the task force estimates that for conventional gas-fired units and combined cycle units, the capital cost of upgrading basic equipment such as insulation and heat tracing could range from $50,000 to $500,000, depending on the age and condition of the materials, the original design temperature of the unit, and any change in the design temperature.[236] (However, if significant plant components needed to be upgraded

[234] The number of units that tripped, had derates, or failed to start was much larger in 2011 than in 1989. This is primarily a matter of scale. The number of generating units in ERCOT increased from 323 in 1989 to 550 in 2011. However, the increase in the number of units does not correlate exactly with the increase in generating capacity from 54,000 MW to 84,400 MW (using full wind power nameplate capacity, i.e., not adjusted) because of the large increase in combined cycle natural-gas fired plants since 1989 and the introduction of wind power. Combined cycle plants have multiple, and smaller, generating units than conventional steam-turbine plants. Wind power installations vary widely in size from tens of megawatts to hundreds of megawatts, adding greatly to the unit count, but less so to the actual capacity. With so many more, and smaller, units on line in 2011, it is not surprising that the number of trips, derates, and failures to start were greater than in 1989.

[235] PUCT 1989 Report at 6.

[236] *See* Black and Veatch Corp., *Cold Weather Protection Assessment for El Paso Electric Company (Rev. 1)*, at 6-4 and 6-7. In the event an independent engineering analysis is commissioned, and based on current industry estimates, the costs for such an analysis for a gas-fired unit could range from $25,000 to $150,000, depending on the type of unit.

or replaced, the cost could be significantly higher. For instance, if cooling towers had freezing problems, the addition of a cooling tower bypass or variable speed tower fan motor might be needed; such costs could range from $150,000 to $500,000.[237])

Texas has recently enacted legislation to deal with the problem of inadequate winterization by generators. A bill was introduced in the Texas legislature following the February 2011 blackouts, with provisions directing the PUCT to prepare a weather emergency preparedness report, to review the emergency operations plans on file, and to recommend improvements to the plans to ensure electric service reliability. In introducing the bill, State Senator Glenn Hegar stated: "What I don't want, is another storm and another report someone puts on the shelf for 21 years and nobody looks at."[238]

After a Senate Committee hearing, the bill was amended and unanimously adopted by the Texas Senate.[239] The House unanimously passed the bill on May 23, and the bill was signed into law by Governor Richard Perry on June 17, 2011.

B. Natural Gas

Gas production suffered declines in each of the six prior years identified by the task force as having had severe cold weather, and in 1989 and 2003, the declines led to gas curtailments that caused outages or derates to a number of gas-fired electric generators. While some winterization has been put in place by producers and processing plants, production declines occur with each successive severe cold weather event, including the event of February 2011. It may well be that producers have limited market incentives to pay for more elaborate winterization, as they will likely lose less money from short periods of non-production than they would expend on preventing freeze-offs at each of the many wells a producer typically owns.

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[237] *Id.*

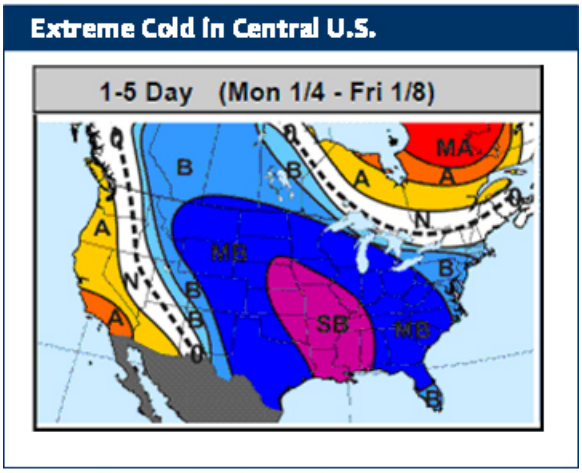
[238] Eric Dexheimer, *February Power Blackouts Across Texas echoed 1989 Failures, State Report Shows,* Austin American-Statesman, Apr. 10, 2011, http://www.statesman.com/news/local/ february-power-blackouts-across-texas-echoed-1989-failures-1390558.html?view AsSinglePage=true.

[239] SB 1133, 82 Leg., Reg. Sess. (TX 2011) *available at* http://www.capitol.state.tx.us/tlodocs/82R/billtext/pdf/SB01133E.pdf#navpanes=0. The bill would also allow the PUCT to require entities to update their emergency operations plans and to adopt rules relating to implementation of the bill.

Gas production declines in these prior extreme cold weather years are presented below, beginning with the most recent.

January 2010

In 2010, an ongoing cold spell led to wellhead and gathering line freeze-offs in the Rockies, San Juan and other southwestern producing basins. About 0.5 Bcfd[240] was lost in the Rockies and another 1.0 Bcfd was lost from the Southwest and shale basins. From January 21 through January 28, Northern Natural Gas and Southwest Gas issued low line pack alerts. High temperatures in every city in the area were above freezing during the month, and low temperatures fell only to the low 20s in a few cities on a few days.



[Color legend: N is normal, B is below normal, MB is much below normal, and SB is strong below normal.]

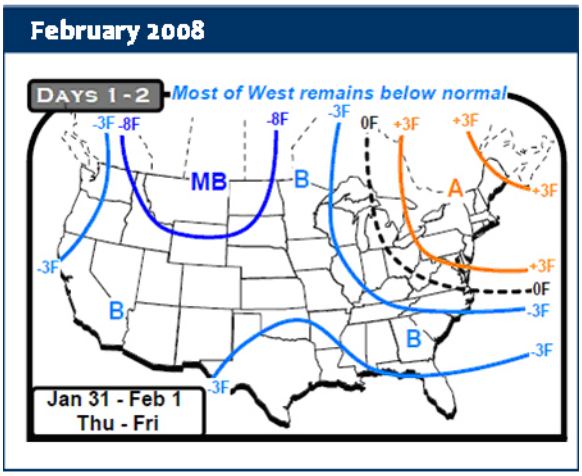
February 2008

There was widespread cold weather during late January and early February 2008 in the Rockies, Midwest, and Northeast. El Paso, Southwest Gas, Mississippi River Transmission (MRT), Natural Gas Pipeline Company of America (NGPL), ANR, Northern Natural Gas, and Kern River issued low line pack warnings, and receipts at the Opal[241] processing plant in Wyoming fell due to

[240] Production data in this section is drawn from Bentek, Supply and Demand Daily report.

[241] The Opal processing plant is a major source of output for Rockies production. Major interstate pipelines transport output from that plant to regional markets and markets in the East, the Pacific Northwest, California and the desert Southwest.

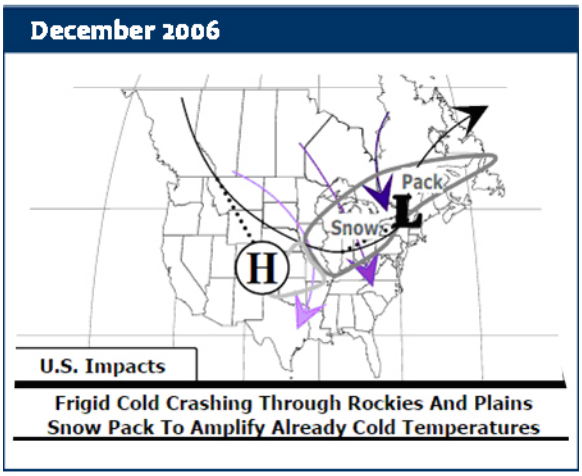
wellhead and gathering line freeze-offs in the region. Rockies production was off between 0.5 and 1.0 Bcfd over a 10-day period. Southwest regional production also fell by about 0.5 Bcfd during that time.



Source: MDA EarthSat, 1-5 Day Outlook, January 31, 2008

December 2006

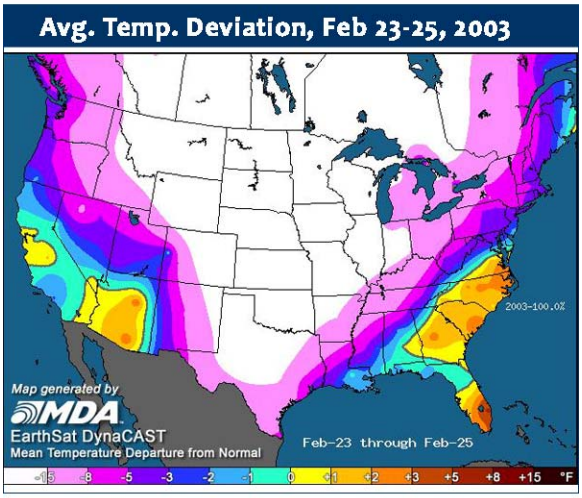
During the first few days of December 2006, unseasonably cold air accompanied by a good deal of snow covered much of the Rockies, the Great Plains and the Midwest. The Midwest and Chicago took the brunt of the frigid temperatures. Lows were in the single digits with a wind chill of -12 degrees. For two days, wellhead freeze-offs caused midcontinent production to fall almost 1 Bcfd, while Rockies and Texas/Louisiana production each were off about 0.5 Bcfd. Temperatures in Midland and El Paso dipped into the low teens for a short time. The short cold snap set off a flurry of operational warnings and alerts; El Paso issued a system operating condition flow order, and Southwest Gas, MRT, NGPL, Kern River, and Transwestern issued low line pack warnings.



Source: MDA EarthSat, Friday December 1, 2006.

February 2003

Overall, the winter of 2002/2003 was the third coldest of the most recent 11 winter periods. The winter began with record inventories (at that time) of gas in underground storage. But by April, over 2.5 Tcf (trillion cubic feet) was withdrawn, also a record at the time. Regional and national natural gas storage inventories were at record lows when compared to many metrics. During the period from February 23 through February 25, a shot of very cold air swept out of the Rockies and through the Midwest. It brought wind chills of -50˚ to portions of Wyoming and Colorado and lows below zero in Chicago. Gathering system and wellhead freeze-offs were reported in the Permian Basin and the midcontinent and Rockies regions, and NGPL issued an operational flow order. Midland and Dallas temperatures fell below freezing, although only for a short time. El Paso and Transwestern did issue low line pack alerts that were quickly lifted. As noted earlier, in ERCOT there were gas curtailments to electric generators, estimated by ERCOT to have resulted in a loss of 5500 MW of capacity.



Source: MDA EarthSat

In a May 19, 2003 report on the 2003 cold weather event, the PUCT observed that the gas supply shortages experienced by electric generators in Texas were due in part to an unusually steep decline in storage volumes in the months preceding the event. Those depleted storage reserves during a time of increased demand made it difficult for generators to obtain adequate gas supply, although only one supplier, the TXU Lone Star Pipeline (now Atmos Pipeline-Texas), actually curtailed industrial customers. The PUCT also noted that newly independent power producers, unlike the old vertically integrated utilities, tended not to have their own storage facilities, a factor that contributed to the supply shortage.[242]

[242] PUCT 2003 Report at 12-16.

The 2003 PUCT report recommended that the PUCT and the TRC collaborate on developing a joint curtailment methodology for natural gas and electricity.[243] According to industry observers at the time, the recommendation was aimed at coordinating electrical generation needs with gas supply, to ensure that supply was being used where it was most needed during shortages. However, the agencies reportedly were unable to develop a policy and the project died.[244]

December 1989

December 1989 was described at the time by the National Weather Service as the coldest December ever recorded for the combined northeast, central, and southeast regions of the United States. The freeze of December 21 through December 25 caused severe problems for Texas electric utilities, as described earlier in the discussion on electric prior cold weather events. Record and near record low temperatures occurred across the state. For Dallas, it was the coldest and second coldest days in the last 38 years; for Midland, the third and fifth coldest days; for San Antonio, the first and fourth. Houston and Brownsville each had two days among the top five coldest. Wind chill factors in Houston fell to -5 degrees, and in Dallas and Midland, to -12 degrees and -14 degrees, respectively.

While the gas supply situation was more precarious in the Northeast, the Gulf Coast supply regions, Texas and the Southwest were not without their problems. United States productive capacity had not been tested by a prolonged cold snap for more than a decade. Major processing plants[245], refineries and petrochemical plants in the Gulf Coast region shut down. Supply problems occurred in the Gulf of Mexico, Kansas, Texas, Oklahoma, Arkansas, and Louisiana. High winds prevented crews from reaching offshore production platforms that froze off. A major gathering operation in Oklahoma saw 40 percent of its supply frozen off. Producer respondents to a 1991 AGA study said that 10 percent of their production was affected by the cold temperatures.[246]

Most major interstate pipelines accessing Gulf supply experienced some kind of problem. Texas Eastern Transmission Corporation (TETCO) suspended all interruptible transportation deliveries and reduced firm deliveries by 0.5

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[243] *Id.* at 16.

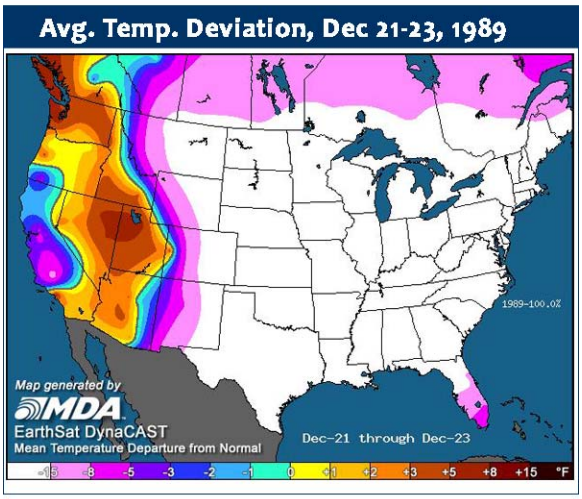
[244] Drawn from materials submitted to the task force by a pipeline company.

[245] Conoco Inc. lost its 1 Bcfd Grand Chenier processing plant in coastal Louisiana due to gas supply and plant operational problems.

[246] Foster Natural Gas Report No. 1845 (Oct. 3, 1991) at 20.

Bcfd.[247] Trunkline and NGPL also suspended interruptible transportation services. Transco curtailed firm service between 22 percent and 50 percent.[248]

In ERCOT there were gas curtailments to electric generators, tabulated earlier in the section on prior electric cold weather events.



Source: MDA EarthSat

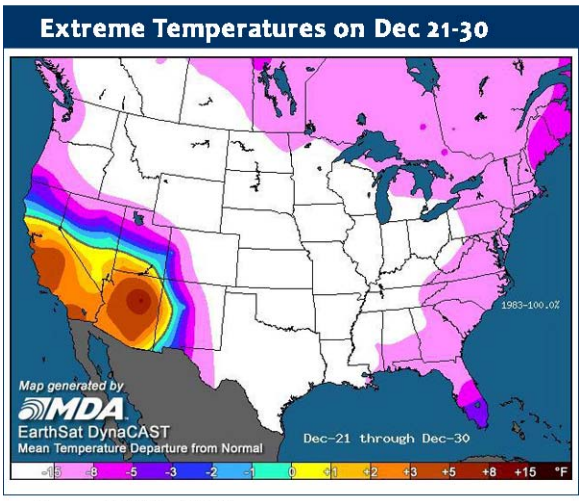
December 1983

At the end of December 1983, a nine-day stretch of cold weather in Texas resulted in a 3 Bcfd shortfall in supply. Demand was met by massive withdrawals from storage and fuel switching by generators. Refinery operable capacity fell over 72 percent during the week, due to gas supply curtailments. The TRC said that if schools and factories had not been closed for the Christmas holiday, deliveries to high priority customers would have been curtailed. Producers behind Valero Energy reported well freeze-offs, accounting for a 43 percent drop in supply.[249]

[247] TETCO reported a field supply shortfall of 1 Bcfd from its normal of 1.9 Bcfd.

[248] See Rick Hagar, Winter Hits U.S. Industry, Strains Gas Supply, OIL & GAS J., Jan. 1, 1990, at 28; see also Rick Hager, U.S. Gas Industry Ponders Lessons Learned from Severe Winter, OIL & GAS J., Mar. 5, 1990, at 17.

[249] See Rick Hagar, TRC Chairman Downgrades Size of Gas Surplus in U.S., OIL & GAS J., Feb. 27, 1984, at 47.



Source: MDA EarthSat

An examination of these prior years reveals that production declines are common during cold weather events. However, only in limited circumstances did they lead to curtailment of natural gas customers, including curtailment of gas-fired electric generators.

The production declines raise the question as to why producers did not improve their winterization preparations to withstand these not uncommon cold snaps. The reason most likely comes to one of cost (as well as to the lack of regulation requiring it). A study performed for the task force by the Gas Technology Institute[250] has estimated that capital costs for winterization could vary from as little as $2,800 to more than $30,000 per well, depending on the degree of cold weather protection required and other variable factors such as gas flow rates, pressures, existing winterization, and the like. In addition to these capital costs, the cost of maintenance and operational supplies such as methanol (antifreeze) could add up to several thousand dollars per year for each well. (These costs include costs associated with protecting field processing, such as separating water from the gas, as well as the flow lines to the separating facilities.)[251] Since it is not uncommon for the larger producers to have hundreds of wells in a given basin, these costs would quickly mount up. Such costs need to be accounted for in some fashion if mandatory weatherization were to be considered by regulatory or legislative bodies (as would the costs that would be incurred by electric generators to meet comparable requirements.)

[250] This report is included as an appendix, entitled "GTI: Impact of Cold Weather on Gas Production."

[251] Kent F. Perry, Gas Technology Institute, *Impact of Cold Weather on Gas Production in the Texas and New Mexico Gas Production Regions of the United States During Early February, 2011* (June 2011) at 33.

Producers suggest that even improved winterization of the wells would not prevent a significant portion of production declines, since other problems, such as icy roads that prohibit hauling off water (which, if not done, shuts down the well), are also commonly encountered.

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VIII. Electric and Natural Gas Interdependencies

The February 2011 cold weather event highlights the interdependency of electricity and natural gas, an interdependency that has grown in recent years. Natural gas has become an increasingly popular fuel choice for electric generators. Concurrently, compressors used in the production and transportation of natural gas have come to rely increasingly on electricity for their power source, rather than natural gas.

The reason for the increased popularity of gas-fired electric generation is one of economics. Natural gas prices have fallen due to increased gas production, beginning in 2008 when producers developed the technology to drill the Barnett Shale. Just prior to 2008, average daily marketed production was about 55.5 Bcf per day. Spot prices at the Henry Hub during 2007 averaged almost $7.00 per MMBtu. Shale production accounted for perhaps five percent of total United States production, and offshore production comprised approximately 15 percent.

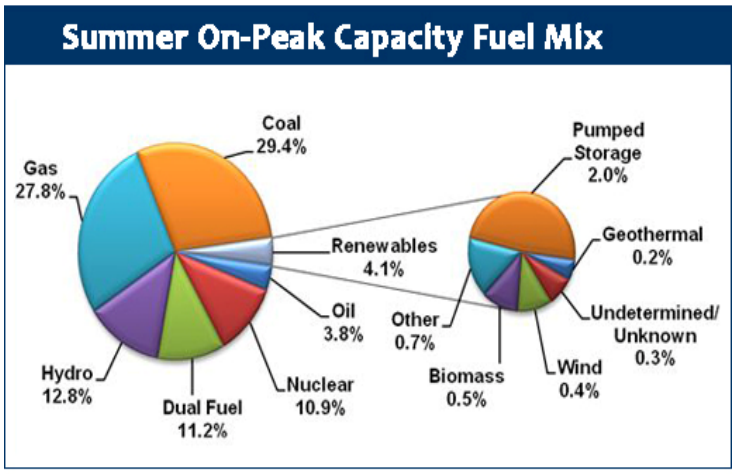
But by the end of 2008, average daily production had grown to over 59.3 Bcf per day. In the ensuing years, producers applied the lessons learned in the Barnett Shale to other basins, most notably the Fayetteville, Haynesville and Marcellus Shales, with notable results. Thus far in 2011, gas production is averaging almost 62.8 Bcf per day (and recently topped 64 Bcf per day), while average daily spot prices at the Henry Hub have fallen to $4.27 per MMBtu. Offshore production in 2010 accounted for only 10 percent of total United States production, and analysts estimate that shale production alone now accounts for 25 percent of total production.

At the same time, gathering companies, as well as pipelines and LDCs located in urban areas, have increasingly turned to electric-powered compressors. Gathering companies prefer electric-powered compressors because they can fit in smaller spaces than gas-fired compressors, and the companies do not need as much compressive power as the large pipelines. For pipelines and LDCs in urban areas, environmental restrictions relating to noise and air quality, as well as the ready availability of electricity, tip the scales in favor of electricity over natural gas. The large pipelines favor gas-fired compressors, because the gas is readily available to them and they have large horsepower demands.

The following chart depicts the mix of generation available for United States electricity needs in the summer of 2010, by fuel type.[252] It shows that 27.8

[252] NERC 2010 Summer Reliability Assessment (May 2010) at 10, http://www.nerc.com/files/2010%20Summer%20Reliability%20Assessment.pdf.

percent of all generation uses gas as the fuel source, and an additional 11.2 percent is dual-fueled (mostly gas and diesel oil).



Source: NERC's Summer Reliability Assessment, May 2010

The Southwest relies heavily on gas-fired generation to meet its peak capacity needs. In ERCOT, approximately 57 percent of the available on-peak summer and winter capability is from gas-fired generation (with 40 percent solely gas-fired and 17 percent having dual-fuel capability with gas as the primary fuel).[253] In the SPP region, 50 percent of the summer and winter on-peak capability is from gas-fired generation, and in WECC, 41 percent.

In New Mexico, gas-fired generating units consume approximately 70,102 MMcf annually, representing approximately one percent of total national consumption of gas used in the utility sector.[254] In Texas, gas-fired generating units consume approximately 1,387,421 MMcf of natural gas annually, representing approximately 20.2 percent of total national consumption of gas used in the utility sector.[255] And in Arizona, gas-fired generating units consume approximately 261,904 MMcf of natural gas annually, representing approximately 3.8 percent of total national consumption of gas used in the utility sector.[256]

[253] Based on data provided by ERCOT.

[254] EIA, Natural Gas Annual 2009, at 128-129 (Table 58), http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_annual/nga.html.

[255] *Id.* at 152-153 (Table 70).

[256] *Id.* at 70-71 (Table 29).

Interdependency Effects During the February Event

The task force examined data from numerous electric and gas entities to gauge the severity that shortfalls in one commodity had on the other during the February event. Materials received from natural gas producers indicate that the rolling blackouts (or customer curtailments) in ERCOT were a significant cause, from 29 to 27 percent respectively, of production shortfalls in the Permian and Fort Worth Basins. For pipelines and LDCs, however, the effects of the rolling blackouts were negligible.[257]

Gas shortfalls caused problems for some generators in Texas, although not nearly to the extent as did direct weather-related causes such as equipment failure from below-freezing temperatures. In ERCOT, as detailed in the section of this report entitled "Causes of the Outages and Supply Disruptions," the outages and derates from inadequate gas supply during the cold weather event totaled 1282 MW, compared to a peak net capacity reduction of 14,702 MW. While gas supply to SRP and EPE was compromised due to problems at the Chevron Keystone Storage Facility, EPE's generating units failed for other reasons, and SRP was able to obtain gas from other sources. However, during the 2003 cold weather event, there were significant gas curtailments to electric generators in Texas, which affected generating capacity. Gas curtailments also caused a loss of generating capacity in 1989, although to a lesser extent.

The task force was cognizant of the possibility that gas shortages may have been a less significant factor only because so many generators were forced offline for other reasons, and thus unable to take the gas (as was the case with EPE). The task force attempted to answer the question of whether there would have been adequate gas supplies to ERCOT had its failed gas-fired generators been able to take the gas. To do so, the task force tallied and compared the MWs forced offline, the amount of gas demand the generators would have imposed on suppliers had they been capable of running, and the capacity of the gas supply system at the time.

The task force determined that 5256 MW of generation in ERCOT could have imposed demands on the gas supply system had the generating units not experienced trips, derates, or failures to start. This number represents the total 5556 MW of the 55 gas-fired generating units in ERCOT, reduced by 300 MW for those generating units connected to a single pipeline that had pressure or gas

[257] An exception for LDCs supplying gas is the surge effect experienced when electricity is restored after an outage, which places instant and simultaneous demand on gas equipment and systems. This effect is described in the section of this report entitled "The Event: Outages and Curtailments."

quality problems (making it unlikely the generating units could have received gas even if they had had no operational difficulties). Each unit was assumed to have a 9,000 Btu/kWh heat rate. In the aggregate, these units would have added a maximum additional gas demand of approximately 1.1 Bcf per day.

Adding this additional hypothetical demand to the actual peak demand of 12.5 Bcf per day[258] would have imposed total demand on the system of 13.6 Bcf. Supply in January was running at 17.7 Bcf per day; these volumes declined during the first week of February. On February 2, the worst day from the standpoint of ERCOT, supply declined to 16.35 Bcf per day. On February 4, when production volumes hit their lowest point for the week, supply declined to 14.08 Bcf per day.

A comparison of these supply and demand numbers shows that total demand (actual demand plus hypothetical demand) would still have been below the available supply during the February cold weather event, particularly so on February 2, the day rolling blackouts were implemented. The task force's analysis therefore indicates there would have been adequate gas to supply the generators in ERCOT that failed for other reasons.[259] This conclusion was confirmed by knowledgeable industry observers, who were of the opinion that the Texas supply of gas would have been adequate had the generators not experienced weatherization problems.

Fuel Switching

A not insignificant amount of gas-fired generation in the Southwest has fuel switching capability. In ERCOT, 16 percent of total generation can fuel switch; in SPP, it is seven percent. Within WECC, of those generating units that are directly connected to El Paso, Northern Natural Gas, or ONEOK WesTex, 38 have fuel switching capability.

Fuel switching enables a simple or combined cycle generating turbine to alternate between fuel sources, typically natural gas and some type of fuel oil.

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[258] The actual demand listed is a worst case scenario, because the calculation was derived by adding together the peak demand of each of the three major pipelines in Texas serving gas-fired generating units. A more realistic number would probably be demand of approximately 12 Bcf per day or less.

[259] The excess gas was sold out of state, but had the generators in ERCOT been able to use it, they could have gotten it. Since gas prices rose modestly in the region during the event, the shippers would very likely have redirected the gas to Texas to take advantage of the higher prices, had the generators been able to accept it. This would be true whether or not the contracts were interruptible, since a shipper could adjust its purchases and sales to take advantage of the pricing differential.

Fuel switching can be as simple as a control room operator pushing a button which automatically switches to oil, or as complicated as having to remove gas injectors and install oil injectors in every position around the boiler, a process that can take days rather than minutes.

It is common for units that switch to an alternate fuel type to experience a capacity derate, since normally each unit is designed to most efficiently burn a particular fuel.

The choice to perform fuel switching is primarily based on three factors: 1) cost, 2) environmental restrictions, and 3) the availability of natural gas. Running the generating unit on alternate fuels, such as fuel oil, may cost up to twice as much on a MW basis.[260] And environmental and air quality control restrictions, which vary by state, may limit the number of hours per year a generator is allowed to run on fuel oil.

Fuel switching capability was a more desirable option in the past, when the relative prices of gas and oil fluctuated, making one or the other more economical at any given time. Given the decline in natural gas prices, this option has become less valuable.

During the February event, 20 generating units in ERCOT attempted to switch fuels, with 15 managing it successfully.[261] (This echoed ERCOT's experience during the 2003 cold weather event, when a number of units that attempted to switch fuels were unable to do so, and those that did switch experienced derates of capacity.[262]) SRP has nine units capable of switching, and EPE has three units capable of switching. None was asked to switch during the event, as the units either failed for other reasons or were able to obtain adequate gas supply. In SPP, of the three representative entities the task force examined, eight generating units have fuel switching capabilities; four attempted to switch during the event and ultimately succeeded, although half had initial difficulties.

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[260] Based on information supplied to the task force by an LDC.

[261] A majority of the units that attempted to switch fuels but were unable to do so experienced a mechanical failure of some sort in the switching equipment, which could have been due to the cold temperatures, inadequate maintenance, lack of regular testing, or the infrequent use of the alternate fuel in normal operations.

[262] PUCT 2003 Report at 17. The PUCT recommended that providing financial incentives for fuel oil inventories, to be maintained for use by dual-fueled generating units, should be considered.

Fuel switching raises a number of questions, such as: whether generators that have the capability to switch fuels should be required to maintain their alternate fuel equipment and stockpile an adequate supply of the alternate fuel, whether subsidies or incentives should be instituted to compensate for such requirements or to add fuel switching capabilities to those units that do not currently have it, and whether units that can switch fuels should be paid to do so in order to preserve gas supplies for residential consumers. These are issues that can be most fruitfully addressed in forums involving representatives of both the electric and natural gas industries operating in the region, as well as the regulatory bodies overseeing them.

Communications

In 2004, NERC released a report entitled "Gas/Electricity Interdependencies and Recommendations," which summarized the findings of its Gas/Electricity Interdependency Task Force (GEITF). The GEITF held a series of meetings with representatives of both the electric and gas industries and prepared a list of recommendations for NERC's consideration. The GEITF reported that a recurring theme expressed by gas industry participants was concern about communications between pipeline operators and entities other than the pipeline's contractual customers. While the pipelines communicate with the LDCs serving a generator or with the generator itself, they do not communicate with a regional reliability coordinator, apparently due to confidentiality restrictions. The GEITF recommended that NERC, in concert with other energy industry organizations, formalize communications between the electric industry and the gas transportation industry for the purposes of education, planning, and emergency response.

Communication failures between gas and electric entities did not seem to play a role during the February 2011 event (although there were complaints of communication issues between shippers and pipelines). Nonetheless, the electric and gas industries might consider revisiting the GEITF recommendations to see if procedures should be developed for communications between pipelines and reliability coordinators.[263]

[263] NERC plans to conduct an electric/gas interdependency study in 2011 to reevaluate the GEITF recommendations. The study will analyze whether procedures should be developed for communications between the electric and gas industries.

IX. Key Findings and Recommendations

The facts that came to light in the course of the joint inquiry conducted by the staffs of FERC and NERC, as well as the conclusions drawn from them, have been presented throughout the body of this report. Because the matters examined are complex and detailed, this section presents in summary form the task force's key findings. It also presents recommendations that the task force believes, if implemented, could significantly contribute to preventing a recurrence of the rolling blackouts and natural gas curtailments experienced in the Southwest during the February 2011 cold weather event.

A. The Electric Industry

Key Findings -- Electric

- During the February event, temperatures were considerably lower (15 degrees plus) than average winter temperatures, and represented the longest sustained cold spell in 25 years. Steady winds also accelerated equipment heat loss. However, such a cold spell was not unprecedented. The Southwest also experienced temperatures considerably below average, accompanied by generation outages, in December 1989. Less extreme cold weather events occurred in 2003 and 2010. Many generators failed to adequately apply and institutionalize knowledge and recommendations from previous severe winter weather events, especially as to winterization of generation and plant auxiliary equipment.

- While load forecasts fell short of actual load, the forecasts were not a factor in the loss of load. ERCOT manually increased its February 1 and February 2 forecasts by 4000 MW to factor in wind chill, and had established sufficient reserves to accommodate both forecasted load and the actual load that transpired. The reason blackouts had to be initiated was that over 29,000 MW of generation that was committed in the day-ahead market or held in reserve either tripped, was derated, or failed to start. This was the largest loss of generation in ERCOT's history, including during the prior cold weather load shed event in December 1989 and the two hot weather load shed events in 2003 and 2006. While units of all types (except nuclear generating units) tripped, derated, or failed to start in 2011, in ERCOT, gas combined cycle units had the highest percentage of failures, compared to their percentage of the total fuel mix.

- ERCOT and the generators within ERCOT could better coordinate generator scheduled outages, both in terms of the total amount of scheduled outages at a given time and their location. A substantial amount of generation (11,566 MW) was on scheduled outage going into the cold weather event. ERCOT's current Protocols provide that requests for scheduled outages submitted earlier than eight days before the outage is to begin are automatically approved, unless they would violate a Reliability Standard.

- ERCOT's fast action in initiating rolling blackouts prevented more widespread and less controlled ERCOT-wide blackouts. Had ERCOT not initiated manual load shedding, its under-frequency load shedding relays would have instantaneously dropped approximately 2600 MW (five percent of system load), a loss that could have created further system disturbances and resulting generation outages. Load shedding by the transmission and distribution operators in ERCOT's footprint was generally carried out in a timely and effective manner.

- Transmission operators and distribution providers generally did not identify natural gas facilities such as gathering facilities, processing plants or compressor stations as critical and essential loads.

- Balancing authorities, reliability coordinators and generators often lacked adequate knowledge of plant temperature design limits, and thus did not realize the extent to which generation would be lost when temperatures dropped.

- The lack of any state, regional or Reliability Standards that directly require generators to perform winterization left winter-readiness dependent on plant or corporate choices. While Reliability Standard EOP-001 R.4 and R.5 refer to winterization as a consideration in emergency plans, these requirements apply only to balancing authorities, transmission owners, and transmission operators.

- Generators were generally reactive as opposed to being proactive in their approach to winterization and preparedness. The single largest problem during the cold weather event was the freezing of instrumentation and equipment. Many generators failed to adequately prepare for winter, including the following: failed or inadequate heat traces, missing or inadequate wind breaks, inadequate insulation and lagging (metal covering for insulation), failure to have or to maintain heating elements and heat lamps in instrument cabinets, failure to train

operators and maintenance personnel on winter preparations, lack of fuel switching training and drills, and failure to ensure adequate fuel.

- Gas curtailment and gas pressure issues did not contribute significantly to the amount of unavailable generating capacity in ERCOT during the event. The outages, derates, and failures to start from inadequate fuel supply totaled 1282 MW from February 1 through February 5, as compared to an overall peak net generating capacity reduction of 14,702 MW.

Recommendations -- Electric

PLANNING AND RESERVES

1. Balancing Authorities, Reliability Coordinators, Transmission Operators and Generation Owner/Operators in ERCOT and in the southwest regions of WECC should consider preparation for the winter season as critical as preparation for the summer peak season.

The large number of generating units that failed to start, tripped offline or had to be derated during the February event demonstrates that the generators did not adequately anticipate the full impact of the extended cold weather and high winds. While plant personnel and system operators, in the main, performed admirably during the event, more thorough preparation for cold weather could have prevented many of the weather-related outages.

Capacity margins going into the winter of 2010/2011, for both ERCOT and the southwest regions of WECC, were adequate on paper. (ERCOT reported a 57 percent margin above forecasted winter peak demand, and the southwest regions of WECC projected a 105.7 percent margin.) But those margins did not take into account whether many of the units counted would be capable of running during the severe cold weather that materialized in February.

While the probability of a winter event in the predominantly summer peaking Southwest appears to be low, shedding load in the winter places lives and property at risk. The task force recommends that all entities responsible for the reliability of the bulk power system in the Southwest prepare for the winter season with the same sense of urgency and priority as they prepare for the summer peak season.

2. Planning authorities should augment their winter assessments with sensitivity studies incorporating the 2011 event to ensure there are sufficient generation and reserves in the operational time horizon.

Both ERCOT and the Southwest regions of WECC undertake planning studies to ensure that sufficient reserves are available to meet seasonal peak loads. However, the forecasted peak demand in the winter assessments for 2010/2011 was not as high as that actually experienced in early February.

Planners should undertake a sensitivity study, using the 2011 actual conditions as a possible extreme scenario, that reflects expected limits on available generation. These limits would include those due to planned outages, limited operations during periods of extreme cold weather, ambient temperature operating limitations, and any likely loss of fuel sources.

This sensitivity study should be used by operational planners to identify various system stress points, and by Reliability Coordinators, Balancing Authorities, and Transmission Operators to improve and refine strategies to preserve the reliability of the bulk power system during an extended cold weather event. These strategies should include procedures relating to utilization of generators with fuel switching capabilities and implementing early start-ups for generators with long start-up times.

3. Balancing Authorities and Reserve Sharing Groups should review the distribution of reserves to ensure that they are useable and deliverable during contingencies.

This recommendation is designed to ensure that Balancing Authorities take into account transmission constraints, other demands on reserve sharing resources, the possibility that more than one reserve sharing group member might experience simultaneous emergencies, and other factors that might affect the availability or deliverability of reserves. ERCOT is currently considering a similar recommendation, which was presented to its Board of Directors in March, 2011.

4. ERCOT should reconsider its protocol that requires it to approve outages if requested more than eight days before the outage, consider giving itself the authority to cancel outages previously scheduled, and expand its outage evaluation criteria.

ERCOT's Protocols provide that it may not forbid an outage request submitted more than eight days prior to the scheduled outage, unless the outage would keep ERCOT from meeting applicable Reliability Standards or Protocol requirements. The Protocols further limit review of outage requests made earlier

than eight days before the outage to the following three things: load forecast, other known outages of both generation and transmission, and the results of a contingency analysis to indicate whether the outages would cause overloads or voltage problems.

The task force recommends that ERCOT consider lengthening the period for which ERCOT may deny an outage request, assuming the conditions for doing so are met. (ERCOT is presently considering a Protocol revision to give itself the authority to deny an outage request that is not scheduled more than 90 days prior to the outage date, a revision which the task force supports.) In addition, ERCOT should consider giving itself the authority to cancel previously approved outages in cases of approaching extreme weather conditions, even up to the time of the event itself. In making this evaluation, ERCOT should take into account the costs that would be imposed on the generator as well as the practical difficulties of returning it to service if plant components are disassembled, as well as the generator's need to perform maintenance at some point while also avoiding the high demand summer season.

In addition to the criteria for outage evaluation currently provided in the Protocols, the task force recommends that ERCOT take into consideration the potential loss of units based on weather conditions beyond their design limits, and the effects likely to result from the totality of scheduled and proposed outages.

In furtherance of these criteria, ERCOT should:

- Have available to it the design temperatures of all generation resources.
- Take into consideration as an extreme weather event approaches which plants will not be available based on their design temperature limits.
- Consider increasing reserve levels during extreme weather events.
- Commit, for purposes of serving load and being counted as reserves, only those plants whose temperature design limits fall within the forecasted temperature range.
- Determine, prior to approving an outage, if the combination of previously approved scheduled outages with the proposed scheduled outages might cause reliability problems.

5. ERCOT should consider modifying its procedures to (i) allow it to significantly raise the 2300 MW responsive reserve requirement in extreme low temperatures, (ii) allow it to direct generating units to utilize pre-operational warming prior to anticipated severe cold weather, and (iii) allow

it to verify with each generating unit its preparedness for severe cold weather, including operating limits, potential fuel needs and fuel switching abilities.

ERCOT data on forced outages during the 50 coldest days between 2005-2011 show a correlation between low temperatures and forced outages. This was demonstrated not only by the February 2011 event but also by the 1989 event; in both cases, extremely low temperatures led to the loss of large amounts of generation and the implementation of rolling blackouts.

Increasing the amount of responsive reserves going into a cold weather event would compensate for the probability that a number of generating units might fail, and would provide better response to system instability in the event of such losses.

Additionally, pre-operational warming would help prevent freezing and identify other operational problems. Running a unit prior to the start of extreme cold weather would utilize the unit's own radiant heat to help prevent freezing. And starting it up would permit correction of any problems that otherwise would not be noticed until the unit was called upon for performance.

While pre-operational warming has considerable value, issues of whether or how generators are to be compensated for taking such actions at ERCOT's direction would need to be addressed.

COORDINATION WITH GENERATOR OWNERS/OPERATORS

6. Transmission Operators, Balancing Authorities, and Generation Owner/Operators should consider developing mechanisms to verify that units that have fuel switching capabilities can periodically demonstrate those capabilities.

Sixteen percent of ERCOT's generation capacity is listed as having fuel switching capabilities. During the February cold weather event, a quarter of the 20 units that attempted to switch fuel were unsuccessful. If a unit represents itself as having fuel switching capability, verification of the adequacy of its capability would provide useful information to the Balancing Authority or Transmission Operator as to the availability of that unit in the event of natural gas curtailments.

Fuel switching verification might consist of the following:

- Documented time required to switch equipment,
- Documented unit capacity while on alternate fuel,
- Operator training and experience,

- Fuel switching equipment problems, and
- Boiler and combustion control adjustments needed to operate on alternate fuel.

7. Balancing Authorities, Transmission Operators and Generator Owners/Operators should take the steps necessary to ensure that black start units can be utilized during adverse weather and emergency conditions.

The task force determined that a combination of scheduled and forced outages of ERCOT's black start units would have put ERCOT's ability to restore the system in jeopardy, had an uncontrolled blackout not been averted by the implementation of load shedding. Balancing Authorities and Transmission Operators should take steps to ensure the availability and reliability of their black start units during adverse weather and emergency conditions, particularly to prevent a gap in this function before 2013, when the provisions of Reliability Standard EOP-005-2 on System Restoration from Blackstart Resources becomes mandatory. These steps should ideally include auditing Generator Owner/Operators, random testing of black start units during temperature extremes (both hot and cold), determining the ambient operating temperature limitations of the black start units, evaluating the effects of extreme temperatures on implementation of the entity's black start plan; and ensuring that operators are trained to start the black start units during extreme weather conditions. ERCOT is presently considering Protocol revisions that would provide for unannounced testing of black start units and "claw back" payments for black start units that fail testing or fail to perform.

8. Balancing Authorities, Reliability Coordinators and Transmission Operators should require Generator Owner/Operators to provide accurate ambient temperature design specifications. Balancing Authorities, Reliability Coordinators and Transmission Operators should verify that temperature design limit information is kept current and should use this information to determine whether individual generating units will be available during extreme weather events.

In order to ascertain actual capabilities during extreme weather conditions, Balancing Authorities and Reliability Coordinators should require Generator Owner/Operators to provide accurate ambient temperature design operating limits for each generating unit that is included in its portfolio (including the accelerated cooling effect of wind), and update them as necessary. These limits should take into account all temperature-affected generator, turbine, and boiler equipment, and associated ancillary equipment and controls.

The Balancing Authorities should take steps to verify that Generator Owner/Operators comply with this requirement, and should prepare for the winter season by developing a catalog of individual generating unit temperature limitations. These should be used to determine if forecasted temperatures place a particular generating unit in a high risk category.

Lastly, Balancing Authorities and Reliability Coordinators should consider the feasibility of counting on a generating unit whose rating falls below forecasted weather conditions, and should consider whether to take into account weather-related design specifications in ranking units in the supply stack during critical weather events.

9. Transmission Operators and Balancing Authorities should obtain from Generator Owner/Operators their forecasts of real output capability in advance of an anticipated severe weather event; the forecasts should take into account both the temperature beyond which the availability of the generating unit cannot be assumed, and the potential for natural gas curtailments.

Balancing Authorities are permitted to request a forecast of real output capability under Reliability Standard TOP-002-02 R15. Doing so would allow operators to make proactive decisions prior to the onset of cold weather, including but not limited to:

- Requesting cancellation of planned outages,
- Directing advanced fuel switching,
- Directing startup of units with startup times greater than one day,
- Requesting startup of seasonally mothballed units, and
- Making advance requests for conservation.

In the case of ERCOT, which does not own the generators in its footprint, consideration needs to be given to ensuring that there is an adequate cost recovery mechanism in place for reliability measures taken by the generators at ERCOT's direction.

10. Balancing Authorities should plan ahead so that emergency enforcement discretion regarding emission limitations can be quickly implemented in the event of severe capacity shortages.

Some generators experienced derates during the event due to emission limitations. The Texas Commission on Environmental Quality (TCEQ) exercised enforcement discretion with respect to its emission restrictions during the event; however, this action, which was taken after the TCEQ received requests during the event itself, did not come in time to prevent all the emissions-related derates that

occurred on February 2. It is recommended that ERCOT work out procedures in advance with the TCEQ for the exercise of its enforcement discretion in the case of severe weather events, and have an internal procedure in place that delegates specific ERCOT personnel as responsible for contacting the TCEQ and other environmental regulatory bodies during the early stages of an event, in order to inform them of the significance of the situation.

WINTERIZATION

11. States in the Southwest should examine whether Generator/Operators ought to be required to submit winterization plans, and should consider enacting legislation where necessary and appropriate.

The task force determined during its inquiry that certain generators were better prepared than others to respond to the February cold weather event. In many cases the entities that performed well had emergency operations or winterization plans in place to provide direction to employees on how to keep their units operating. Although the implementation of a winterization plan cannot guarantee that a unit will not succumb to cold weather conditions, it can reduce the likelihood of unit trips, derates and failed starts.

The state of Texas has provided a starting point for such legislation with SB 1133, which was signed into law on June 17, 2011. This statute incorporates two important components: (1) mandatory reporting of emergency operations procedures, and (2) independent review by the PUCT.

In addition to the matters covered in the Texas statute, the task force recommends that planning take into account not only forecasts but also historical weather patterns, so that the required procedures accommodate unusually severe events. Statutes should ideally direct utility commissions to develop best winterization practices for its state, and make winterization plans mandatory. Lastly, it is recommended that legislatures consider granting utility commissions the authority to impose penalties for non-compliance, as well as to require senior management to acknowledgement that they have reviewed the winterization plans for their generating unit, that the plans are an accurate representation of the winterization work completed, and that they are appropriate for the unit in light of seasonal weather conditions.

NERC staff has concluded there would be a reliability benefit from amending the EOP Reliability Standards to require Generator Owner/Operators to develop, maintain, and implement plans to winterize plants and units prior to extreme cold weather, in order to maximize generator output and availability. Accordingly, NERC intends to submit a Standard Authorization Request, the first

step in the Reliability Standards development process, proposing modifications to the Reliability Standards for Emergency Preparedness and Operations.

Plant Design

12. Consideration should be given to designing all new generating plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available, factoring in accelerated heat loss due to wind speed.

The ideal time to prepare a generating unit to withstand cold temperatures is in the design stage. For that reason, the low temperatures and wind chills that can occur during the occasional severe storm should be incorporated in the design process.

13. The temperature design parameters of existing generating units should be assessed.

The task force found that for existing generating units, it is often not known with any specificity at what temperature the unit will be able to operate, or to what temperature heat tracing and insulation can prevent the water or moisture in its critical components from freezing. For that reason, Generator Owner/Operators should conduct engineering analyses to ascertain each unit's operating parameters, and then take appropriate steps to ensure that each unit will be able to achieve the optimum level of performance of which it is capable.

The task force recommends the following:

- Each Generator Owner/Operator should obtain or perform a comprehensive engineering analysis to identify potential freezing problems or other cold weather operational issues. The analysis should identify components/systems that have the potential to: initiate an automatic unit trip, prevent successful unit start-up, initiate automatic unit runback schemes and/or cause partial outages, adversely affect environmental controls that could cause full or partial outages, adversely affect the delivery of fuel to the units, or cause other operational problems such as slowed valve/damper operation.

- If a Generator Owner/Operator does not have accurate information about the ambient temperature to which an existing unit was designed, or if extensive modifications have been made since the unit was designed (including changes to plant site), it should obtain an engineering analysis

regarding the lowest ambient temperatures at which the unit can reliably operate (including wind chill considerations).

- Each Generator Owner/Operator should ensure that its heat tracing, insulation, lagging and wind breaks are designed to maintain water temperature (in those lines with standing water) at or above 40 degrees when ambient temperature, taking into account the accelerated heat loss due to wind, falls below freezing.

- Each Generator Owner/Operator should determine the duration that it can maintain water, air, or fluid systems above freezing when offline, and have contingency plans for periods of freezing temperatures exceeding this duration.

Maintenance/inspections generally

14. Generator Owner/Operators should ensure that adequate maintenance and inspection of its freeze protection elements be conducted on a timely and repetitive basis.

The task force found a number of inadequacies in generating units' preparations for winter performance. These included a lack of accountability and senior management review, lack of an adequate inspection and maintenance program, and failure to perform engineering analyses to determine the correct capability needed for their protection equipment.

The task force recommends the following:

- Each Generator Owner/Operator's senior management should establish policies that make winter preparation a priority each fall, establish personnel accountability and audit procedures, and reinforce the policies annually.

- Each Generator Owner/Operator should develop a winter preventative maintenance program for its freeze protection elements, which should specify inspection and testing intervals both before and during the winter. At the end of winter, an additional round of inspections and testing should be performed and an evaluation made of freeze protection performance, in order to identify potential improvements, required maintenance, and freeze protection component replacement for the following winter season.

- Each Generator Owner/Operator should prioritize repairs identified by the inspection and testing program, so that repairs necessary for

the proper functioning of freeze protection systems will be completed before the following winter.

- Each Generator Owner/Operator should use the recommended comprehensive engineering analysis, combined with previous lessons learned, to prepare and update a winter preparation checklist. Generator Owner/Operators should update checklists annually, using the previous winter's lessons learned and industry best practices.

Specific Freeze Protection Maintenance Items

The task force found that many generating units tripped, were derated, or failed to start as a result of problems associated with a failure to install and maintain adequate freeze protection systems and equipment. Based on these findings, on an examination of freeze protection systems of many of the affected generating units, and in some cases on standards issued by the Institute of Electrical and Electronics Engineers, the task force has prepared a number of recommendations designed to prevent a repeat of the spotty generator performance experienced during the February cold weather event. Of course, specific actions should conform to best industry practices at the time improvements are made, as well as to the requirements of any mandatory winterization standards imposed by regulatory or legislative bodies.

Heat tracing

15. Each Generator Owner/Operator should inspect and maintain its generating units' heat tracing equipment.

Specifically, the task force recommends:

- Each Generator Owner/Operator should, before each winter begins and before forecasted freezing weather, inspect the power supply to all heat trace circuits, including all breakers and fuses.

- Each Generator Owner/Operator should, before each winter begins and before forecasted freezing weather, inspect the continuity of all heat trace circuits, check the integrity of all connections in the heat trace circuits, and ensure that all insulation on heat traces is intact. This inspection should include checking for loose connections, broken wires, corrosion, and other damage to the integrity of electrical insulation which could cause grounds.

- Each Generator Owner/Operator should, before each winter begins, inspect, test, and maintain all heat trace controls or monitoring devices for proper

operation, including but not limited to thermostats, local and remote alarms, lights, and monitoring cabinet heaters.

- Each Generator Owner/Operator should, before each winter begins, test the amperage and voltage for its heat tracing circuits and calculate whether the circuits are producing the output specified in the design criteria, and maintain or repair the circuits as needed.

- Each Generator Owner/Operator should be aware of the intended useful life of its heat tracing equipment and should plan for its replacement in accordance with the manufacturer's recommendations.

Thermal Insulation

16. Each Generator Owner/Operator should inspect and maintain its units' thermal insulation.

Specifically, the task force recommends:

- Each Generator Owner/Operator should, before each winter begins, inspect all accessible thermal insulation and verify that there are no cuts, tears, or holes in the insulation, or evidence of degradation.

- Each Generator Owner/Operator should require visual inspection of thermal insulation for damage after repairs or maintenance have been conducted in the vicinity of the insulation.

- Each Generator Owner/Operator should ensure that valves and connections are insulated to the same temperature specifications as the piping connected to it.

- Each Generator Owner/Operator should be aware of the intended useful life of the insulation of water lines and should plan for its replacement in accordance with the manufacturer's recommendations.

Use of Wind breaks/enclosures

17. Each Generator Owner/Operator should plan on the erection of adequate wind breaks and enclosures, where needed.

Specifically, the task force recommends:

- A separate engineering assessment should be performed for each generating unit to determine the proper placement of temporary and/or permanent wind breaks or enclosures to protect and prevent freezing of critical and vulnerable elements during extreme weather.

- Temporary wind breaks should be designed to withstand high winds, and should be fabricated and installed before extreme weather begins.

- Generator Owner/Operators should take into account the fact that sustained winds and/or low temperatures can result in heat loss and freezing even in enclosed or semi-enclosed areas.

Training

18. Each Generator Owner/Operator should develop and annually conduct winter-specific and plant-specific operator awareness and maintenance training.

Operator training should include awareness of the capabilities and limitations of the freeze protection monitoring system, proper methods to check insulation integrity and the reliability and output of heat tracing, and prioritization of repair orders when problems are discovered.

Other Generator Owner/Operator Actions

19. Each Generator Owner/Operator should take steps to ensure that winterization supplies and equipment are in place before the winter season, that adequate staffing is in place for cold weather events, and that preventative action in anticipation of such events is taken in a timely manner.

Specifically, the task force recommends:

- Each Generator Owner/Operator should maintain a sufficient inventory of supplies at each generating unit necessary for extreme weather preparations and operations.

- Each Generator Owner/Operator should place thermometers in rooms containing equipment sensitive to cold and in freeze protection enclosures to ensure that temperature is being maintained above freezing and to determine the need for additional heaters or other freeze protection devices.

- During extreme cold weather events, each Generator Owner/Operator should schedule additional personnel for around-the-clock coverage.

- Each Generator Owner/Operator should evaluate whether it has sufficient electrical circuits and capacity to operate portable heaters, and perform preventive maintenance on all portable heaters prior to cold weather.

- Each Generator Owner/Operator should drain any non-critical service water lines in anticipation of severe cold weather.

Transmission Facilities

20. Transmission Operators should ensure that transmission facilities are capable of performing during cold weather conditions.

Transmission Operators reported several incidents of unplanned outages during the February 2011 event as a result of circuit breaker trips, transformer trips, and other transmission line issues. Although these outages did not generally contribute materially to any transmission limitations, some transmission breaker outages did lead to the loss of generating units. Many breaker trips were the result of low air in the breaker, low sulfur hexa-fluoride (SF_6) gas pressure, failed or inadequate heaters, bad contacts, and gas leaks.

Specifically, the task force recommends:

- Transmission Owner/Operators should ensure that the SF_6 gas in breakers and metering and other electrical equipment is at the correct pressure and temperature to operate safely during extreme cold, and also perform annual maintenance that tests SF_6 breaker heaters and supporting circuitry to assure that they are functional.

- Transmission Owner/Operators should maintain the operation of power transformers in cold temperatures by checking heaters in the control cabinets, verifying that main tank oil levels are appropriate for the actual oil temperature, checking bushing oil levels, and checking the nitrogen pressure if necessary.

- Transmission Owner/Operators should determine the ambient temperature to which their equipment, including fire protection systems, is protected (taking into account the accelerated cooling effect of wind), and ensure that temperature requirements are met during operations.

COMMUNICATIONS

21. Balancing Authorities should improve communications during extreme cold weather events with Transmission Owner/Operators, Distribution Providers, and other market participants.

During the February event, ERCOT communicated with Transmission Owners and Transmission Service Providers (an ERCOT-specific term) concerning the initiation of load shedding and the subsequent restoration of service. These communications appear to have been made in accordance with applicable ERCOT Operating Guidelines and Reliability Standards. However, ERCOT and several of its Transmission Service Providers that were responsible for curtailing firm load suggested areas for improvement in communications.

Transmission Service Providers are dependent on ERCOT for much of their information on ERCOT-wide system conditions, as they do not have information regarding generator trips beyond those on their own systems, and can only track ERCOT-wide system status by monitoring ERCOT's posted Physical Response Capability levels or monitoring frequency levels. Some of these Transmission Service Providers suggested that ERCOT should have communicated concerns about deteriorating conditions much earlier than it did.

A task force appointed by ERCOT's Board of Directors to look into the February 2 rolling blackouts concluded that there was a need for earlier dissemination of operational information to Transmission Service Providers and Distribution Service Providers (an ERCOT-specific term) during the period leading up to a possible emergency, a conclusion with which this task force agrees.

22. ERCOT should review and modify its Protocols as needed to give Transmission Service Providers and Distribution Service Providers in Texas access to information about loads on their systems that could be curtailed by ERCOT as Load Resources or as Emergency Interruptible Load Service.

Some ERCOT Transmission Service Providers expressed concern that they have virtually no information regarding loads on their own systems that may be deployed by ERCOT as Load Resources or Emergency Interruptible Load Service resources. These loads contract directly with ERCOT, and the Transmission Service Provider does not receive information about their status. When these loads are shed by ERCOT without prior notification to the Transmission Service Providers and Distribution Service Providers, they have the potential to cause localized imbalances in line flows, voltages, and other system parameters that may be problematic.

The task force suggests that ERCOT share information about the status of these loads with Transmission Service Providers on a daily basis, and study the effects of the loss of large blocks of these loads on the transmission grid.

23. WECC should review its Reliability Coordinator procedures for providing notice to Transmission Operators and Balancing Authorities when another Transmission Operator or Balancing Authority within WECC is experiencing a system emergency (or likely will experience a system emergency), and consider whether modification of those procedures is needed to expedite the notice process.

The Task Force observed a lag in communicating a declared system emergency in WECC. In one instance, a Reliability Coordinator did not issue an EEA 3 declaration until seven minutes after the decision had been made to do so; the delayed declaration appeared to have been the first official notice by the Reliability Coordinator to other WECC entities of the seriousness of the generation failures on the system of the Balancing Authority in question.

24. All Transmission Operators and Balancing Authorities should examine their emergency communications protocols or procedures to ensure that not too much responsibility is placed on a single system operator or on other key personnel during an emergency, and should consider developing single points of contact (persons who are not otherwise responsible for emergency operations) for communications during an emergency or likely emergency.

The task force's review of incidents during the event, as well as of operating procedures and protocols in place at the time, indicated that critical employees such as operators had numerous responsibilities that, while manageable in non-emergency situations, could prove impossible to meet during the often-compressed time frame of an emergency situation. In at least one instance, overloading a single on-call operations representative appears to have led to a delay in making emergency power purchases.

LOAD SHEDDING

25. Transmission Operators and Distribution Providers should conduct critical load review for gas production and transmission facilities, and determine the level of protection such facilities should be accorded in the event of system stress or load shedding.

Keeping gas production facilities in service is critical to maintaining an adequate supply of natural gas, particularly in the Southwest where there is a relatively small amount of underground gas storage. And keeping electric-

powered compressors running can be important in maintaining adequate pressure in gas transmission lines.

The task force suggests that a review of curtailment priorities be made, to consider whether gas production facilities should be treated as protected loads in the event of load shedding.

26. Transmission Operators should train operators in proper load shedding procedures and conduct periodic drills to maintain their load shedding skills.

The task force found that at least one Transmission Operator in WECC experienced a minor delay in initiating its load shedding sequence, due to problems notifying the concerned Distribution Provider. Another Transmission Operator experienced delay in executing its load shedding because the individual operators had never shed load before and had not had recent drills. These incidents underscore the necessity of adequate training in load shedding procedures.

B. The Natural Gas Industry

Key Findings -- Natural Gas

- Extreme low temperatures and winter storm conditions resulted in widespread wellhead, gathering system, and processing plant freeze-offs and hampered repair and restoration efforts, reducing the flow of gas in production basins in Texas and New Mexico by between 4 Bcf and 5 Bcf per day, or approximately 20 percent, a much greater extent than has occurred in the past.

- The prolonged cold caused production shortfalls in the San Juan and Permian Basins, the main supply areas for the LDCs that eventually curtailed service to customers in New Mexico, Arizona, and Texas.

- Wellhead freeze-offs normally occur several times a winter in the San Juan Basin but are not common in the Permian Basin, which is the supply source that LDCs in the Southwest region typically rely upon when cold weather threatens production in the San Juan Basin.

- Electrical outages contributed to the cold weather problems faced by gas producers, processors, and storage facilities in the Permian and Fort Worth Basins, with producers being more significantly affected by the blackouts; however, based on information obtained from a sampling of producers and

processing plants in the region, the task force concluded that the effect of electric blackouts on supply shortages was less important than the effect of freezing temperatures.

- Although producers in the New Mexico and Texas production areas implemented some winterization measures such as methanol injection, production was nevertheless severely affected by the unusually cold weather and icy road conditions, which prevented crews from responding to wells and equipment that were shut in.

- The extreme cold weather also created an unprecedented demand for gas, which further strained the ability of the LDCs and pipelines to maintain sufficient operating pressure.

- The combination of dramatically reduced supply and unprecedented high demand was the cause of most of the gas outages and shortages that occurred in the region.

- Low delivery pressures from the El Paso Natural Gas interstate pipeline, caused by supply shortages, contributed to gas outages in Arizona and southern New Mexico.

- Some local distribution systems were unable to deliver the unprecedented volume of gas demanded by residential customers.

- No evidence was found that interstate or intrastate pipeline design constraints, system limitations, or equipment failures contributed significantly to the gas outages.

- The pipeline network, both interstate and intrastate, showed good flexibility in adjusting flows to meet demand and compensate for supply shortfalls.

- Additional gas storage capacity in Arizona and New Mexico could have prevented many of the outages that occurred by making additional supply available during the periods of peak demand. Natural gas storage is a key component of the natural gas grid that helps maintain reliability of gas supplies during periods of high demand. Storage can help LDCs maintain adequate supply during periods of heavy demand by supplementing pipeline capacity, and can serve as backup supply in case of interruptions in wellhead production. Additional gas storage capacity in the downstream market areas closer to demand centers in Arizona and New Mexico could

have prevented most of the outages that occurred by making additional supply available in a more timely manner during peak demand periods.

Recommendations – Natural Gas

1. Lawmakers in Texas and New Mexico, working with their state regulators and all sectors of the natural gas industry, should determine whether production shortages during extreme cold weather events can be effectively and economically mitigated through the adoption of minimum, uniform standards for the winterization of natural gas production and processing facilities.

The Texas and New Mexico production basins experienced unusually sharp declines due to the prolonged freezing weather of early February 2011. Although these areas typically experience occasional freeze-offs during periods of sub-freezing weather, and although natural gas producers and processors in those regions employ some winterization techniques, to a significant degree those measures were inadequate to meet consumer demand during this event. Production difficulties were compounded by icy road conditions, which disrupted routine maintenance and delayed repairs.

Some industry representatives stated that producers and processors already have strong economic incentives to keep gas flowing at all times, and that increased winterization would not have prevented many of the shortfalls that occurred in the Southwest production basins in early February 2011. Others stated that the levels of winterization typically employed in these areas are designed to deal with less severe, more typical winter weather conditions, and that additional winterization could protect the system from the effects of unusually harsh weather. Many expressed the view that along with increased reliance upon natural gas for energy, steps should be taken to improve the reliability of gas supply during extreme cold weather events.

Whether the adoption of uniform winterization standards for natural gas facilities is the right way to meet the goal of increased reliability is a complex question. Among the issues that need to be resolved are the following:

- Determining the costs of increased winterization and balancing those costs against the need for increased reliability,
- Determining who should ultimately bear the costs of additional winterization, and whether ratemakers would be willing to pass the costs of increased reliability along to consumers,
- Determining whether it is practical to design for very low temperatures, which may not recur for years or even decades,

- Ensuring that standards are uniformly applied, and determining whether state commissions would have adequate resources or authority to promulgate and enforce those standards, and
- Identifying possible incentives for industry that could improve the reliability of winter supply without government regulation.

Because the Commission does not have jurisdictional authority over this sector of the natural gas industry for these purposes, we recommend that state lawmakers and regulators in Texas and New Mexico investigate whether minimum standards for the winterization of gas production and processing facilities should be adopted, by way of legislation, regulation, or the adoption of voluntary industry practices, and whether such standards would be likely to effectively and reliably improve supply during extreme weather events.

2. The gas and electric sectors should work with state regulatory authorities to determine whether critical natural gas facilities can be exempted from rolling blackouts.

The natural gas industry depends in many instances on electric utilities for the power that helps move gas from the production fields to end users. Electric-powered instrumentation, compression, pumps, and processing equipment are essential links in that process, and in some instances, even the brief, temporary loss of electric power can put a gas production, processing, compression, or storage facility out of service for long periods of time, especially where weather conditions delay access to those facilities. The resulting gas outages can contribute to electricity shortages by cutting off or reducing fuel supply to gas-fired generating plants.

Gas producers, processors, pipelines, storage providers, and LDCs should identify portions of their systems that are essential to the ongoing delivery of significant volumes of gas, and which are dependent upon purchased power to function reliably under emergency conditions. State regulatory authorities should work with the gas industry and electric transmission operators, balancing authorities and reliability coordinators to determine whether such facilities can be shielded from the effects of future rolling blackouts.

3. State utility commissions should work with LDCs to ensure that voluntary curtailment plans can reduce demand on the system as quickly and efficiently as possible when gas supplies are disrupted.

One tool available to LDCs faced with supply disruptions during periods of high consumer demand is the implementation of voluntary curtailment plans, which seek reductions or curtailment from large commercial users. State

regulators, who review and approve the voluntary curtailment plans of LDCs, should assess whether they are designed and implemented in a way that maximizes their potential effect in emergency situations.

Voluntary curtailment plans should include multiple points of contact for large customers and up to date, 24-hour contact information. Where appropriate, the plans should provide for pre-event planning, training, and customer education. Large customers should be contacted prior to emergencies and efforts should be made to explain the circumstances under which reductions or curtailments would be sought and to obtain advance commitments for possible reductions, giving LDCs a clearer idea of the amount of demand that can be reduced in an emergency. While voluntary curtailment does nothing to increase supply, in light of the importance of reducing demand when distribution systems are near collapse, regulators and the LDCs should ensure that planning for voluntary curtailments is as thorough and well-thought out as possible.

4. State utility commissions should work with balancing authorities, electrical generators, and LDCs to determine whether and under what circumstances residential gas customers should receive priority over electrical generating plants during a gas supply emergency.

Gas-fired generation provides much needed electrical power during a weather emergency, but also consumes large amounts of natural gas. Although restoring residential electricity service after a rolling blackout is a fairly simple process, restoring gas service after an outage is both labor-intensive and time-consuming.

State utility commissions should work with LDCs to identify situations where consumption by gas-fired generators could contribute to residential gas customer outages, and should consult with those generators and the relevant Balancing Authority to determine whether alternative power suppliers or fuel supplies could be used in emergency situations. The state commissions should also evaluate the relative importance, for human needs customers, of gas-fired generation and residential use, and should assess the relative impacts of curtailing generating plants versus gas supply to residences.

5. State utility commissions and LDCs should review the events of early February 2011 and determine whether distribution systems can be improved to increase flows during periods of high demand.

In some instances during the winter storm event, LDC distribution systems were unable to flow scheduled volumes, suggesting that downstream parties may not have had sufficient capacity or facilities to handle historically high demand.

Accordingly, state commissions and distribution companies should determine whether system enhancements can be made to improve volume handling capacity, such as additional distribution valving, looping, more compression, or reconfigured compression. Although such system improvements would probably not compensate for the level of supply shortfalls that occurred in early February 2011, they might allow LDCs to take higher volumes for longer periods of time.

6. State utility commissions should work with LDCs to determine whether the LDC distribution systems can be improved so that curtailments can be implemented, when necessary, in a way that improves the speed and efficiency of the restoration process.

The events of early February 2011 demonstrated that once operational pressures and line pack begin to fall beyond normal tolerances, little time may be available to evaluate, locate, and shut off portions of the pipeline systems of the LDCs to avoid system collapse. Regulators should work with LDCs, as part of the annual system review process, to determine whether the systems under their regulatory authority should be further sectionalized to provide more options when involuntary curtailments are necessary.

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ATTACHMENTS

Acronyms

Glossary

Appendices

Task Force Members

Legislative and Regulatory Responses by the States

Categories of NERC Registered Entities

Electricity: How it is Generated and Distributed

Power Plant Design for Ambient Weather Conditions

Impact of Wind Chill

Winterization for Generators

Natural Gas: Production and Distribution

Natural Gas Storage

Natural Gas Transportation Contracting Practices

GTI: Impact of Cold Weather on Gas Production

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Acronyms

AC	Alternating Current
ACE	Area Control Error
ANR	ANR Pipeline Company
Bcf	Billion Cubic Feet
Btu	British Thermal Unit
CFE	Comisión Federal de Electricidad
CNG	Compressed Natural Gas
COP	Current Operating Plan
DC	Direct Current
DC Tie	Direct Current Tie
EEA	Energy Emergency Alert
EILS	Emergency Interruptible Load Service
EPE	El Paso Electric Company
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
Hz	Hertz
IMM	Independent Market Monitor
ISO	Independent System Operator
LDC	Local Distribution Company
LNG	Liquefied Natural Gas
LRGV	Lower Rio Grande Valley
Mcf	Thousand Cubic Feet
MMcf	Million Cubic Feet
MW	Megawatt
MWh	Megawatt Hour
NGL	Natural Gas Liquids
NMGC	New Mexico Gas Company
NERC	North American Electric Reliability Corporation
OCN	Operating Condition Notice
OFO	Operational Flow Order
PNM	Public Service Company of New Mexico

Acronyms

PRC	Physical Response Capability
PUCT	Public Utilities Commission of Texas
QSE	Qualified Scheduling Entity
RMR	Reliability Must Run
SRP	Salt River Project Agricultural Improvement and Power District
SRSG	Southwest Reserve Sharing Group
RTO	Regional Transmission Organization
RUC	Reliability Unit Commitment
SCADA	Supervisory Control and Data Acquisition
SPP	Southwest Power Pool
SRSG	Southwest Reserve Sharing Group
TRE	Texas Reliability Entity, Inc.
TRC	Texas Railroad Commission
UFLS	Under-Frequency Load Shedding
WECC	Western Electricity Coordinating Council

Glossary

Active Power - Also known as real power, this is the rate at which work is performed or at which energy is transferred, usually expressed in kilowatts (kW) or megawatts (MW) when referring to electricity. In the field of electric power, the terms “active power” or “real power” are often used in place of the term “power” alone to differentiate it from reactive power. (See Reactive Power)

Allocation of Capacity - A process by which capacity available in a pipeline is distributed to parties in the event requests for volume (*i.e.*, nominations) are in excess of the available space. Typically the allocation is based on service type, contract type and a company's tariff provisions.

Alternating Current (AC) - Electric current that changes periodically in magnitude and direction with time. In power systems, the changes follow the pattern of a sine wave having a frequency of 60 cycles per second in North America. AC is also used to refer to voltage which follows a similar sine wave pattern.

Ambient Conditions - Common, prevailing, and uncontrolled atmospheric conditions at a particular location, either indoors or out. The term is often used to describe the temperature, humidity, and airflow or wind that equipment or systems are exposed to.

Ancillary Services - The services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system. These include, but are not limited to, voltage support, regulation, reserves, and black start capability.

Aquifer Storage - The storage of gas underground in porous and permeable rock stratum, the pore space of which was originally filled with water and in which the stored gas is confined by suitable structure, permeability barriers, and hydrostatic water pressure.

Area Control Error (ACE) - The instantaneous difference between a Balancing Authority’s net actual and scheduled interchange, plus the instantaneous difference between the interconnection’s actual frequency and scheduled frequency and a correction for meter error.

Asynchronous - In AC power systems, two systems are asynchronous if they are not operating at exactly the same frequency. Two systems may also be considered asynchronous if, at potential interconnection points, there is a significant difference in phase angle between their respective voltage waveforms.

Glossary

Auto-Transformer - A power transformer with a single coil for each electrical phase, as opposed to a conventional transformer, which has two coils per phase. In an auto-transformer, the entire coil acts as the primary winding while a portion of the same coil acts as the secondary winding.

Automatic Generation Control (AGC) - A feature of a power system's centralized control system that automatically adjusts generation in a Balancing Authority Area to maintain the Balancing Authority's interchange schedule plus its Frequency Bias.

Balancing (Natural Gas) - Equalizing a shipper's receipts and deliveries of gas on a transportation pipeline. Balancing may be accomplished daily, monthly or seasonally, with penalties generally assessed for excessive imbalances.

Balancing Authority (BA) - The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority area, and supports interconnection frequency in real time.

Base Load (Natural Gas) - A given volume of gas used by a LDC or other large user, remaining fairly constant over a period of time. Base load does not vary with heating degree-days.

Baseload Generating Units - Electric generating units which produce energy at a constant rate, usually at a low cost relative to other generating units available to the system. Baseload units are used to meet some or all of a given region's continuous energy demand on a seasonal or daily basis, including at minimum load levels, and tend to operate non-stop except for maintenance or forced outages.

Base Load Storage (Natural Gas) - Storage facilities capable of holding enough natural gas to satisfy long term seasonal demand requirements.

Blade - The component of a steam turbine that is acted upon by the flow of steam. Blades in steam turbines are also referred to as "buckets." Similarly, in gas, or combustion turbines, the blades are the components acted upon by the flow of the high pressure, high temperature gases produced in the combustor. In both steam turbines and combustion turbines, the blades are arranged in multiple stages of varying diameter, with many blades per stage. Modern wind turbines, in contrast, typically utilize only three long blades. The purpose of the blades is to extract energy from the motion of the propelling fluid (steam, combustion gases, or air) and convert it into rotational form by direct coupling to a common spinning shaft which is in turn used to drive a generator.

Glossary

Boiler - The component of a steam power plant in which water is heated and converted into steam.

British Thermal Unit (BTU) - the measurement of heat released by burning any material. The amount of energy necessary to raise the temperature of one pound of water by one degree Fahrenheit from 58.5 to 59.5 degrees Fahrenheit under standard pressure of 30 inches of mercury at or near its point of maximum density.

Bulk Electric System - The electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not considered to be part of the bulk electric system.

Capacitor Bank - A capacitor is a device that stores an electric charge. Although there is energy associated with the stored charge, it is negligible in terms of its capability to serve load. A capacitor bank is made of up of many individual capacitors. Its purpose is to provide reactive power to the system to help support system voltage by compensating for reactive power losses incurred in the delivery of power.

Capacity Market - A market where Load Serving Entities purchase generating capacity (including adequate reserves) to cover their peak loads.

Capacity Release (Natural Gas) - A mechanism by which holders of firm interstate transportation capacity can relinquish their rights to utilize the firm capacity to other parties that are interested in obtaining the right to use that capacity for a specific price, for a given period of time and under a specifically identified set of conditions. The firm transportation rights may include transmission capacity and/or storage capacity.

Capacity-Short Charge - In ERCOT, a monetary charge to Qualified Scheduling Entities (QSEs) who cannot meet their resource commitments when a Reliability Unit Commitment (RUC) study (conducted periodically) determines there is insufficient generation to meet projected demand, and the costs associated with bringing the needed additional generation on-line cannot be fully recovered using energy revenue. The capacity-short charge is the mechanism for covering those costs. This is done on the basis of settlement intervals.

Centrifugal Compressor Unit(s) -Compressors that produce pressure by centrifugal force from rotation of a compressor wheel that translates kinetic energy

into pressure energy of the gas. Centrifugal compressors are commonly used in gas transmission systems due to their flexibility.

Charge - In physics, charge, also known as electric charge, electrical charge, or electrostatic charge is a characteristic of an object that expresses the extent to which it has more or fewer electrons than protons. A single electron carries an elementary charge of negative polarity, whereas a single proton carries the same, except of positive polarity. The unit of electrical charge is the coulomb (symbolized C) where 1 C is equal to 6.24×10^{18} elementary charges. It is not unusual for real-world objects to hold charges of many coulombs. When two objects having electric charges are brought into proximity with each other, an electrostatic force is manifested between them – attractive if the charges are of opposite polarity and repulsive if the charges are of the same polarity.

Circuit Breaker - In electrical power systems, circuit breakers are used to disconnect and reconnect transmission lines, transformers, generators, and other facilities from the power system or from each other. Circuit breakers trip to interrupt the flow of current when faults develop, de-energizing the faulted facility and isolating it from the system. They are also used to switch facilities in or out of service.

Citygate - The point at which a Local Distribution Company receives natural gas from an interstate or intrastate pipeline.

Cold Load Pickup - Phenomenon that takes place when a distribution circuit is re-energized following an extended outage of that circuit. Cold load pickup is a composite of two conditions: 1) inrush current which reestablishes the magnetic fields in motors and transformers and the necessary temperatures in heating coils and incandescent lamp filaments and 2) loss of load diversity due to cyclic loads which normally cycle randomly with respect to one another, such as refrigerator compressors, all restarting at the same time. The inrush current may last up to several seconds while the loss of load diversity may persist for many minutes.

Combined Cycle Unit - This type of electric generating unit consists of one or more gas turbines, also referred to as combustion turbines, equipped with heat recovery steam generators to capture heat from their exhaust. Steam produced in the heat recovery steam generators then drives a steam turbine generator to produce additional electric power. A typical arrangement consists of two natural gas-fired combustion turbines combined with a single steam turbine, each driving its own electrical generator, for a total of three generators. The heat recovery aspect of combined cycle units increases the overall efficiency of electric power production.

Glossary

Comisión Federal de Electricidad (CFE) - A Mexican governmental entity that generates, transmits, distributes and sells electricity to more than 34.2 million customers, representing more than 100 million people annually. CFE interconnects to ERCOT via two high voltage DC (HVDC) ties and to WECC via AC transmission lines at the California border just south of San Diego.

Compressor or Compressor Units - Mechanical equipment that adds pressure to the natural gas stream to enable the flow of natural gas through a pipeline system.

Compressor Station - A permanent facility that houses compression equipment that supplies pressure to move natural gas through pipelines.

Condensate and Water Return Lines - Plumbing in a generating station that captures condensate and used water for recycling or re-use.

Condenser - In a steam turbine generating station, the condenser is a type of heat exchanger that cools the steam exiting the turbine to the point where it condenses into water, thereby recovering the high quality feed water for reuse. The cooling is accomplished using separate cooling water. Surface condensers use a shell and tube assembly wherein the cooling water is circulated in the tubes, and the steam and condensate are contained in the tank-like housing, or shell, that surrounds and encloses the tubes.

Conductor - In physical terms, any material, usually metallic, exhibiting a low resistance to the flow of electric current. A conductor is the opposite of an insulator. In electric power systems, the term conductor generally refers to the actual wires in overhead transmission and distribution lines, underground cables, and the metallic tubing used for busses in substations. Aluminum and copper are the predominant metals used for conductors in power systems.

Contingency - The unexpected and sudden failure or outage of a power system component, such as a generator, transmission line, transformer, or other electrical element.

Contingency Reserve Level - Contingency reserve is the provision of capacity deployed by a Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements. The Contingency Reserve Level is that level of reserves required for the reliable operation of an interconnected power system. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies. This

capacity is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment.

Contract Pressure (Natural Gas) - The maximum or minimum required operating pressure at a natural gas receipt or delivery point, as specified in the agreement between a pipeline and its customer.

Control Area - An electric power system or combination of electric power systems to which a common automatic control scheme is applied in order to: 1) match, at all times, the power output of the generators within the electric power system(s) with the load in the electric power system(s); 2) maintain scheduled interchange with other Control Areas; 3) maintain the frequency of the electric power system(s); and 4) provide sufficient generating capacity to maintain operating reserves, all within reasonable limits in accordance with Good Utility Practice.

Controllable Load Resources (CLR) - In ERCOT, CLRs are a type of load resource capable of controllably reducing or increasing consumption under dispatch control (similar to automatic generation control or AGC) and able to immediately respond proportionally to frequency changes (similar to generator governor action) to provide the following ancillary services: Up and Down Regulation (URS & DRS), Responsive Reserve (RRS), and Non-Spinning Reserve (NSRS).

Cooling Tower - A structure and associated equipment intended to facilitate the evaporative cooling of water by contact with air. In steam turbine generating stations, cooling water is routed through the cooling tower for cooling after having absorbed heat in the condenser.

Cooling Water - In steam turbine generating stations, water that is used in the condenser to extract heat from steam exiting the turbine for the purpose of condensing that steam back to feed water. The feed water is then cycled back through the boiler to make steam again. The cooling water is generally taken from a nearby lake (often man-made for this purpose) or river and is distinctly separate from the feed water that is used to make steam and which must be specially treated to prevent corrosion. Electric generating stations use wholly separate cooling water systems to extract heat from the large copper conductors comprising the generator stator windings.

Cooling Water Intakes - The point at which industrial plants, including power plants, bring cooling water into their system from lakes, rivers, or other sources.

Broadly, the total physical structure and any associated constructed waterways used to withdraw cooling water.

Current (Electric) - The rate of flow of electrons in an electrical conductor. The symbol for current is “I” and the unit is the ampere, or amp, where one amp is defined as one coulomb of charge per second.

Current Operating Plan (COP) - In ERCOT, a plan by a Qualified Scheduling Entity (QSE) reflecting anticipated operating conditions for each of the resources that it represents for each hour in the next seven operating days, including resource operational data, resource status, and ancillary service schedule.

Curtailment (Electric) - A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.

Curtailment (Natural Gas) - A method to balance a utility's natural gas requirements with its natural gas supply. Customers are typically ranked by priority in the utility’s curtailment plan. A customer may be required to partially cut back or totally eliminate its take of gas depending on the severity of the shortfall between gas supply and demand and the customer's priority.

Day-Ahead Market - A daily, co-optimized market in the 24 hour period before the start of the next operating day for ancillary service capacity, certain congestion revenue rights, and forward financial energy transactions.

Day-Ahead RUC (DRUC) - In ERCOT, a Reliability Unit Commitment (RUC) process performed for the next operating day.

Decommitment Payment - In ERCOT, a payment made to a resource committed by the Reliability Unit Commitment (RUC) process if the directive to use that resource is cancelled prior to its scheduled start time.

Demand (Electric) - The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts (kW) or megawatts (MW), at a given instant or averaged over any designated interval of time. The term “demand” is often used interchangeably with the term “load” with respect to electric power systems.

Depleted Oil and/or Gas Fields - Naturally occurring reservoirs that once held deposits of oil and gas, consisting of porous and permeable underground formations confined by impermeable rock or water barriers. The working gas requirement for this type of storage reservoir is generally about 50% of the total

reservoir capacity. Gas is typically withdrawn in the winter season and injected in the summer.

Derate (Electric Generator) - A reduction in a generating unit's net dependable capacity.

Direct Current (DC) - Electric current that is steady and does not change in either magnitude or direction with time. DC is also used to refer to voltage and, more generally, to smaller or special purpose power supply systems utilizing direct current either converted from AC, from a DC generator, from batteries, or from other sources such as solar cells.

Direct Current (DC) Tie - In electric power systems, the term "DC Tie" or, more correctly, "HVDC Tie" referring to high voltage DC, is used to describe a transmission-level facility that interconnects between two portions of a power system, two different power systems, or two different electric power interconnections. The DC Tie consists of: (1) a converter station to convert three phase AC power to DC; (2) a DC connection to a second converter station; and (3) a second converter station that reconverts the DC power back to three-phase AC. The DC connection between the two converter stations (step 2 above) may be either a long HVDC transmission line or, in the case of "back-to-back" converters at the same location, a simple set of bus bars. The power flow in DC ties is not free-flowing as it is in AC lines, but rather is controlled precisely by control systems on the converters. Unlike AC lines, DC ties can interconnect between asynchronous interconnections such as ERCOT, the Eastern Interconnection, and the Western Interconnection because concerns about frequency, phase angle, and voltage differences are rendered immaterial by the AC-to-DC-to-AC conversion process.

Distribution (Electric) - The function of distributing electric energy to retail customers, and all associated physical means of serving that function, including substations, low voltage distribution lines, transformers, etc.

Distribution Provider - As defined by NERC, a Registered Entity that provides and operates the "wires", *i.e.*, distribution lines, transformers, and associated facilities, between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider.

Distribution Service Provider - As defined by ERCOT, an entity that owns or operates a Distribution System for the delivery of energy from the ERCOT Transmission Grid to Customers.

Electrical Energy - Electric power generated, transmitted, distributed, and consumed over a period of time, expressed in kilowatt hours (kWh), megawatt hours (MWh), or gigawatt hours (GWh).

Electric Reliability Council of Texas, Inc. (ERCOT) - ERCOT is an Independent System Operator (ISO) that manages the flow of electric power to 23 million customers in Texas representing 85 percent of the state's electric load and 75 percent of its land area. ERCOT is registered with NERC to serve the following roles: Balancing Authority, Interchange Authority, Planning Authority, Reliability Coordinator, Resource Planner, and Transmission Service Provider. It is also jointly registered with other entities as a Transmission Operator**.**

Electric Reliability Organization (ERO) - The Energy Policy Act of 2005 required the creation of an independent Electric Reliability Organization (ERO) to be certified by FERC and tasked with developing and enforcing mandatory reliability standards applying to the bulk power system. (*See* Energy Policy Act of 2005, Pub. L. No. 109-58, section 102.)

Electromagnetic Induction - The creation of a voltage in a conductor due to a relative movement between the conductor and a magnetic field. Electromagnetic induction is the basic principle of operation of generators.

Emergency Interruptible Load Service (EILS) - In ERCOT, EILS is an emergency load reduction service designed to decrease the likelihood of the need for firm load shedding. It is provided by qualified loads that make themselves available for interruption in an electric grid emergency. Customers meeting EILS criteria may bid to provide the service through their Qualified Scheduling Entities (QSEs). EILS is called upon during an Energy Emergency Alert (EEA) Level 2B to assist in maintaining or restoring system frequency. EILS is not an Ancillary Service.

Energy - See Electrical Energy.

Energy Emergency Alert (EEA) - NERC Reliability Standard EOP-002-2.1 prescribes the use of an energy emergency alert (EEA) procedure when a load serving entity is unable to meet its customers' expected energy requirements. These energy emergencies are declared by the load serving entity's Reliability Coordinator, and are categorized by level of severity, *i.e.*, EEA1, 2, or 3, with level 3 being the most severe. ERCOT defines EEA as an orderly, predetermined procedure for maximizing use of available resources and, only if necessary, curtailing load during an emergency condition while providing for the maximum possible continuity of service and maintaining the integrity of the ERCOT system.

Energy Imbalance Service (EIS) - EIS is provided when a difference occurs between the scheduled and the actual delivery of energy to/from the transmission system over a single hour. The market participant must purchase this service from the transmission provider or make comparable alternate arrangements with another market participant who will purchase this service from the transmission provider.

Energy-only Market (Electric) - A market for electric energy that pays resources only for delivered energy and ancillary services, and does not pay for installed capacity (ICAP).

Energy-only Resource Adequacy Mechanism - A mechanism that allows real-time energy prices to rise in times of scarcity in order to provide incentives for investment in peaking as well as base-load generation.

E-Tag - Electronic Tagging, or e-Tag, is used to schedule an interchange transaction in a wholesale electricity markets. NERC and/or Regional Entities (such as WECC) collect all e-Tag data in near real-time to assist Reliability Coordinators in identifying transactions to be curtailed to relieve overload when transmission constraints occur. NERC defines an interchange transaction as "an agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority area boundaries."

Export - In electric power systems, exports refer to energy that is generated in one power system, or portion of a power system, and transmitted to, and consumed in, another.

Firm Service (Natural Gas) - Transportation service on a firm basis means that the service is not subject to a prior claim by another customer or another class of service and receives the same priority as any other class of firm service.

Flow Line - Flow lines carry the fluids or natural gas from the wellhead to and in-between individual vessels in separation, treating, heating, dehydrating, compression, pumping or other processing equipment generally located at or near the well site.

Force Majeure - A superior force, "act of God" or unexpected and disruptive event, which may serve to relieve a party from a contract or obligation.

Forced Outage - The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. This can be done automatically, as in the case of tripping, manually, as in the case of forced

shutdowns, or by withholding a generating unit, transmission line, or other equipment from returning to service due to unresolved problems.

Frequency - The rate, in terms of time, at which a periodic pattern repeats itself. In electric power systems, frequency is measured in cycles per second, or Hertz (Hz). The symbol is "F". The nominal, or base, frequency for power systems in North America is 60 Hz.

Frequency Bias - A weighting factor applied to the difference between the Interconnection's actual frequency and scheduled frequency during the calculation of a Balancing Authority's Area Control Error (ACE). The weighting factor determines how strongly a Balancing Authority will respond to deviations from the scheduled frequency. Larger Balancing Authorities will usually have a larger Frequency Bias.

Frequency Deviation - Broadly, a change in the frequency of an electrical interconnection. More typically, sudden changes that result in the frequency of the interconnection going outside the normal bounds of 59.95 Hz to 60.05 Hz due to the unexpected loss of a significant amount of generation or load.

Generation - The process of producing electrical energy from other sources of energy such as coal, natural gas, uranium, hydro power, wind, etc. More generally, generation can also refer to the amount of electric power produced, usually expressed in kilowatts (kW) or megawatts (MW) and/or the amount of electric energy produced, expressed in kilowatt hours (kWh) or megawatt hours (MWh).

Generator - Generally, a rotating electromagnetic machine used to convert mechanical power to electrical power. The large synchronous generators common in electric power systems also serve the function of voltage support and voltage regulation by supplying or withdrawing reactive power from the transmission system, as needed.

Generator Operator - An entity that operates a generating unit or a fleet of generating units and performs the functions of supplying energy and interconnected operations services to a power system.

Generator Owner - An entity that owns and maintains a generating unit or a fleet of generating units.

Generator Runback - The intentional rapid reduction of the output level of an electric generating unit or an entire generating station, either manually or

automatically via plant controls, due to any of a variety of problems in the plant that limit the plant's capacity to generate power, or problems on the transmission system external to the plant which limit the capability of the system to accept the plant's power output.

Good Utility Practice - Any of the practices, methods and acts engaged in or approved by a significant portion of the electric power industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Grid - An electrical transmission and/or distribution network. Broadly, an entire interconnection.

Heat Tracing - The application of a heat source to pipes, lines, and other equipment which, in order to function properly, must be kept from freezing. Heat tracing typically takes the form of a heating element running parallel with and in direct contact with piping.

Hertz - The unit of frequency equal to one cycle per second.

Hockey Stick Bidding - A pricing strategy during a supply shortage whereby a trader offers to sell a small quantity of energy at a price well above marginal cost, in order to manipulate prices upward.

Hourly RUC (HRUC) - In ERCOT, any Reliability Unit Commitment (RUC) executed after the Day-Ahead RUC (DRUC).

Human Needs Customers - Customers such as residential users, hospitals, and nursing homes, who use natural gas for essential human needs.

Hydrate Crystals - Crystals of hydrates formed under certain pressure and temperature conditions by hydrates and water present in natural gas. Hydrate crystals can form when the temperature is above the melting temperature of ice and can block natural gas wells, gathering systems, and pipelines.

Import Limit - The maximum level of electric power that can flow into a power system or portion of a power system over a transmission path or paths without

violating facility thermal ratings, voltage ratings, transient stability limits, or voltage stability limits either in real-time or post contingency, *i.e.*, after the loss of a generator, transmission line, or other facility.

Independent System Operator (ISO) - An organization responsible for the reliable operation of the power grid in a particular region and for providing open access transmission access to all market participants on a nondiscriminatory basis. ISOs in the U.S. include the California ISO, ISO New England, the New York ISO, PJM, the Midwest ISO, and ERCOT. These ISOs dispatch generation in their respective geographic territories.

Induction Machine - A rotating electromagnetic machine using alternating current that may be a generator or a motor. When a generator, the induction machine's rotor is driven at a speed greater than synchronous speed. When a motor, the induction machine's rotor is driven at a speed less than synchronous speed. Induction generators are rarely used for large scale power generation. Induction motors, on the other hand, are the most common type of AC motor. Induction machines absorb reactive power and cannot be used to produce reactive power (as a synchronous machine can).

Insulator - A material with a high resistance to the flow of electric current. More broadly, mechanical supports and spacers constructed of insulating materials. Electrically speaking, an insulator is the opposite of a conductor.

Interchange - Electrical energy transfers that cross Balancing Authority boundaries.

Interconnection - In North America, any one of the four major electric system networks – Eastern, Western, Quebec, and ERCOT. These operate asynchronously with respect to one another.

Interruptible Service - Service on an interruptible basis means that the capacity used to provide the service is subject to a prior claim by another customer or another class of service and receives a lower priority than such other classes of service.

Interruptible Responsive Reserve - In ERCOT, Interruptible Responsive Reserve is provided by load resources that are automatically interrupted when system frequency decreases to 59.7 Hz. The total amount of Interruptible Responsive Reserve procured for a given hour is limited to one half of the Responsive Reserve Service required for that hour.

Inverter - A converter designed and operated to convert DC power to AC power. In power systems, inverter generally refers to high voltage DC (HVDC) converters.

Island (Electrical) - An electrically isolated portion of an interconnection.. The frequency in an electrical island must be maintained by balancing generation and load in order to sustain operation. Islands are frequently formed after major disturbances wherein multiple transmission lines trip, or during restoration following a major disturbance.

Joule-Thomson Effect - The cooling that occurs when a compressed gas is allowed to expand in such a way that no external work is done. The effect is approximately 7 degrees Fahrenheit per 100 psi for natural gas.

Lateral Line - A pipe in a gas distribution or transmission system that branches away from the central and primary part of the system.

Line Pack - Natural gas occupying all pressurized sections of the pipeline network. Introduction of new gas at a receipt point "packs" or adds pressure to the line. Removal of gas at a delivery point lowers the pressure (unpacks the line).

Line Trip - This refers to the automatic disconnection of a transmission line by its circuit breakers. Line trips are initiated by protective relays and are designed to protect the power system when a short circuit, or fault, occurs on a line by isolating the faulted line from the system.

Liquefied Natural Gas (LNG) - Natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

Long Haul Pipeline - A transportation pipeline that transports natural gasa significant distance (hundreds of mile or more) from the production area.

Load - See Demand (Electric).

Load Acting as Resource (LaaR) - This term, discontinued by ERCOT when they transitioned from a Zonal Market to a Nodal Market on December 1, 2010, was replaced by the term Load Resource (see below).

Load Resource - In ERCOT, Load Resources provide ancillary services for either Responsive Reserve Service (RRS) or Non-Spinning Reserve Service (NSRS). There are two types of Load Resources – Controllable Load Resources (CLRs)

and Non-Controllable Load Resources (NCLRs). "Controllable" refers to the capability to control the load remotely from the ERCOT control center rather than solely at the end-use customer location (or by its Qualified Scheduling Entity (QSE)).

Load Service Entity - An entity that secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.

Load Shedding - The reduction of electrical system load or demand by interrupting the load flow to major customers and/or distribution circuits, normally in response to system or area capacity shortages or voltage control considerations. In cases of capacity shortages, load shedding is often performed on a rotating basis, systematically and in a predetermined sequence. (See Rolling Blackouts.)

Local Distribution Companies (LDC) - Any firm, other than a natural gas pipeline, engaged in the transportation or local distribution of natural gas and its sale to customers that consume the gas.

Magnetic Field - The invisible lines of force between the north and south poles of a magnet. A magnetic field is created when electric current flows through a conductor.

Make-Whole Charge - In ERCOT, a charge made to a Qualified Shedding Entity (QSE) for a resource to recapture all or part of the revenues received by a QSE that exceed the Make-Whole Payment for a resource (see below).

Make-Whole Payment - In ERCOT, a payment made to a Qualified Scheduling Entity (QSE) for a resource to reimburse it for allowable startup and minimum energy costs of a resource not recovered in energy revenue when a resource is committed by the Day-Ahead Market (DAM) or by a Reliability Unit Commitment (RUC).

Maximum Allowable Operating Pressure - The maximum operating pressure at which a pipeline system may be operated safely.

Mercaptans - A group of strong-smelling chemical compounds added to natural or LP gases as a safety measure, to warn of leaks.

Metering (Electric) - A meter is a device for measuring and displaying an electrical quantity. For example, meters are used to measure power flows, voltage, current, frequency, etc. The term "metering" generally refers to a group of meters

associated with a given facility, and the information from those meters transmitted to and displayed in a control room or control center.

Methanol - A light volatile flammable poisonous liquid alcohol used especially as a solvent, antifreeze, or denaturant for ethyl alcohol, and in the synthesis of other chemicals.

Nomination - A request for a physical quantity of natural gas under a specific purchase, sales or transportation agreement, or for all contracts at a specific point. A nomination will continue for specified number of days or until superseded by another service request for the same contract.

North American Energy Standards Board - A non-profit, private standards development organization established in January 2002 to develop voluntary standards and model business practices designed to promote more competitive and efficient natural gas and electric service.

Nodal Market (Electric) - Prices are assessed at points (*i.e.*, nodes) where electricity enters or leaves the grid. Transmission lines throughout the grid may be subject to congestion rents, which means generators may receive different prices based on how they contribute to or relieve congestion on the grid. ERCOT transitioned from a zonal to a nodal market on December 1, 2010. Their nodal market calculates transmission costs from the point of generation from roughly 4,000 delivery points. Nodal pricing is intended to provide a more detailed and accurate picture of transmission and generation than zonal pricing. ERCOT's nodal system reduces the time interval for which the market-clearing price is calculated to five minutes (from fifteen minutes in their former zonal market).

Non-Controllable Load Resources (NCLRs) - In ERCOT, these represent loads that provide selected Ancillary Services, but that do not have the capability of being switched or controlled directly from the EROCT control center. (Compare Controllable Load Resources)

Non-Spinning Reserve Service - In ERCOT, this refers to generation resources capable of being ramped to a specified output level within thirty minutes or load resources that are capable of being interrupted within thirty minutes. The generation resources must be capable of running at a specified output level for at least one hour, and the load resources must similarly be capable of remaining out of service for at least one hour.

Operating Condition Notice (OCN) - In ERCOT, this is the first of four possible levels of communication issued (by ERCOT) in anticipation of a possible emergency condition**.**

Operating Reserve - That capability above firm system demand required to provide for regulation, load forecasting error, forced and scheduled equipment outages, and local area protection. It consists of spinning and non-spinning reserve.

Operational Balancing Agreement - A contract that specifies the procedures that will be used between two interconnected natural gas pipelines in order to manage variances or imbalances at major interconnect points.

Operational Flow Order (OFO) - A notice to natural gas pipeline users designed to protect the operational integrity of the pipeline. OFOs require shippers to take action to balance their supply with their customers' usage on a daily basis within a specified tolerance band. Shippers may deliver additional supply or limit supply delivered to match usage.

Outage - The period during which a generating unit, transmission line, or other facility is out of service. Outages are typically categorized as forced, due to unanticipated problems that render a facility unable to perform its function and/or pose a risk to personnel or to the system, or scheduled / planned for the sake of maintenance, repairs, or upgrades.

Peak Load - As defined by NERC, the highest hourly integrated Net Energy For Load (generation plus imports minus exports) within a Balancing Authority area occurring within a given period (*e.g.*, day, month, season, or year), or the highest instantaneous demand within the Balancing Authority area.

Peak Load Storage (Natural Gas) - Storage that provides high-deliverability of gas supplies to the market over short periods of time.

Peaking Unit or Peaking Power Plant - Peaking plants operate primarily during times when load or demand increases rapidly to a maximum level and remains there for only a short time, *e.g.*, on hot summer afternoons when air conditioning causes electricity usage to reach its highest level in the daily cycle. Peaking plants are often powered by natural gas, but they can also be powered by water at hydroelectric dams or by fuel oil. These plants can be brought online and taken offline quickly, in response to changing demand.

Phase (Electrical) - In AC power systems, power is generated, transmitted, and distributed using three virtually identical sets of (1) coil windings in generators and transformers, (2) conductors in overhead and underground transmission and distribution lines and busses, (3) electrical poles and contacts in circuit breakers and switches and (4) other power equipment such as capacitor banks, reactors, etc., known as phases, and often identified by the letters A, B, and C. The three individual phase windings of a typical generator stator are arranged so that they're evenly spread out around the circular / cylindrical design/construction, each oriented one third of a turn apart (120 degrees) from the other two. As the rotor spins, its magnetic field sweeps through each of these windings sequentially as it completes a single rotation. The voltage, current, and power associated with each phase are therefore separated in time from the other two phases by virtue of this sequence. This method is much more efficient than a single phase approach not only for generating power, but also for its transmission and distribution.

Physical Responsive Capability (PRC) - In ERCOT, this is defined as the total amount of system wide On-Line capability that has a high probability of being able to quickly respond to system disturbances. It can be made up of generation and load resources.

Pigging - The practice of using pipeline inspection gauges or 'pigs' to perform various operations on a pipeline without stopping the flow of natural gas in the pipeline.

Planning Reserve Margin - Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand through the planning horizon, which can range from the upcoming season to a ten-year period. It is calculated as the difference between resources and peak demand, divided by peak demand to arrive at a percentage figure.

Poles - The opposite ends of a magnet where the field is most concentrated, designated as the north and south poles. In a synchronous generator, the magnetic poles are established by DC current passing through the field winding on the rotor which is essentially the coil of an electromagnet. Separately, in AC electrical equipment, particularly in switches and circuit breakers, poles refer to the contact assemblies associated with a particular phase. For example, it is common to refer to pole A, B, or C of a three phase disconnect switch. (See Phase)

Potomac Economics, Ltd. - The Independent Market Monitor (IMM) for ERCOT.

Power - In physics, power is defined as the rate at which energy is expended to do work. In the electric power industry, power is measured in watts (W), kilowatts (1 kW = 1,000 watts), megawatts (1 MW = 1 million watts), or gigawatts (1 GW = 1 billion watts). For reference, 1 kW = 1.342 horsepower (hp).

Power System - The collective name given to the elements of the electrical system. The power system includes the generation, transmission, distribution, substations, etc. The term power system may refer to one section of a large interconnected system or to the entire interconnected system.

Processing Plant - A surface installation designed to separate and recover natural gas liquids such as propane, butane, ethane, or natural gasoline from a stream of produced natural gas through the processes of condensation, absorption, adsorption, refrigeration, or other methods, and to control the quality of natural gas marketed or returned to oil or gas reservoirs for pressure maintenance, re-pressuring, or cycling.

Production Separator - An item of production equipment used to separate liquid components of the well stream from gaseous elements.

Qualified Scheduling Entity (QSE) - In ERCOT, a Market Participant that is qualified for communication with ERCOT for Resource Entities and Load Serving Entities (LSEs) and for settling payments and charges with ERCOT**.** QSEs submit schedules on behalf of Resource Entities or LSEs such as retail electric providers (REPs). QSEs must submit daily schedules for their bilateral transactions with total generation and demand and bid curves for zonal balancing up and balancing down energy. The schedules for generation and demand are required to be balanced so that supply equals demand. QSEs also bid for ancillary services.

Ramp or Ramp Rate (for Interchange Schedules) - The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period.

Ramp or Ramp Rate (for Generator Output) - The rate, expressed in megawatts per minute, that a generator changes its output, or is expected to change its output.

Rating - The operational limits of a transmission system element under a set of specified conditions**.** In power systems, equipment and facility power-handling ratings are usually expressed either in megawatts (MW) or in mega-volt-amperes (MVA). The term is also sometimes used to describe the output capability of generators.

Reactive Power - The portion of electricity that establishes and sustains the electric and magnetic fields of AC equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It is also needed to make up for the reactive losses incurred when power flows through transmission facilities. Reactive power is supplied primarily by generators, capacitor banks, and the natural capacitance of overhead transmission lines and underground cables (with cables contributing much more per mile than lines). It can also be supplied by static VAR converters (SVCs) and other similar equipment utilizing power electronics, as well as by synchronous condensers. Reactive power directly influences system voltage such that supplying additional reactive power increases the voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar), and is also known as "imaginary power."

Reciprocating Compressor Unit(s) - Also known as "positive displacement" compressors, reciprocating compressors operate by trapping a certain volume of natural gas within the compressor and reducing the volume. The high-pressure gas is then released through the discharge valve into the pipeline. Piston-operated reciprocating compressors fall within the category of positive displacement compressors. These compressors have a fixed volume and are able to produce high compression ratios.

Rectifier - A converter designed and operated to convert AC power to DC power. Electrically speaking, rectifiers are the opposite of inverters. High voltage DC (HVDC) converter stations contain large numbers of high power rectifiers.

Regional Entity - An independent, regional entity having delegated authority from NERC to propose and enforce Reliability Standards and to otherwise promote the effective and efficient administration of bulk power system reliability.

Regional Transmission Organization (RTO) - A voluntary organization of electric transmission owners, transmission users and other entities approved by FERC to efficiently coordinate electric transmission planning (and expansion), operation, and use on a regional (and interregional) basis. Operation of transmission facilities by the RTO must be performed on a non-discriminatory basis.

Regulation - The ability to maintain a quantity within acceptable limits. For example, frequency regulation is the control or regulation of the system frequency to within a tight bandwidth around 60 Hz. Voltage regulation is the control of a voltage level within a set bandwidth. In power systems operations, regulation often refers broadly to changing the output level of selected generators to match changes in system load.

Regulator, Pressure - A device that maintains the pressure in a fluid flow line, less than its inlet pressure within a constant band of pressures, regardless of the rate of flow in the line or the change in upstream pressure.

Relay Misoperation - Any unintentional operation of a protective relay when no fault or other abnormal condition has occurred.

Reliability Must Run (RMR) Unit - A unit that must run for operational or reliability reasons, regardless of economic considerations. ERCOT specifies that an RMR unit would not otherwise be operated unless it is necessary to provide voltage support, stability or management of localized transmission constraints under first contingency criteria where market solutions do not exist.

Reliability Unit Commitment (RUC) - In ERCOT, a process to ensure that adequate resource capacity and ancillary service capacity are committed in the proper locations to serve the forecasted load. ERCOT conducts at least one Day-Ahead RUC (DRUC) and at least one Hourly RUC (HRUC) before each hour of the operating day, but additional RUCs are conducted when needed to evaluate and resolve reliability issues.

Reserve Sharing Group - A group whose members consist of two or more balancing authorities that collectively maintain, allocate, and supply operating reserves required for each balancing authority's use in recovering from contingencies within the group.

Resource Entity (RE) - In ERCOT, Resource Entities either own or control a generation resource or behave as a load resource that can comply with ERCOT instructions to reduce electricity usage or provide an ancillary service. Each RE must also be represented by a Qualified Scheduling Entity (QSE), which establishes a control interface with ERCOT.

Responsive Reserve Services (RRS) - As defined by ERCOT, an ancillary service that provides operating reserves that is intended to: (1) arrest frequency decay within the first few seconds of a significant frequency deviation on the ERCOT transmission grid using primary frequency response and interruptible load, (2) help restore frequency to its scheduled value to return the system to normal, (3) provide energy or continued load interruption during the implementation of an Energy Emergency Alert (EEA), and (4) provide backup regulation. RRS can be provided by generation or by load resources having Interruptible Responsive Reserve capability.

Restoration - The process of returning generators and transmission system elements and restoring load following an outage on the electric system.

Reticulated Pipelines - Natural gas pipelines with highly networked, web-like transmission lines, with many possible transportation paths for natural gas supplies to reach the desired marketplace.

Rolling Blackouts - Also known as rotating outages, these are controlled, temporary interruptions of service to customers, most commonly initiated by switching off selected distribution circuits intended to reduce load during times of capacity shortfalls due to significant forced outages of generation and/or transmission facilities. The service interruptions are transferred from one group (or block) of customers to another over time so that no one group bears the entire burden of the necessary reduction in load.

Rotor - The rotating component of a generator attached to the spinning shaft of the generator. In the large synchronous generators that are predominant in electric power systems, the rotor winding acts as an electromagnet that produces the magnetic field used to induce voltage in the stator windings.

RUC Clawback Charge - In ERCOT, money returned by a Qualified Scheduling Entity (QSE) to ERCOT for a resource that was committed by the RUC process when the resource's start-up and minimum energy costs are lower than those allowed by the prevailing RUC guaranteed payment.

RUC Make-Whole Payment - In ERCOT, a payment made to a Qualified Scheduling Entity (QSE) for a resource that was committed by the RUC process when the resource's start-up and minimum energy costs are less than revenues received.

Salt Cavern - An underground natural gas storage cavern which has been developed in a salt dome by the solution mining process.

Scarcity Pricing Mechanism - A pricing mechanism based on the idea that under scarcity conditions, generating units will receive higher compensation for producing electricity. The additional revenue is intended to provide an incentive for investment in new generation facilities, and to promote overall system reliability. Under this mechanism, when available supply falls below a predetermined threshold, the price of additional power rises significantly.

Scheduled Frequency - For power systems in North America, the scheduled frequency is normally 60.00 Hz. During periods of time error correction, which

may last several hours, the scheduled frequency in a given interconnection is set to 59.98 Hz to slow down clocks that use synchronous motors when they are running fast, and to 60.02 Hz to speed them up when they are running slow The fact that the clocks are running fast or slow is an indication that system frequency averaged slightly higher or lower than 60.00 Hz over a long duration, signaling the need for a correction.

Sine Wave - The graphical representation of a mathematical function that describes the smooth, symmetrical, and periodic variation of a quantity that oscillates in magnitude or amplitude. In AC electric power systems, the voltage and current are characterized by sine waves having a frequency of 60 Hz. These waveforms, starting from a zero baseline, traverse a path that increases to a crest (positive maximum), then falls back to zero, continues downward to a trough (equal but opposite to the crest, *i.e.*, in the negative direction), and back to zero in one-sixtieth of a second.

Sluicing/Service Water Systems - A system used to remove bottom ash from many coal-fired boilers.

Southwest Power Pool (SPP) - A Regional Transmission Organization serving members in Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas (non-ERCOT). SPP is connected to and is part of the Eastern Interconnection.

Southwest Reserve Sharing Group (SRSG) - A pool of electric load-serving entities in Arizona, New Mexico, Nevada, southern California, and El Paso, Texas that have entered into an agreement to share contingency reserves. SRSG is a NERC Registered Entity that administers certain requirements on behalf of its members related to disturbance control and emergency operations. SRSG is connected to and is part of the Western Interconnection.

Spinning Reserve - Unloaded generation capacity that is synchronized and available to serve additional demand.

Stability - The ability of an electric power system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances. Instances of instability are serious because they have the potential to cause widespread outages in the power system, and possibly even in the entire interconnection.

Static VAR Converter / Compensator (SVC) - A combination of shunt reactors and shunt capacitors whose switching is precisely controlled by power electronics

to automatically manage reactive power injections and withdrawals from the power system to help maintain proper transmission voltage.

Stator - The stationary component of a motor or generator surrounding but not making physical contact with the spinning rotor in the typical cylindrical design/construction.

Substation - A site that houses circuit breakers, disconnect switches, transformers, reactors, capacitors, and other equipment serving as an electrical hub in the power system, especially at interfaces between different voltage levels. The prefix "sub" distinguishes substations from generating stations. A central control house is often provided to house control and protective equipment.

Supervisory Control and Data Acquisition Systems (SCADA) - A system of remote control and telemetry used to monitor and control a power system or a natural gas transportation or distribution system.

Synchronize - The process of bringing two electrical systems together by closing a circuit breaker at an interface point when the voltages and frequencies are properly aligned. Also, when generators are brought on-line, they are said to be synchronized to the system.

Synchronous - To be in-step with a reference. The rotor of a synchronous machine, be it a motor or a generator, spins in unison with the power system in terms of frequency (see Synchronous Speed, below).

Synchronous Speed - The speed at which the rotor of a synchronous generator must rotate in order to stay in synchronism with the rotating magnetic field of the system. The synchronous speed is determined by the frequency of the power system and the number of magnetic poles in the rotor. For example, the synchronous speed of a two pole steam-turbine generator in a 60 Hz system is 3600 revolutions per minute (rpm), while the synchronous speed of a 24 pole hydro generator is only one-twelfth of that, or 300 rpm.

System (Electric Power) - A combination of generation, transmission, and distribution facilities, equipment, and components.

System Operator - An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.

System Operating Limit (SOL) - The value of any of a number of electrical quantities such as real power flow (in MW), total power flow (real plus reactive) (in MVA), voltage (in kV), current (in amperes) or frequency (in Hz) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure that established reliability criteria are satisfied.

Telemetry - Equipment for measuring a quantity (amperes, volts, MW, etc.) and transmitting the result via a telecommunication system to a remote location for indication and/or recording.

Texas Reliability Entity (TRE) - Texas Reliability Entity, Inc. is authorized by NERC to develop, monitor, assess, and enforce compliance with NERC Reliability Standards within the geographic boundaries of the ERCOT region. In addition, TRE has been authorized by the Public Utility Commission of Texas (PUCT) and is permitted by NERC to investigate compliance with the ERCOT Protocols and Operating Guides. TRE is independent of all users, owners, and operators of the bulk power system.

Thermal Insulation - Any material which slows down or retards the flow or transfer of heat.

Transformer - A type of electrical equipment in the power system that operates on electromagnetic principles to increase (step up) or decrease (step down) voltage.

Transient Flow or Unsteady State Flow - The process which involves changes within the control volume with time.

Transmission - An interconnected group of lines and associated equipment operated at high voltage levels in the range of 100 kV to 765 kV in North America for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Transmission Operator - The entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.

Transmission Owner - The entity that owns and maintains transmission facilities, including, but not limited to, overhead and underground transmission lines, substations, transformers, circuit breakers, capacitor banks and busses.

Transmission Service Provider (TSP) - As defined by NERC, an entity that administers the transmission tariff and provides transmission service to transmission customers under applicable service agreements. ERCOT specifies that TSPs own or operate transmission facilities.

Treatment Plant - A plant designed primarily to remove undesirable impurities from natural gas to render the gas marketable. Examples of these impurities are water, water vapor, sulfur compounds, carbon dioxide, nitrogen and helium.

Turbine - A rotating mechanical device driven by the force of a working fluid. The working fluid is typically steam, water, combustion gases or, in the case of wind turbines, air.

Under Frequency Load Shedding (UFLS) - The automatic disconnection or tripping of customer load based on a decline in system frequency. The set points are predetermined. For example, a utility may trip 5% of their connected load if frequency falls below 59.3 Hz, an additional 10% if it falls below 58.9 Hz, and a final 10% if it falls below 58.5 Hz. The purpose of UFLS is to arrest the frequency decline accompanying major system disturbances generally involving the sudden loss of large amounts of generation or multiple transmission line tripping that results in the formation of an electrical island in which the remaining generation is inadequate to supply the load, thereby forestalling a complete system collapse.

Under Voltage Load Shedding (UVLS) - The tripping of customer load based on a decline in system voltage. For example, a utility may trip 5% of their connected load if voltage falls below 92% of nominal and an additional 10% of their load if voltage falls below 90% of nominal. The purpose of UVLS is typically to avoid a voltage collapse, but it can also be used to avoid overloading transmission facilities during contingency conditions when other transmission facilities trip or are forced out of service.

Unit Commitment - The process of selecting which generating units will be placed on line to serve the load and reserve requirements.

Verbal Dispatch Instruction - In ERCOT, a dispatch instruction issued by operators in the control center to a generating unit or units, load resource, or their Qualified Scheduling Entities (QSEs) orally over the telephone, as opposed to one issued in writing or issued automatically by a control system and delivered electronically via telecommunications.

Vertically Integrated Utility - An electric utility company or a federal, state, or municipal agency that owns and operates all aspects of the power system in its franchise service territory, *i.e.*, generation, transmission, and distribution. The ownership of certain facilities may be shared or held wholly by others, but the vertically integrated utility still controls the power system in the territory.

Voltage - The force characteristic of a separation of charge that causes electric current to flow. The symbol is "V" and units are volts or kilovolts (kV).

Well Freeze-offs - Natural gas flow blockages resulting from water vapor freezing or the formation of crystal hydrates in the gas stream.

Wellhead - The assembly of fittings, valves, and controls located at the surface and connected to the flow lines, tubing, and casing of the well so as to control the flow from the reservoir.

Wellhead Choke - Points at the wellhead where flow and pressure are primarily controlled.

Western Electricity Coordinating Council - The Regional Entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection.

Wheeling (Natural Gas) - The transportation of customer-owned gas by a transmission company for the customer at a pre-determined cost to the customer.

Windbreaks - Temporary or permanent structures intended to obstruct, or serve as a barrier against, the wind for the comfort and safety of people and/or the protection of property or equipment.

Wind Chill Factor - The term "Wind Chill Factor," is often used to explain the additional heat loss people experience through convection cooling when exposed to the wind. Whenever there is a temperature difference at a surface, *e.g.*, the difference between normal body temperature and ambient air at a lower temperature on the surface of human skin, heat is conducted across the surface from the warmer body to the cooler air. In the process, the layer of air on the surface is warmed and forms a thermal boundary which tends to slow the rate of heat loss. Wind accelerates the heat loss by literally sweeping away that boundary layer and replacing it, continuously, with air at the ambient temperature. This acceleration of heat loss caused by the wind makes people to feel that the air temperature is colder than it actually is. This feeling is quantified by assigning a

stationary air temperature, known as the Wind Chill Temperature, which yields an equivalent perception of cold.

Zonal Market - A market for electric energy divided into regional pricing zones. Generators within a zone receive the same price for the power they provide, and transmission lines crossing zonal boundaries are assessed additional costs due to market congestion when the power flowing through them reaches operational constraints.

Appendix: Task Force Members

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Appendix: Legislative and Regulatory Responses by the States

The natural gas and electricity shortages that occurred in the Southwest in early February 2011 seriously affected three states: Arizona, New Mexico and Texas.[1] Each state took different regulatory and legislative actions in response to the events. As part of its inquiry, the task force contacted state regulators and followed subsequent legislative and regulatory developments. The following section describes the actions taken by each state.

Arizona

In Arizona, approximately 19,000 customers in the Tucson and Sierra Vista areas lost gas service on February 3, 2011. Most of those customers had their service restored within four days.[2] The Arizona Corporation Commission (ACC), which among other things, regulates public utilities in the state, took the lead in reviewing the circumstances surrounding the gas outages.[3] One commissioner met with Southwest Gas Corporation representatives on February 3,[4] and another sent data requests to four impacted pipelines on February 16, 2011.[5]

On March 2, 2011 the ACC held an open meeting on the Southern Arizona gas outages, with witnesses from Southwest Gas Corporation and El Paso Natural Gas Company testifying. At the hearing, representatives from both companies stated that cold weather was the primary reason for the outage, as demand far outweighed supply during the record-low cold temperatures.

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[1] The task force contacted regulatory staff with the Public Service Commission of Nevada and the California Public Utilities Commission, who informed us that they did not experience a substantial, direct impact from the February 2011 gas supply shortages, and that no related inquiries or proceedings were underway in their states.

[2] *See* Alex Dalenberg, *ACC Meeting will Delve into SW Gas Outage, Arizona Daily Star* (Feb. 13, 2011).

[3] The Arizona legislature did not hold hearings or take any legislative actions in response to the outages.

[4] *See* Letter from Commissioner Barbara Burns to the Chairman and Commissioners of the Arizona Corporation Commission, Docket No. G-00000C-11-0081 (Feb. 11, 2011), *available at* http://images.edocket.azcc.gov/docketpdf/0000123284.pdf (last visited Aug. 5, 2011).

[5] *See* Letter from ACC Commissioner Sandra Kennedy to Southwest Gas Corporation; El Paso Natural Gas Company; UNS Gas, Inc.; and Transwestern Pipeline Company, LLC, Docket No. G-00000C-11-0081 (Feb. 7, 2011), *available at* http://images.edocket.azcc.gov/docketpdf/0000123172.pdf (last visited Aug. 5, 2011).

The ACC held two follow up meetings, on April 6, 2011 and April 7, 2011, to gather information from customers affected by the outages.[6] No further action has taken place in the ACC proceeding.

New Mexico

More than 30,000 customers lost gas service in New Mexico on February 2 and 3, 2011, some for as long as a week. Shortly thereafter, a New Mexico State Senator asked the state's Attorney General to look into the causes of the outages,[7] and the legislature announced that it would hold hearings. On February 11, 2011, a hearing was held before the full New Mexico Senate, which heard testimony from some of the individuals who lost gas service and from representatives of New Mexico Gas Company (NMGC), El Paso Natural Gas Company, and the New Mexico Public Regulation Commission (PRC).

On February 14, 2011, the New Mexico Senate directed the PRC to convene a task force to investigate how and why New Mexico consumers lost natural gas service and to make recommendations on how to prevent such loss of service in the future.[8]

On March 16, 2011, Governor Susana Martinez signed a bill[9] into law that created a state task force to investigate the causes of the outages and to make recommendations on how to prevent similar outages in the future.[10] As of the date of this report, the report from the Natural Gas Emergency Investigation Legislative Task Force is pending.

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[6] *See Tucson Residents Tell Commissioners About Freezing Nights and No Natural Gas Service, Associated Press*, (Apr. 8, 2011).

[7] *See State Senator Carlos Cisneros, Senator Calls on AG to Immediately Investigate Gas Outage* (Feb. 8, 2011), *available at* http://www.democracyfornewmexico.com/democracy_for_new_mexico/2011/02/sen-carlos-cisneros-requests-immediate-investigation-into-gas-outage-by-ag.html (last visited Aug. 5, 2011).

[8] SM 30 (Engrossed), 2011 Regular Session (NM, 2011), *available at* http://www.nmlegis.gov/Sessions/11%20Regular/final/SM030.pdf (last visited Aug. 5, 2011).

[9] HB 452 (Engrossed), 2011 Regular Session (NM, 2011), *available at* http://www.nmlegis.gov/Sessions/11%20Regular/final/HB0452.pdf (last visited Aug. 5, 2011).

[10] *See* House Executive Message No. 2 (Mar. 16, 2011) *available at* http://www.governor.state.nm.us/uploads/FileLinks/7bbb779a53dd4071933247333d38f22c/House%20Executive%20Message%202.pdf (last visited Aug. 5, 2011).

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The United States Senate Committee on Energy and Natural Resources held a field hearing in New Mexico on February 21, 2011 to receive testimony regarding the natural gas service disruptions in New Mexico and the reliability of regional energy infrastructure.[11] The Committee heard testimony from three different panels, and sent follow up questions to the Federal Energy Regulatory Commission.

The PRC opened its investigation into the outages on February 11, 2011.[12] In its order opening the inquiry, the PRC directed NMGC, Public Service Company of New Mexico, El Paso Electric Company, and Southwestern Public Service Company to provide testimony responding to specific questions within 30 days of the order.[13]

At the same time, the PRC also initiated a non-docketed proceeding entitled the NMPRC Informal Task Force Investigation into Severe Weather Cascading Events. The Informal Task Force, which included representatives of several New Mexico utilities,[14] PRC staff, the state Attorney General's Office, several municipalities, and the general public, was charged with developing a summary of the weather event, identifying the causes, determining how to mitigate the impact of future events, and reviewing the policies and rules of the PRC and other New Mexico agencies.[15]

On May 3, 4, and 5, 2011, the PRC held hearings on the outages, hearing testimony from gas company representatives and other parties, including

[11] *See* Recent Natural Gas Service Disruptions in New Mexico and Reliability of Regional Energy Infrastructure before the Senate Energy and Natural Resources Committee, 112th Congress (Feb. 21, 2011) *available at* http://energy.senate.gov/public/index.cfm?FuseAction=Hearings.Hearing&Hearing_ID=169bb12f-e360-3d3f-378c-4a762ddf0b56 (last visited Aug. 5, 2011).

[12] *See* Press Release, Public Regulation Commission, NMPRC initiates investigation into Natural Gas Delivery Failure (Feb. 10, 2011), *available at* http://www.nmprc.state.nm.us/news/pdf/2011-02-10-gasinvestigation.pdf (last visited Aug. 5, 2011).

[13] In the Matter of an Investigation into New Mexico Gas Company's Curtailments of Gas Deliveries to New Mexico Consumers, Order Initiating Investigation and Setting Hearing, New Mexico Public Regulation Commission, Case No. 11-00039-UT (Feb. 15, 2011), *available at* http://164.64.85.108/infodocs/ 2011/2/PRS20156381DOC.PDF (last visited Aug. 5, 2011).

[14] The utilities are Public Service Company of New Mexico, Southwestern Public Service Company, El Paso Electric Company, NMGC, Zia Natural Gas Company, and Raton Natural Gas Company.

[15] February 2011 Severe Cold Weather Investigations & Status, Presentation before the Natural Gas Emergency Investigation Legislative Task Force (July 25, 2011) at pp. 1-2.

representatives of the affected municipalities. Since then, the parties have submitted additional written testimony and briefs to the PRC. As of the date of this report, the PRC's investigation is still pending.

Texas

With several million consumers affected by electrical blackouts, the State of Texas was severely impacted by the extreme weather events of early February. Two regulatory agencies in Texas have jurisdiction over the industries in question – the Public Utilities Commission of Texas (PUCT) (which has primary jurisdiction over the electrical power industry) and the Texas Railroad Commission (TRC), whose jurisdiction includes the natural gas industry.

The PUCT reacted at once to the electric outages, asking the state's independent energy market monitor on February 4, 2011 to investigate whether power generators, pipeline companies or others broke market rules.[16]

The PUCT also directed the Texas Reliability Entity, Inc. (TRE) to investigate the Electric Reliability Council of Texas (ERCOT) Energy Emergency Alert Level 3 that occurred on February 2, 2011. At the same time, the PUCT asked El Paso Electric Company to investigate and report back on the weather-related issues surrounding this event.

On February 8, 2011, the TRC held the first state hearing on the outages. One of the witnesses, the TRE, addressed the impact of the rolling blackouts on natural gas service.[17]

On February 15, 2011, the Texas Senate's Committee on Natural Resources and Committee on Business and Commerce jointly convened a hearing to discuss the causes of the rolling blackouts.[18] The hearing included testimony from the PUCT, the TRC, the Texas Commission on Environmental Quality, ERCOT, and the Office of Public Utility Counsel. The House Committee on State Affairs also held a hearing on the causes of the rolling blackouts on February 17, 2011.

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[16] *See* Rebecca Smith, *Texas to Probe Rolling Blackouts, Wall Street Journal* (Feb. 7, 2011).

[17] *See* Press Release: Railroad Commission Emergency posted item to be discussed at 1:30 P.M today, Texas Railroad Commission (Feb. 8, 2011), *available at* http://www.rrc.state.tx.us/pressreleases/2011/020811.php (last visited Aug. 5, 2011).

[18] *See* Chris Tomlinson, *Texas Senate Investigates Power Outages, The Associated Press* (Feb. 16, 2011).

Prompted by the hearings, the legislature enacted a bill to address the perceived causes of the rolling blackout.[19] On June 17, 2011, that bill was signed into law.[20]

The law directs the PUCT to prepare a "weather emergency preparedness report on power generation weatherization preparedness." [21] Under the law, the PUCT must review the emergency operations plans it currently has on file,[22] determine the Texas electricity grid's ability to operate continuously during extreme weather events in the upcoming year, consider the upcoming year's forecasted weather patterns, and recommend improvements to emergency operations plans to ensure electric service reliability.[23] In addition, the law permits the PUCT to require entities to update their emergency operations plan when it does not contain information sufficient to determine whether that entity can perform during adverse weather. The law also permits the PUCT to adopt rules implementing the legislation.[24]

On April 21, 2011, the Independent Market Monitor reported that "there was no evidence of market manipulation or market power abuse" within the ERCOT region.[25] The Independent Market Monitor similarly determined "that the ERCOT real-time and day-ahead wholesale markets operated efficiently and the outcomes are consistent with the ERCOT energy-only wholesale market design."[26]

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[19] SB 1133, 82 Leg., Reg. Sess. (TX, 2011), *available at* http://www.capitol.state.tx.us/tlodocs/82R/billtext/pdf/SB01133I.pdf#navpanes=0 (last visited Aug. 5, 2011).

[20] Another bill was introduced which would have required the PUCT to develop a process for obtaining emergency reserve power generation capacity, but it was not considered during the legislative session. HB 1986, 82 Leg., Reg. Sess. (TX, 2011), *available at* http://www.capitol.state.tx.us/tlodocs/82R/billtext/pdf/ HB01986I.pdf#navpanes=0 (last visited Aug. 5, 2011).

[21] SB 1133, 82 Leg., Reg. Sess. (TX, 2011), *available at* http://www.capitol.state.tx.us/tlodocs/82R/billtext/pdf/SB01133I.pdf#navpanes=0 (last visited Aug. 5, 2011).

[22] P.U.C. Subst. R. 25.53(c)(2) (TX, 2011).

[23] S.B. 1133, 82 Leg., Reg. Sess. (TX, 2011), *available at* http://www.capitol.state.tx.us/tlodocs/82R/billtext/pdf/SB01133I.pdf#navpanes=0 (last visited Aug. 5, 2011).

[24] *Id.*

[25] Investigation of the ERCOT Energy Emergency Alert Level 3 on February 2, 2011, Potomac Economics LTD. (April 21, 2011), *available at* http://www.puc.state.tx.us/files/IMM_Report_Events_020211.pdf at 2 (last visited Aug. 5, 2011).

[26] *Id.*

Appendix: Legislative and Regulatory Responses by the States

On May 13, 2011, the TRE issued a report on whether ERCOT Protocols and Operating Guides were followed during the period leading up to the Energy Emergency Alert event.[27] The TRE concluded that event "was caused by either insufficient or ineffective preparation of generating facilities for prolonged freezing weather."[28] The report went on to find that "ERCOT Market Participants committed potential violations of the ERCOT Protocols and Operating Guides in connection with the event."[29] The TRE will conduct additional investigations as necessary and forward information to the PUCT for further action, as appropriate.[30]

Also, on May 13, 2011, PUCT staff issued a report on El Paso Electric Company's activities during the weather event.[31] PUCT staff did not identify any violations of the Public Utility Regulatory Act or the PUCT's Substantive Rules.[32] The report, however, did conclude that "designed cold weather tolerances of El Paso Electric Company's current generation equipment and/or weatherization preparation were inadequate to prevent failures in the conditions during the event timeframe."[33]

[27] Protocol and Operating Guide Compliance Report of the ERCOT Emergency Alert (EEA) Level 3 on February 2, 2011, Texas Reliability Entity, Inc. (May 13, 2011), *available at* http://www.puc.state.tx.us/files/TX_RE_EEA_Protocol_Comp_Report.pdf (last visited Aug. 5, 2011).

[28] *Id.* at 1.

[29] *Id*.

[30] *Id.*

[31] Report on El Paso Electric Company Weather-Related Issues in February 2011, Staff of the Public Utilities Commission of Texas (May 2011), *available at* http://www.puc.state.tx.us/files/EPE_Report_05-13-11.pdf (last visited Aug. 5, 2011).

[32] *Id.* at 4.

[33] *Id.* at 1.

Appendix: Categories of NERC Registered Entities

All entities that fall within one or more of the following categories must register with NERC. Many entities carry out multiple roles and therefore have multiple registrations.

Function Type	Acronym	Definition/Discussion
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within BA area, and supports interconnection frequency in real-time.
Distribution Provider	DP	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the DP. Thus, the DP is not defined by a specific voltage, but rather as performing the distribution function at any voltage.
Generator Operator	GOP	The entity that operates generating unit(s) and performs the functions of supplying energy and interconnected operations services.
Generator Owner	GO	Entity that owns and maintains generating units.
Interchange Authority	IA	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Load-Serving Entity	LSE	Secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.
Planning Authority	PA	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.

Appendix: Categories of NERC Registered Entities

Purchasing-Selling Entity	PSE	The entity that purchases or sells and takes title to energy, capacity, and interconnected operations services. PSE may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Reliability Coordinator	RC	The entity that is the highest level of authority who is responsible for the reliable operation of the bulk power system, has the wide area view of the bulk power system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The RC has the purview that is broad enough to enable the calculation of interconnection reliability operating limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reserve Sharing Group	RSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each BA's use in recovering from contingencies within the group. Scheduling energy from an adjacent BA to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become a RSG.
Resource Planner	RP	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a PA area.

Appendix: Categories of NERC Registered Entities

Transmission Owner	TO	The entity that owns and maintains transmission facilities.
Transmission Operator	TOP	The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission facilities.
Transmission Planner	TP	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the PA area.
Transmission Service Provider	TSP	The entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.

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Appendix: Electricity - How It Is Generated and Distributed

Electricity is one of the most widely used forms of energy in the industrialized world. According to the U.S Energy Information Administration, in 2009 the U.S. electric utility net generation was 2,372,776 gigawatt hours. Table 1 shows the share of net electricity generation by energy source in the United States.

Energy Source	Net Generation (%)
Coal	44.5
Nuclear	20.2
Natural Gas	23.3
Hydro	6.8
Oil (Petroleum) and other	1.6
Renewables	3.6

Table 1: Share of net electricity generation in 2009 in the U.S. (Source: U.S. Energy Information Administration)

Electric power is produced at generating stations and transmitted via transformers, transmission lines, switching devices and protection and control equipment for delivery to end users. The electric power system as shown in figure 1 is an integrated system made up of generation, transmission and distribution subsystems.

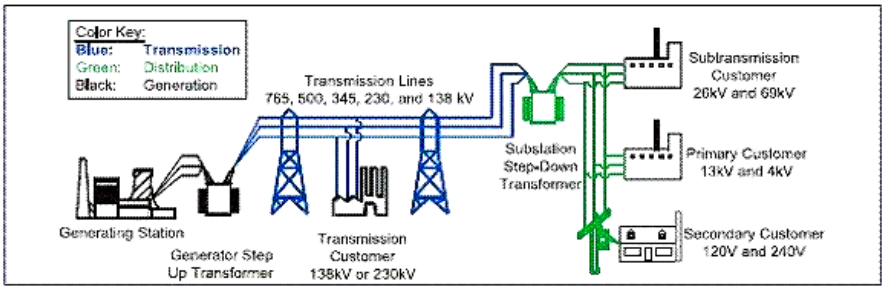

Figure 1 – Basic structure of the electric system (NERC)

Generation

Generating plants produce electricity by burning fuels such as oil, coal, natural gas, or lignite to create steam that drives a turbine, which in turn drives a turbine generator shaft. In a coal-fired plant (figure 2), coal is ground by pulverizers into fine powder, mixed with pre-heated air and injected into a combustor, where it is ignited. The hot combustion gas rises through the boiler and heats water that enters the steam generator. The partially vaporized water enters the steam drum, where steam is separated from the water. The remaining

water cycles through the boiler again, and through tubes lining the furnace walls. The steam is passed through another section of the boiler known as the superheater, where the temperatures are increased to well above boiling.

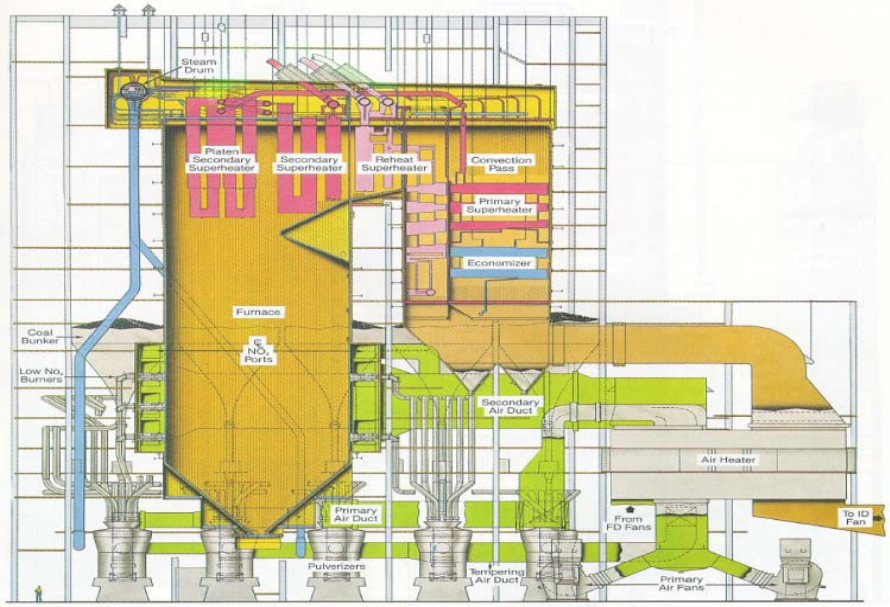

Figure 2 – Typical drum-type coal/lignite boiler plant
(PJM Generation Basics)

The superheated steam, now at very high pressure, passes through a high pressure turbine (shown in figure 3), causing the turbine to spin and turning the shaft of an electrical generator. After passing through the high pressure turbine, the steam is piped back to the boiler to be reheated, then enters an intermediate pressure turbine and low pressure turbine before it passes through a condenser, where the steam is converted back to water, which is usually cycled back to the steam generator for reuse. The mechanical energy generated by the spinning generator shaft is converted to electrical energy for delivery to the electric power system.

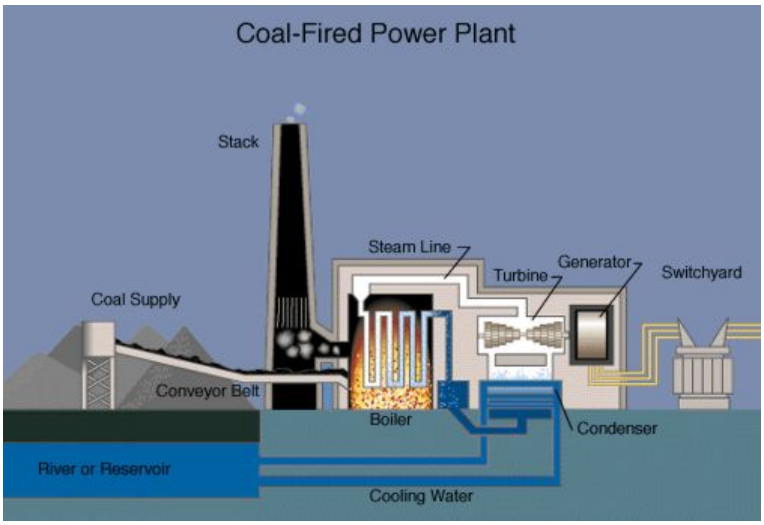

Figure 3: Typical coal burning generating plant with cooling tower (Department of Energy)

In nuclear generating stations, steam is also used to drive a turbine. However, the energy required to produce the steam is derived from nuclear fission, typically fueled by uranium.

Wind turbines use blades to collect the energy of the wind. As wind blows, it flows over the blades, causing them to turn. The blades are connected to a gear box with a drive shaft that turns an electric generator to produce electricity.

In hydroelectric plants, the gravitational force of water flowing downhill drives the turbine generator shaft (as shown in figure 4). The mechanical energy of the spinning shaft is then converted to electrical energy.

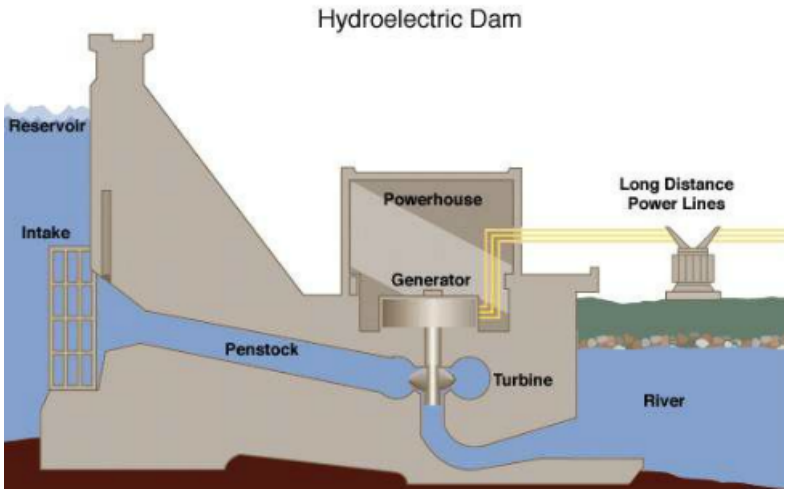

Figure 4: Typical hydroelectric generator
(Energy Information Administration)

Electric energy can also be produced by simple cycle or combined cycle combustion turbines or internal combustion engines, which usually burn natural gas or fuel oil. The combustion turbine drives an electric generator to produce electricity. One advantage of combustion turbines is that they can be started quickly, making them suitable for emergencies and during peak periods, when demand for electricity is at its highest.

A combined cycle combustion turbine is shown in figure 5. Note: a simple cycle combustion turbine plant does not include a heat recovery steam generator (HRSG), steam turbine, and a second generator as depicted in figure 5.

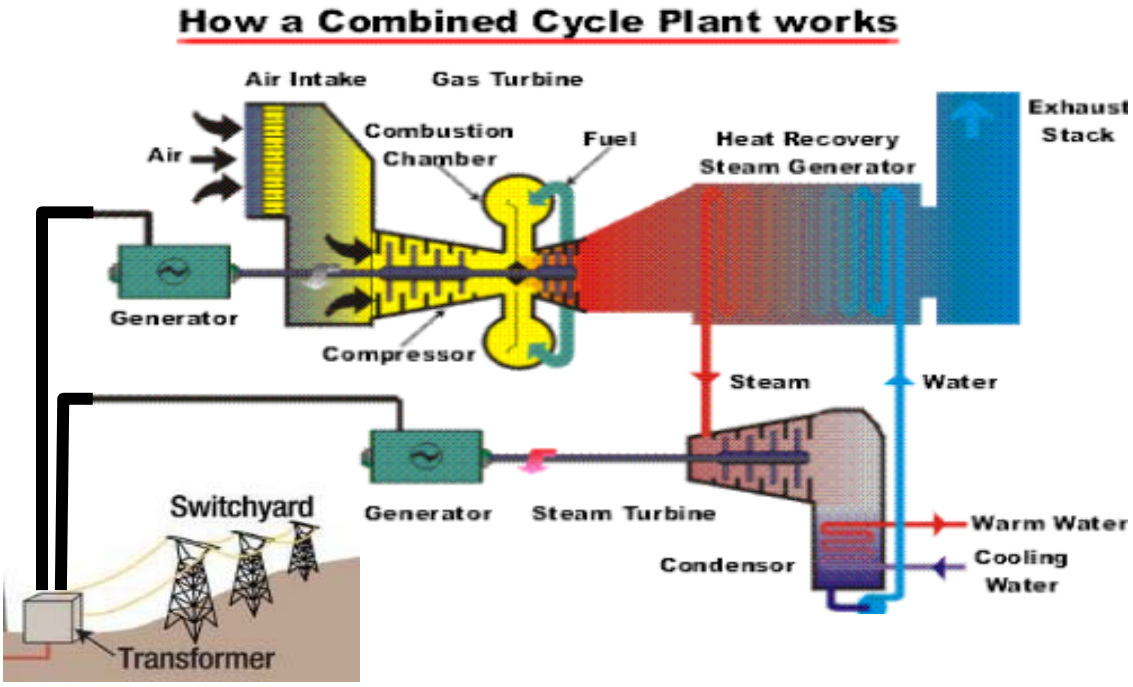

Figure 5: Combined cycle turbine generator with steam generator and HRSG (Washington State University)

Conversion of Mechanical Energy to Electrical Energy

A generator works on the principle of electromagnetic induction, discovered by scientist Michael Faraday between 1831 and 1832. Faraday discovered that the flow of electric charges could be induced in a coil of wire by passing a magnet through the coil. This movement creates a voltage difference between the two ends of the wire or electrical conductor, which in turn causes the electric charges to flow, thus generating electric current.

Every modern generator consists of two main components: the rotor (the moving part) and the stator (the stationary part). In an AC generator, the rotor spins inside the stator. A mechanical device is used to spin or turn the rotor. With every rotation, the changing magnetic field creates a current in the stator windings. A generator does not actually make electrical energy. Instead, it uses mechanical energy supplied to it to cause the movement of electric charges present in the wire of the stator windings, thereby generating an electric current that is supplied to the grid. A generator is akin to a water pump, which causes the flow of water but does not actually create the water flowing through it.

Most large power generators are three-phase generators and have three windings (A, B and C phases), one winding for each phase. In a three-phase

generator, a rotor rotates at the center of the three windings creating the changing magnetic field. Each one of the winding sets produces a voltage. Each phase voltage has a 120º phase angle separation from the other two phase voltages as shown in figure 6. The waveform of the induced voltages is a sine wave (also shown in figure 6) in which each phase voltage periodically reverses direction. The current produced from this generator is known as alternating current (AC).

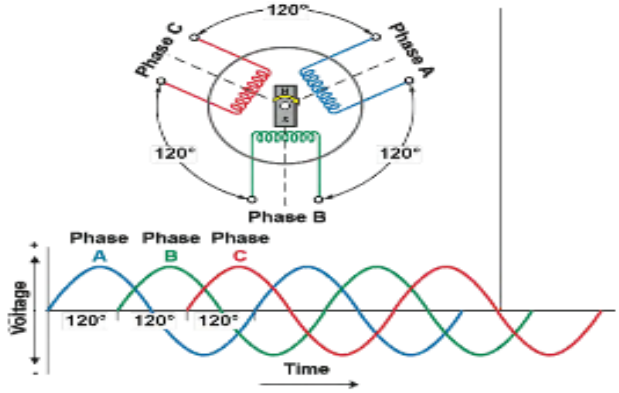

Figure 6: Three-phase generator diagram & waveform
(Electric Power Research Institute)

Figure 7: Three-phase power generator
(Electric Power Research Institute)

There are two general types of AC generator: synchronous and asynchronous. The terms synchronous and asynchronous refer to the relationship between the generator rotor's speed of rotation and the power system speed. Power system speed (or synchronous speed) is the speed of rotation of the AC electrical system to which the generator is connected. When a generator is connected to the power system, the rotating magnetic field of the generator is synchronized with the rotating magnetic field that already exists in the three-phase system. An AC generator can be designed to rotate in-step, or in synchronism,

with the power system's rotating field. This type of AC generator is called a synchronous machine. Most utility power generators and most large motors are synchronous machines.

An AC generator's rotor can also be designed to rotate slower or faster than synchronous speed. This type of machine is called an asynchronous machine. Most small AC motors are asynchronous machines. Induction machines – alternating current machines in which power is supplied to the rotor by means of electromagnetic induction – are the most common type of asynchronous machines. Most wind turbines use induction generators.

Synchronous machines are the most common type of generator used for large-scale power production, and can be used to produce both active[1] and reactive power[2]. This is in contrast to conventional induction machines, which cannot produce reactive power, only active power. The latest design for wind turbine generators, however, includes sophisticated power electronic interfaces and controls that allow these units to inject or absorb reactive power from the grid, as well as providing frequency response, inertial response, etc.

Transmission

Electricity from generators is stepped up to higher voltages by means of a generator step-up transformer for transportation in bulk over transmission lines. Operating the transmission lines at high voltage (100,000 to 765,000 volts) reduces electricity losses from conductor heating and allows power to be transported economically over long distances. The higher the voltage, the lower the current flow needed to transmit the same amount of power. Since losses are related to high current flow, lowering the current lowers the losses. Transmission lines are interconnected at switching stations and substations to form a network of lines and stations called a power grid. Electricity flows through the interconnected network of transmission lines from the generators to the loads in accordance with the laws of physics, along paths of least resistance. When power arrives near a load center, it is stepped down to lower voltages by means of step-down transformers, usually located at substations throughout the system. These substations contain other equipment such as communication, control, protection

[1] Active Power is the useful or working energy supplied by a power source. It is used to perform work such as lighting a room or heating a building or turning a motor shaft.

[2] Reactive Power is used to support the magnetic and electric fields necessary to operate power system equipment. Reactive power is never consumed by the power system and is stored in the electrical and magnetic fields that exist in the system.

and metering equipment. The Bulk Power System (BPS) is predominantly an AC system, as opposed to a direct current (DC) system, because of the ease and low cost with which voltages in AC systems can be converted from one level to another.

Three-phase AC power is normally transmitted by overhead AC circuits, which consist of aluminum conductors with a reinforcing steel core suspended from metal towers by porcelain insulators, as shown in figure 8. Underground transmission circuits can also be used, but are used less frequently than overhead circuits due to the costs involved, as well as the associated reduction in current carrying capacity. Transmission cables installed underground must be insulated, increasing cost and limiting the current carrying capability of the system.

High Voltage Direct Current (HVDC) systems are usually employed for special purposes, including the transmission of large blocks of power from remote sources to load centers or interconnection to systems that operate at different frequencies. A DC transmission system consists of a two conductor line connecting two AC systems. A rectifier at one end of the line converts the AC voltage to a constant DC value and an inverter at the other end reconverts the DC into AC.

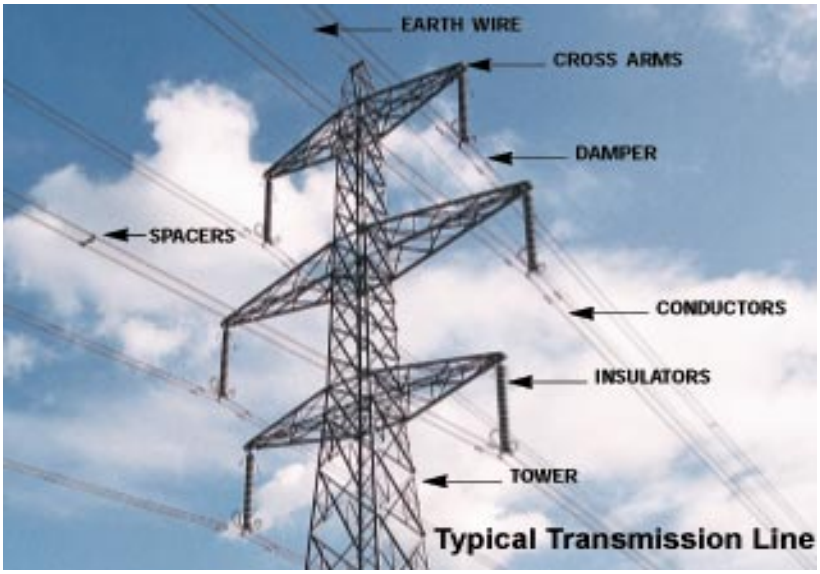

Figure 8: Transmission tower (National Grid)

While the power system is commonly referred to as “the grid,” there are actually three distinct power grids or interconnections in the United States. Figure 9 shows the various interconnections. The Eastern Interconnection includes the eastern two-thirds of the continental United States and Canada from Saskatchewan east to the Maritime Provinces. The Western Interconnection includes the western

third of the continental United States (excluding Alaska), the Canadian provinces of Alberta and British Columbia, and a small part of Mexico near the California border. The third interconnection comprises most of the state of Texas. The three interconnections are electrically independent from each other except for a few small DC ties. Within each interconnection, electricity is produced the instant it is used, and flows over virtually all transmission lines from generators to loads. The frequency at which the various interconnects were designed to operate is 60 Hz.

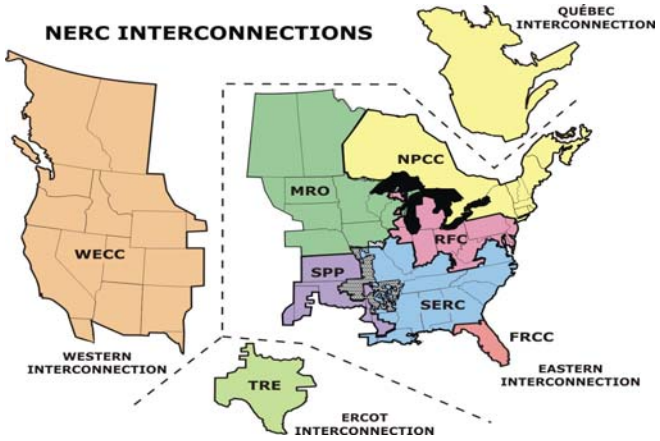

Figure 9: North American interconnections (NERC)

System Frequency

If the total demand from customers is not in balance with the available generation, the electrical frequency of an entire interconnection will deviate from 60 Hz. The target frequency is referred to as the scheduled frequency. When the actual frequency deviates from the scheduled frequency, a frequency deviation has occurred. For example, if the scheduled frequency is 60 Hz but the actual frequency is 59.95 Hz then a -0.05 Hz frequency deviation has occurred. When the supply of generation to the transmission system is inadequate, the frequency falls below 60 Hz. When too much generation is supplied to the transmission system, the frequency rises above 60 Hz. Individual power systems within an interconnection work together to maintain the frequency within a narrow band around the 60 Hz nominal frequency.

Under normal conditions, the power system frequency in a large interconnection (such as the Eastern Interconnection) varies approximately ±0.03 Hz from the scheduled value. If the scheduled frequency is 60 Hz, the normal range is 59.97 to 60.03. These variations are normal and constantly occur due to the varying nature of the interconnection's load. However, large downward, or negative, frequency deviations can trigger automatic load shedding schemes in most areas, designed to reestablish the necessary balance between generation and

load. Depending on the region, automatic under-frequency load shedding usually begins when the frequency declines to levels of 59.3 to 59.7 Hz. Distribution loads are typically shed in various size blocks before generating units start to trip.

System Voltage

The maintenance of voltage within a narrow range is critical to utility customers. Transmission voltage fluctuations of more than ten percent can affect the overall stability of the transmission system. Entities that experience sustained voltage fluctuations equal to or greater than ten percent must file a report with NERC.[3] Capacitor banks, Static VAR Compensators, load tap changing transformers, phase shifters, and voltage regulators are used to control system voltage. Low voltage conditions are usually caused by the loss of critical transmission or generation facilities and may result in the overload of adjacent circuits, which could require bringing power in over tie lines.

Load Balancing

An electric power system must have enough generating capacity to supply expected peak load demand plus a reserve margin to accommodate forced outages of generating units. Operating reserves also are necessary to regulate and respond to unanticipated events such as load forecast errors.

Large frequency deviations from the scheduled value occur when there is a significant mismatch between total load demand and total generation. The frequency rise or decay will in most cases be halted by the action of the speed governors on generators which respond to frequency changes and automatically adjust generation to meet demand. Governor action is supplemented by the Automatic Generation Control (AGC) system which over a period of several minutes brings the frequency and interchange (energy transfers that cross Balancing Authority boundaries) back to schedule.

AGC can be a very effective tool during system restoration. The primary function of AGC is to make continuous and automatic adjustments to the output of selected generators in a way that meets load demand and the established interchange schedule at the desired operating frequency. AGC software is normally designed to control a defined portion (within the Balancing Authority boundaries) of the interconnected system. To accomplish the AGC control function, control parameters are continuously monitored. The control parameters

[3] Reliability Standard EOP-004-1 (Disturbance Reporting).

consist of an actual frequency reading and all tie-line MW flows to neighboring Balancing Authority areas. These control parameters are selected and normally fixed for the portion of the system being controlled. A key assumption to the typical AGC control strategy is that the power system is operating in an interconnected mode.

Distribution

Some larger industrial and commercial customers take service at intermediate voltage levels (4,000 to 115,000 volts), but most residential customers take their electrical service at 120 and 240 volts. Residential customers receive power via overhead or pad mounted transformers supplied by distribution feeders from substations. The transformers step down the voltage from a typical voltage of 13,000 volts to 120/240 volts. The lines carrying the power to a business or residence usually terminate at an electric meter owned and maintained by the distribution company. The meter records the energy consumed by the end user and is read periodically by the distribution company to monitor energy usage and for billing purposes.

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Appendix: Power Plant Design for Ambient Weather Conditions

Geographic location and the corresponding ambient weather conditions, including expected temperatures and wind speed, have a direct impact on the preferred design for generating facilities. In the northern regions of the United States, most generating plants (especially steam-cycle plants) are designed and constructed with the boilers, turbines/generators, and certain ancillary equipment housed in one or more enclosed buildings. In the colder months, heat radiated from boilers, other generation equipment, and supplemental heaters can generally maintain temperatures at a high enough level to prevent freezing. Enclosed areas are generally designed and constructed with fresh air inlets and roof-mounted exhaust ventilators for cooling purposes during the hot weather months.

Enclosed coal fired power plant in the northeastern United States (Allegheny Energy)[1]

In the southern and other warm weather regions of the U.S., generating plants are designed and constructed without enclosed building structures, with the boilers, turbine/generators, and other ancillary systems exposed to the weather, in order to avoid excessive heat build up. For the colder months, when temperatures may fall below freezing, generation owners and operators undertake specific freeze protection efforts, which typically involve a combination of heat tracing, insulation, temporary heating, and temporary wind breaks (to prevent heat loss from normal operations and from supplemental heating sources).

[1] *Available at* http://www.industcards.com/st-coal-usa-wv.htm (last visited Aug. 10, 2011).

Non-enclosed coal fired power plant in the southern United States (Luminant)[2]

Common Freezing Problems

Some power plant components and systems are susceptible to freezing. Any power station system that uses water, air (which can contain moisture), or rotating machinery (which uses lubricating oil) can develop operational problems or trip off-line as a result of sub-freezing temperatures, unless adequate cold weather protection is in place.

- Instrumentation - Instrumentation provides operational data necessary for process monitoring and control systems. Freezing often may occur not in the instrumentation itself, but in the sensing lines that run from piping, pressure vessels, and tanks that contain water or steam. The sensing lines are filled with a static water column that, if frozen, will send incorrect data, possibly resulting in unit trips, load rejection, unit runback schemes, or incorrect operator actions. Critical instrumentation sensing lines that are susceptible to freezing include lines used to monitor boiler steam drum water level, deaerator pressure, feedwater heater water levels, and various critical cooling water flows (generator, turbine oil cooling, etc.).

- Feedwater systems - The condensate and boiler feedwater systems for steam-cycle generation units utilize water from the condenser and add heat (through a series of feedwater heaters) and pressure (through condensate and boiler feedwater pumps) to increase cycle efficiency before the water enters the boilers. Piping, pressure vessels, and valves contained in these systems are all susceptible to freezing. This is especially true of generation units that are not in operation at the onset of freezing temperatures, due to static water in the feedwater systems. In addition, the reverse osmosis

[2] *Available at* http://www.powermag.com/environmental/Luminants-Oak-Grove-Power-Plant-Earns-POWER-s-Highest-Honor_2877_p2.html (last visited Aug. 10, 2011).

equipment, demineralizers, filters, and storage tanks often found in condensate make-up water systems are susceptible to freezing.

Cooling Water Systems

- Cooling Water Intakes - Steam cycle power plants require large quantities of cooling water, often supplied by rivers or lakes. Water drawn from a river or lake is filtered through trash racks and circulating water screens to remove tree branches, debris, and fish. When temperatures drop below freezing, ice can clog racks and screens, limiting the flow of cooling water. Water intakes can also become clogged by fish kills during extreme cold weather, as happened in Texas in 1989.

- Cooling Towers - Cooling towers lower the temperature of water used in the cooling process so that it can be reused (reducing the amount of water taken from lakes and rivers) or discharged at lower temperatures. Cooling towers use mechanically induced draft or natural draft designs. Mechanical cooling towers (box) have fans mounted on the top to draw air through the water as it falls over trays to remove the heat gained in the steam condenser. Natural draft cooling towers are of the familiar, hyperbolic design that can be seen at many large coal and nuclear power plants. During extended periods of freezing temperatures, ice can accumulate on the trays in the towers and affect operations or damage the unit.

- Equipment Cooling Water - Various equipment and systems in power plants require cooling water to stay operational. These include turbine lubricating oil coolers, generator/hydrogen coolers, pump and fan bearings, and air compressors. Freezing of the piping, valves, and instrumentation sensing lines in these systems can cause derates or outages.

- Sluicing/Service Water Systems - Sluicing water is used to remove bottom ash from coal-fired boilers. Icing problems in the bottom ash removal system can interfere with ash removal and may lead to derates or outages. Service water is used for various wash down systems and fire protection systems. Loss of service water due to freezing should not affect unit capacity, but could affect equipment protection systems.

- Wastewater Systems - Various power plant systems that use water can create waste streams that must be treated for contaminants before re-use or discharge. Those systems include boiler blowdown, cooling tower blowdown, various cooling systems, bottom ash sluicing water, and service water systems.

Freezing of valves and piping on these systems can result in the accumulation of wastewater, which could affect other systems.

Emission Reduction Systems

- Sulfur Dioxide Removal Systems - Among the methods available to reduce and remove sulfur dioxide from emission flue gas on coal plants, the predominant technology has been use of wet lime or limestone scrubbers. Lime or limestone contains calcium oxide, which when mixed (slaked) with water forms calcium hydroxide. Calcium hydroxide is sprayed through the flue gas to produce a chemical reaction to form calcium sulfite or sulfate (gypsum). As the waste product is processed, it contains less and less water, which is then reused in the scrubber. The scrubbing and waste processes require many runs of piping and instrument/control locations, many of which are susceptible to freezing. Freezing problems on piping runs or sensing lines could cause scrubber chemistry problems, tank overflows, etc., which could lead to derates or unit shutdowns if the plant is unable to stay within permitted emission limits.

- Nitrogen Oxides Reduction Systems - As with sulfur dioxide systems, numerous technologies are available to reduce nitrogen oxides in fossil fuel plants. Many of these technologies use water in the emissions reduction process. These systems are susceptible to freezing that can lead to failure in the emissions reduction process, resulting in derates or unit shutdowns.

Control Air Systems, Control Drives, Valve Actuators, Valves

- Freezing in Control Air Systems - Air is compressed and used to operate pneumatic control valves, boiler damper control drives, and various other pneumatic controls in the plant. Moisture in the air can condense and accumulate in lines, air receivers, and component control mechanisms. If moisture is not removed (through use of air dryers and air receiver blow-downs), these pneumatic controls can freeze and cause equipment controls to malfunction or fail, which can in turn cause a unit shutdown or limit the unit's output.

- Sluggish Valve Operation - When exposed to severe cold weather, the operation of valves and control valves can become sluggish. This can lead to instability in boiler or turbine controls and ultimately lead to a unit trip.

- Lubricating Oil - Various types and grades of lubricating oil and grease are used in power plants on rotating machinery and other moving parts. As the temperature decreases, the lubricating properties and viscosity of these oils change, possibly affecting operation of the equipment.

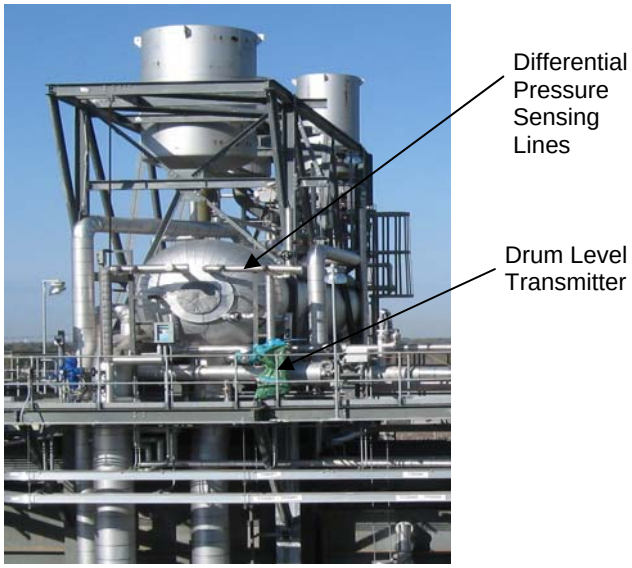
Fuel

- Coal - Severe cold weather can limit or prevent the transfer of coal into a plant. Coal in Texas (lignite) typically contains between 30 and 40% moisture. When temperatures are low enough to freeze moisture in the coal, the coal may slide on conveyor belts or block belt transfer points, chutes, and crushers, limiting supply.

- Natural Gas Supply - Freezing weather can cause gas valves to malfunction, adversely affecting gas supply to the units.

- Fuel Oil - During cold and freezing weather, fuel oil supplies in storage can gel without the appropriate additives. Gelled fuel oil can affect pump and burner performance, which in turn affects the unit's output. Some types of fuel oil must be heated before they can be used in cold weather.

Steam Drum Level Measurements



One of the most critical measurements made on a drum type steam boiler is the water level in the main drum. Too high a water level can result in water being

injected into the boiler tubes or steam turbine, damaging the boiler tube or turbine blade. Too low a water level or no water can result in overheating the drum or boiler tubes, leading to drum or boiler tube damage.

The steam drum in a southern plant can be located outside, near or at the top of the boiler. During the February 2011 cold weather event many of the plants had problems with freezing in the drum level water level regulating system.

A typical drum level measurement system works by maintaining the differential pressure between the steam side and water side of the drum to a constant value. The drum level transmitter monitors and regulates this differential pressure by controlling the amount of water being added or removed from the drum. On a normal drum, the water level is controlled to approximately plus or minus 2 inches of the desired level.

Appendix: Impact of Wind Chill

Wind Chill Factor

The term "Wind Chill Factor," is often used to explain the additional heat loss people experience through convection cooling when exposed to the wind. Whenever there is a temperature difference at a surface, *e.g.*, the difference between normal body temperature and ambient air at a lower temperature on the surface of human skin, heat is conducted across the surface from the warmer body to the cooler air. In the process, the layer of air on the surface is warmed and forms a thermal boundary which tends to slow the rate of heat loss. Wind accelerates the heat loss by literally sweeping away that boundary layer and replacing it, continuously, with air at the ambient temperature. This acceleration of heat loss caused by the wind makes people feel that the air temperature is colder than it actually is. This feeling is quantified by assigning a stationary air temperature, known as the Wind Chill Temperature, which yields an equivalent perception of cold.

The polar explorer and geographer Paul Siple first used the term "wind chill" in 1939. During the second expedition of Admiral Richard Byrd, Siple and his partner Charles Passel conducted experiments at Little America, Antarctica, to determine the time required to freeze water in plastic vials exposed outside in the wind. They developed a formula for relating heat loss to wind speed and air temperature, expressed in units of atmospheric cooling-watts per square meter. Later, the formula was modified to allow computation of a wind chill equivalent temperature.

Wind Chill Temperature is only defined for ambient temperatures at or below 50 degrees Fahrenheit and wind speeds above 3 mph. Bright sunshine may increase the wind chill temperature by 10 to 18 degrees.

Wind Chill Effect on Inanimate Objects

The Wind Chill Factor, per se, applies only to human beings and animals. The only effect wind chill has on inanimate objects, such as car radiators and water pipes, is to more quickly cool objects to the current air temperature. Objects will not cool below the actual air temperature. For example, when the temperature outside is -5 degrees and the Wind Chill Temperature is -31 degrees, a car's radiator will not get any colder than -5 degrees. Similarly, if the ambient temperature is above freezing, stationary water in piping exposed to the wind will not freeze, no matter how strongly the wind may blow.

Appendix: Impact of Wind Chill

Wind Chill Effect on Industrial Plants

Industrial plants, including electric generating stations, can nevertheless be affected by the accelerated rate of heat loss, or cooling, caused by air movement. During the hot summer months, this cooling effect can help prevent temperatures from exceeding equipment operating limits. For this reason, many plants in warmer climates are of an open-air design, without walls or enclosures. In the winter, however, the enhanced cooling from the unimpeded flow of air can cause freezing problems.

On cold days when the outside temperature drops below freezing, sustained high winds can quickly and continuously remove the heat radiating from boiler walls, steam drums, steam lines, and other equipment in an electric generating station, causing ambient temperatures to drop below freezing in spite of the heat being produced by the facility. If stationary water lines, such as those used for differential pressure measurement, are exposed to the wind under those conditions, they can freeze if they lack adequate freeze protection such as heat tracing and insulation. Wind screens and enclosures can slow the rate of heat loss caused by high winds, while at the same time acting to contain heat supplied by supplemental space heaters at critical locations.

Wind Chill Effect on Electric Demand or Load

The accelerated cooling effect of the wind affects buildings and homes throughout the community, and can significantly increase demand for electric power. In particular, buildings that are not well insulated, with frequently opened doors or drafty windows, can experience higher rates of heat loss on windy days, increasing the demand for heating energy.

During the February 2011 weather event, ERCOT engineers and operators concluded, based on archived historical data, that the forecasted wind speeds would significantly increase the load on the system. They therefore increased the conventional load forecast by 4000 MW to account for the added load created by high winds combined, with low temperatures.

Appendix: Winterization for Generators

Extreme cold weather can cause generators to fail for many reasons, including the failure or absence of heat tracing on key components, missing or inadequate wind breaks, inadequate insulation, lack of supplemental heating devices, human error, or inadequate training, maintenance, or preparation. As discussed below, effective winterization programs incorporate both physical components and operational processes to protect generating plants from freezing weather.

Physical Components of Winterization

Physical freeze protection is accomplished by three primary components:

- Heat tracing – the application of a heat source to pipes, lines, and other equipment that must be kept above freezing;
- Thermal insulation – the application of insulation material to inhibit the dissipation of heat from a surface; and
- Windbreaks – temporary or permanent structures erected to protect components from wind.

Generators use other temporary measures to prevent freezing in plants, including installing space heaters, draining non-essential water lines, and placing small heat lamps in cabinets.

Heat Tracing

Types of Heat Tracing Cable

Electric heat tracing involves the application of heat to the outside of pipes or other lines to maintain proper operating temperature. A heat tracing system is typically made up of the following: (i) heat tracing cable wound around the pipe; (ii) a thermostat that measures ambient air temperature; (iii) thermal insulation; and (iv) a power source. The failure of any of these components can result in frozen instrumentation.

There are five main types of heat trace cable. "Self-regulating" cable automatically increases power to produce additional heat as the temperature falls. It can be used on metal or plastic components for freeze protection, temperature maintenance, and foundation heating, and is typically found on sensing lines and other ancillary components. However, it cannot be used on surfaces that have high surface temperatures.

"Power-limiting" heat tracing is similar to self-regulating heat tracing in that it increases power and heat as temperatures drop, and decreases power as temperatures rise. It is specifically designed to produce high temperatures and to be used on high surface temperature fixtures.

"Parallel constant watt" heat tracing cable consists of a continuous series of short, independent heating circuits that maintain a consistent output of heat for up to several hundred feet. One benefit of this type of cable is that if one of the independent circuits fails, the rest of the cable will continue to operate. However, the length of the cable is limited, based upon the distance between the circuits, making it impractical for certain situations.

A "series constant watt" heat tracing cable is designed specifically for components that need longer circuit length. These cables are made of high-resistance wire that is powered at a particular voltage to generate heat. However, a break anywhere along the cable will result in failure of the entire heat tracing installation.

Another common type is "mineral insulated" heat tracing cable, which is typically used to maintain high temperatures, or in locations where it will be exposed to high temperatures. Mineral insulated cable is also used to provide heat over long distances, and is often used to protect high temperature steam lines.

Power Supply

Each heat tracing cable must be connected to a power source. In a typical installation, several cables covering one component of a generating unit will be connected to a freeze protection electric panel that contains circuit breakers or fuses for the various circuits. Depending on the size and layout of the generating unit, it may have dozens of freeze protection panels. These panels are often equipped with visual displays that indicate when the system is energized and when the heat tracing is activated. Images 1 and 2 are examples of the inside and outside of a new freeze protection panel.

Figure 1: Freeze Protection Panel Interior

Figure 2: Freeze Protection Panel Exterior

As can be seen in the example above, lights on the front of the panel indicate the status of the freeze protection system. Such indicator lights must be regularly monitored and tested by plant employees, since control room personnel are not always able to monitor panels remotely.

The failure of a freeze protection panel during cold weather can cause heat trace cables connected to that panel to fail. Failure to properly maintain or inspect the panel can cause corroded connections to go unnoticed and go unrepaired, possibly resulting in a short circuit that shuts off power to other panels.

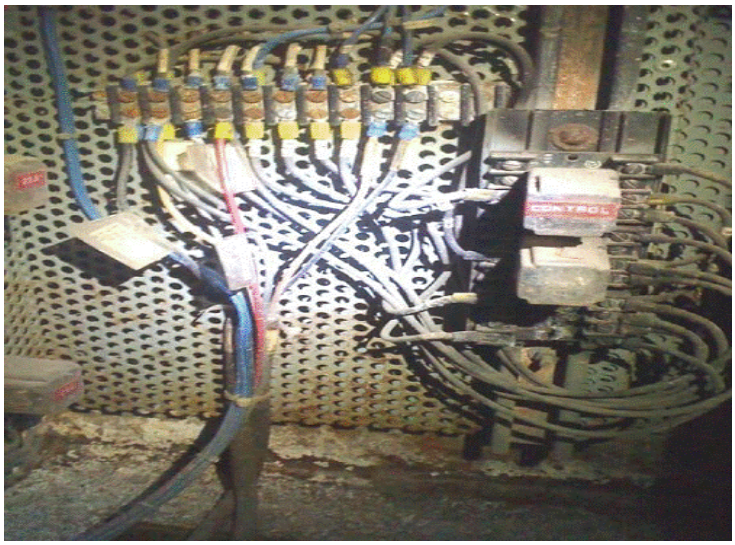


Figure 3: Corroded Freeze Protection Panel

Thermostats

Although the panel is always energized, heat tracing cables are turned on only when low temperatures call for freeze protection. Power to the cable is supplied either by a contactor (wherein two metal plates, usually separated, are pressed together to power the cables), or by a solid state controller. In most cases the system is turned on by a thermostat located at the panel. In some cases plants initiate freeze protection procedures at certain specific temperatures, and in some instances, the heat tracing must be turned on manually by plant personnel.

Thermal Insulation

A layer of thermal insulation is placed on top of the heat tracing that is installed on a pipe. This insulation is similar to home insulation, but is composed of different materials. A weatherproof skin is typically applied as an external layer to protect the insulation and heat trace from damage.

Figure 4: Insulated Piping with Heat Tracing

Thermal insulation plays a significant role in freeze protection, particularly in windy conditions, by preventing rapid heat loss. However, even small gaps in insulation have been known to result in frozen lines.

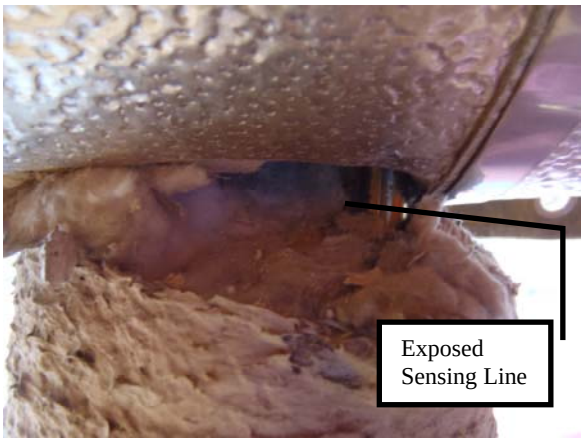


Figure 5: Gap in Insulation

In addition to the pipe itself, valves, flanges, traps and fittings should be insulated to the extent possible. Non-insulated valves, like those pictured below, can cause pipe to freeze if enough surface area is exposed to freezing wind conditions.

Figure 6: Exposed valves emerge from thermal insulation and are not heat traced

Windbreaks

The third major component to winterization is windbreaks. Windbreaks are temporary or permanent structures used to prevent wind from blowing directly over exposed components and dissipating heat at an increased rate.

Figure 7: Temporary windbreak created with scaffolding and tarpaulin

Other Winterization Efforts

In addition to the three major winterization techniques, generating stations sometimes use other freeze protection measures. These include keeping water flowing to reduce freezing, draining liquids from valves, purging drained lines of water with compressed air, and installing space heaters in enclosed areas to raise ambient air temperatures.

Winterization Processes

Although designing freeze protection systems for exposed areas is critical to cold weather operation, preparation for freezing conditions is equally important. In order to achieve good freeze protection, a generator must know what areas are likely to freeze, and must take steps to ensure that appropriate procedures are put in place. The following paragraphs describe some of the steps that can be taken to prepare for winter, and discuss how the proper use of checklists can help plant managers implement effective winterization measures.

Winter Preparation

Preparation for winter weather should begin well before its arrival, and many generator operators in Texas and the Southwest start their winterization programs in the fall of each year. These procedures include verifying that installed heat tracing is working, components are properly insulated, space heaters are operational, fuel switching can be initiated, and instrument systems are free of moisture. Many generators also verify that their inventory of freeze protection equipment – such as heat lamps, heat guns, propane torches, tarps, de-icing

material, fuel, insulation, sand, and extension cords – is adequate for the upcoming season. Timeliness is an important aspect of pre-winter preparation – it should begin early in the season so that there is time to make necessary repairs before cold weather hits.

In addition to pre-season preparation, generating stations typically have a set of procedures that are initiated whenever a winter storm is expected. Much of the work that is done before a storm arrives is similar to pre-season preparation. However, the pre-storm procedures may include calling in additional operators and maintenance personnel, moving motor vehicles into garages, draining non-essential water lines, and moving portable heaters into position.

As winter weather sets in, generating stations may adjust their operations to protect against freezing conditions. Such changes may include switching instrument air to nitrogen backup, warming up standby boilers every two hours, opening bypass valves on steam traps, and rotating pumps every two hours.

A critical component of winterization plans is the opportunity for post-winter critiques and reports on lessons learned. Applying lessons learned is sometimes done informally but some generators go further, requiring plant managers to conduct post-winter meetings to identify necessary improvements and to file written reports on the plant's performance during the winter season.

Checklists

In order to ensure that all of the plant-specific tasks are properly completed, many generator operators create checklists for plant personnel to follow. Although the form of such checklists may vary depending on the size of the plant and the types and locations of the generating units, effective checklists tend to have certain characteristics.

Good checklists are sufficiently detailed to allow plant operators and maintenance personnel to adequately prepare for and deal with cold weather events. For example, a checklist may specify who is responsible for assigning personnel to freeze protection duty, or may identify specific tasks triggered by different freeze alert levels.

A checklist can be broken down not only by task, but also by area and by individual components or areas to be checked. For example, the checklist can specify which particular lines should be drained and which vents should be closed.

Appendix: Winterization for Generators

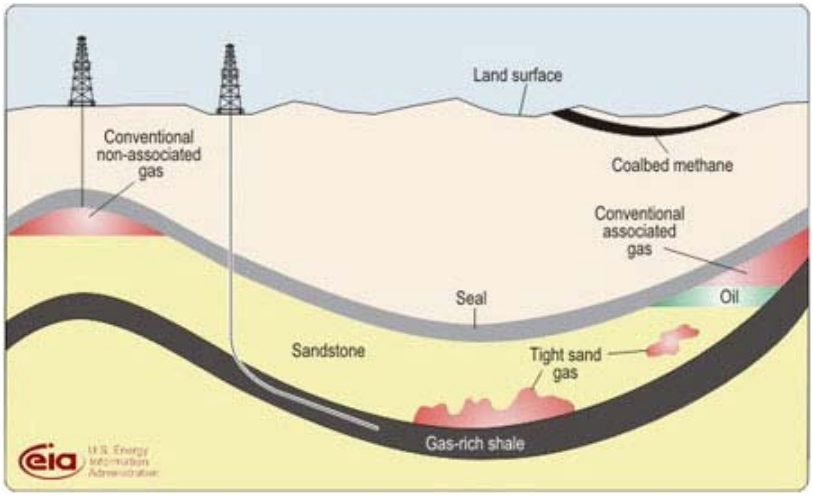
A list that is lacking in detail and that only includes general tasks such as turning off vent fans or checking boiler and duct air heater enclosures will not be effective. Plant employees might understand which components should be included in such general references, but non-specific descriptions are inadequate to ensure that all systems are identified and checked.

Checklists can also offer generating stations the ability to audit their performance in implementing winterization. A common feature of effective checklists is a requirement that employees initial and date the checklist for each task completed. Not only does this provide confirmation that the tasks were completed, but it also holds operators and maintenance staff accountable for their performance.

Appendix: Natural Gas – Production and Distribution

What Is Natural Gas?

Natural gas is a highly compressible, naturally occurring mixture of hydrocarbons, principally containing methane, that migrate upward through geological formations until the migration is halted by a physical barrier that allows the natural gas to accumulate in the small pore spaces within a geological formation, or reservoir. The physical barrier is a non-permeable formation that is known as a reservoir seal or caprock. The type of formation where the natural gas can accumulate, which can include sandstone, coal as well as shale, depends upon the location of deposition of the original organic material and the geologic formations that lie above. To access the natural gas that has accumulated within the reservoir, drilling companies will drill down to the formation using drilling rigs that punch into the formation using drill bits and long string pipes to bring the natural gas to the surface at the well site.



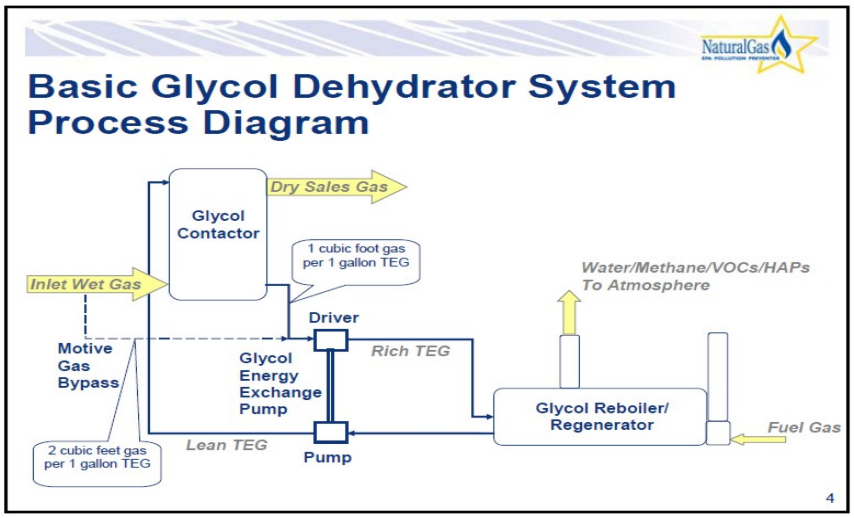
(Energy Information Administration)

While in the ground, the natural gas is under high pressure. When these formations are produced, the natural differential in pressure, between the high pressure in the formation and lower pressure at ground level, can provide the driving force to move the gas to the surface. The company in charge of producing the natural gas, by allowing the natural gas to flow from the subsurface formation up to the surface, will drill several wells to maximize its ability to produce the natural gas while maintaining the integrity of the reservoir within the geological formation to ensure a long and active production life.

As part of the natural gas stream that reaches the surface and is produced from the wellhead, there are many other gas constituents other than methane. Heavier hydrocarbons, such as ethane, propane, butane, and pentane plus, are also produced along with the methane-rich gas stream. After production, these heavy hydrocarbons or natural gas liquids (NGLs) can be removed through processing and sold separately from the natural gas. Other gases, such as hydrogen, carbon dioxide, nitrogen, oxygen, sulfur, and hydrogen sulfide, are also produced, and most of the gases will be removed from the

natural gas stream through the use of treating plants. Unlike NGLs, some of these gases are undesired impurities with little or no commercial value.

Another common byproduct of natural gas production is water. Just as natural gas can migrate through geologic formations and into reservoirs, water and crude oil can follow the same process. Water that accompanies natural gas is removed through the use of dehydration facilities located at or near the wellhead.[1] The water is then commonly injected back into the outer limits of the reservoir's geological formation to help produce additional natural gas from the reservoir by displacing the natural gas from the pore spaces within the geologic formation and push the natural gas toward the producing wells. Unless water is removed from the gas stream, it can freeze in the pipeline and stop the flow of gas from the wellhead.



(Environmental Protection Agency)

Over time, multiple wells are drilled into the formation in order to maximize production of natural gas in the reservoir. After each well is tested and examined by the production company, the wells are connected through a series of pipelines increasing in diameter as more gas is gathered and transported through the gathering pipeline.

[1] The dehydration of natural gas usually involves one of two processes – absorption or adsorption. Absorption occurs when the water vapor is taken out by a dehydrating agent. Adsorption occurs when the water vapor is condensed and collected on the surface. The absorption process requires a chemical with an affinity for water, such as glycol, which is the most commonly used dehydration agent. After absorbing the water, the glycol falls out of solution to the bottom of the tank where the water-rich glycol is removed. The adsorption process is a physical-chemical process in which the gas is concentrated on a surface of a solid or liquid to remove the impurities. Natural Gas Supply Association, Processing Natural Gas, *available at* http://www.naturalgas.org/ naturalgas/processing_ng.asp (last visited Aug. 5, 2011); Saeid Mokhatab, William A. Poe & James G. Speight, Handbook of Natural Gas Transmission and Processing 262 (Elsevier 2006).

Depending upon the impurities in the natural gas stream, the pipeline will funnel the natural gas stream to processing and treatment plants. The treatment plants are used to remove impurities and other objectionable material usually before the natural gas stream is transported to the processing facilities.

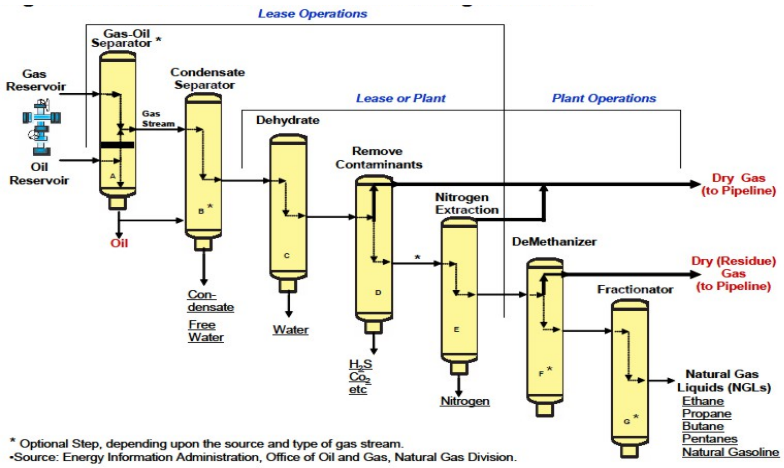
The natural gas stream often contains other contaminants that must be removed before the natural gas stream is delivered to downstream pipelines. Some of these contaminants are hydrogen sulfide, carbon dioxide and other sulfur-based impurities, which are sometime referred to as "acid gas."[2] When hydrogen sulfide combines with water in the natural gas stream, sulfuric acid forms. Similarly, carbon dioxide that combines with oxygen forms carbonic acid. These acid gases can cause damage which, if left unchecked, could lead to pipeline failure.[3]

The processing plants typically remove NGLs through a refrigeration process that involves a form of rapid cooling of the natural gas stream. Two types of this cooling process are mechanical refrigeration, as used in lean oil absorption, and turbo-expander or cryogenic process. The technology used will depend upon the age of the processing facilities as well as the desired result. Mechanical refrigeration is a process whereby the natural gas stream is chilled by a vapor compression refrigeration process, similar to the process used by a refrigerator or an air conditioner, but producing much colder temperatures. This is coupled with the use of glycol as an absorption fluid that combines with the NGLs and falls out of the gas stream. In the cryogenic process, the high pressure natural gas stream is rapidly expanded by decreasing the pressure. This process causes the gas stream to cool rapidly (Joule-Thomson Effect)[4] to temperatures that will cause the NGLs to move from a gaseous phase to a liquid phase. The NGLs fall out of the gas stream and are collected for sale and additional processing. The residual gas, from which the NGLs have been removed, is transferred to a downstream pipeline for transmission to end users. Both of the above processes are effective means for recovering NGLs and for reducing the possibility that NGLs will condense and fall out of the gas stream as liquids that could cause damage to downstream equipment.

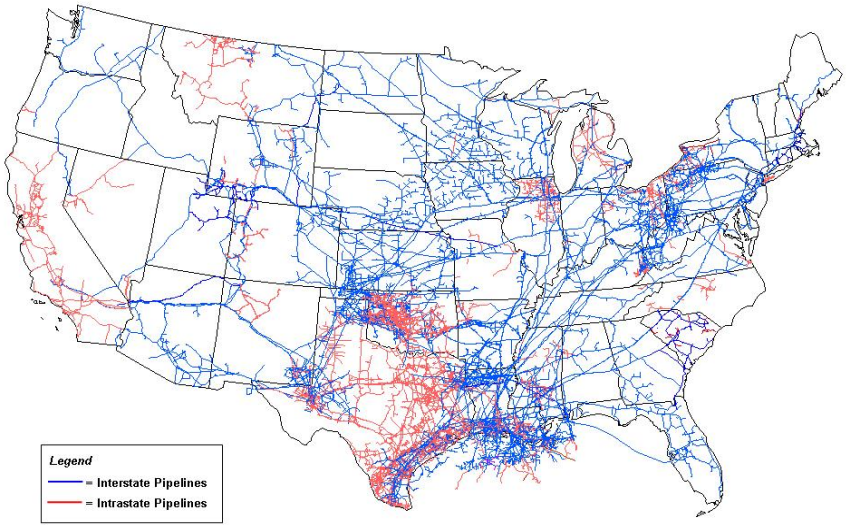
[2] Natural gas containing hydrogen sulfide is considered "sour" gas while natural gas without hydrogen sulfide is considered "sweet" gas. *Id*. at 261.

[3] Frøydis Eldevik, *Safe Pipeline Trasmission of CO2,* Pipeline & Gas J., April 2011, Vol. 238 No.4, p. 3, *available at* http://www.pipelineandgasjournal.com/safe-pipeline-transmission-co2?page=3 (last visited Aug. 5, 2011).

[4] Joule-Thomson Effect is the change in temperature or cooling effect resulting from the rapid expansion of pressurized natural gas through a valve.



After treating and processing, the natural gas can be transported to market centers by the intrastate and interstate pipeline system. This network is made up of more than 210 pipeline systems with over 305,000 miles of varying diameter pipeline, 1,400 compressor stations, and 400 underground storage facilities, all connecting the various natural gas production areas, both onshore and offshore, to multiple markets throughout the United States.[5]



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

Types of pipeline systems

The interstate pipelines can divided into two types of systems – long-haul and reticulated. Long-haul pipelines receive natural gas supplies from producers and

[5] U.S. Energy Information Administration, *About U.S. Natural Gas Pipelines – Transporting Natural Gas, available at* http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html (last visited July 20, 2011).

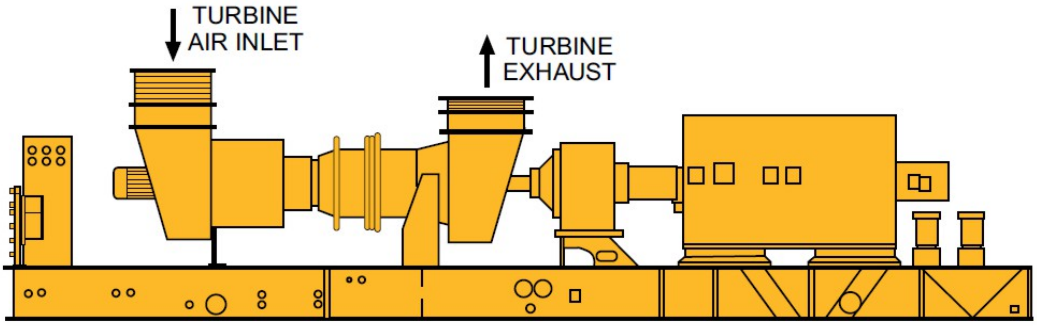
processors and transport it across hundreds of miles to market areas outside the production areas. Reticulated pipelines resemble a spider web that overlays both the supply areas and the market areas, and typically have multiple lines that can change direction of gas flow through the system, depending upon market needs.

Pipeline Design

A natural gas pipeline system can be as simple as a single diameter pipe receiving gas from one source and transporting it to a single delivery point, or as complex as a network of multiple diameter pipes covering hundreds of miles with compressor stations, storage facilities, and numerous receipt and delivery points. In order to move natural gas supplies from the supply areas to the market areas, a pipeline must be designed to transport the required volume of gas supplies, while maintaining system pressures along the length of the pipeline necessary to serve its shippers.

The design of all pipeline systems starts with the same basic idea, the need to transport a specific volume of natural gas from at least one supply source to a specific destination while maintaining contractual delivery pressure obligations. Due to frictional loss resulting from the gas flow, the pressure of the gas stream will decrease. Compressor stations are designed to re-pressurize the gas stream in order to overcome the pressure losses associated with movement of gas in a pipeline. Compressor stations are above-ground facilities where the pipeline connects with large individual compressor units through various smaller pipelines or “yard piping” as well as meter and regulation equipment. Compressors are mechanical devices that increase the pressure of the gas stream. After the gas stream has been re-pressurized, the gas re-enters the pipeline for further transmission to downstream markets. Compression facilities are needed along the length of the pipeline, and are typically placed at 40 to 60 mile intervals.

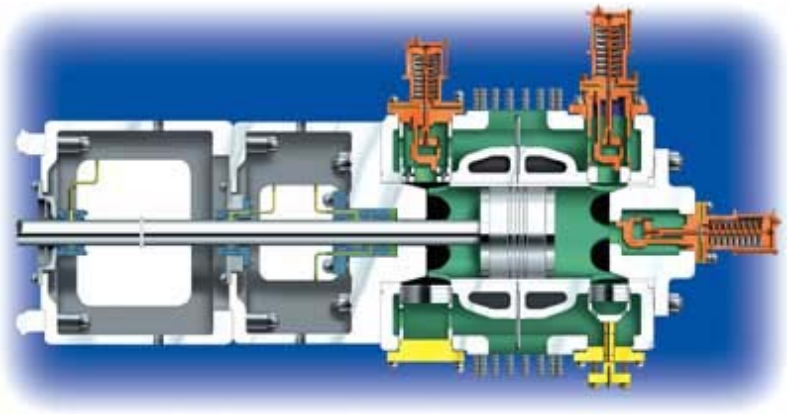
Compressors are split into two basic parts, the compressor and the driver, or motor. The motor, which can be fueled by electricity or gas-fired, powers the compressor unit that compresses the gas. The two types of compressors that are most commonly used by the interstate natural gas companies are centrifugal and physical displacement or reciprocating compressors. Centrifugal units are turbines that spin at high rates of speed to compress and accelerate the gas stream. These compressors are used to accommodate high flow rates at high pressures. Most interstate pipeline systems use centrifugal compressor units on their mainlines. The following is an illustration of a centrifugal compressor and gas-fired motor.



(Solar Turbines Incorporated (a Caterpillar Company))

The gas stream enters the inlet or suction side of the compressor unit, where it is forced through the rotating turbines at high speed and exits the compressor at the discharge side, moving back into the transmission pipeline. With gas-fired compressor motors, a small amount of natural gas is funneled from the gas stream at the suction side to provide fuel for the motor.

Reciprocating units increase the pressure of the gas stream by compressing or reducing the volume of the gas through the use of pistons within a cylinder similar to the pistons in a car engine. These compressors can be found on interstate pipelines' mainline systems, which need to compress gas volumes with greater pressure differentials. Storage facilities also utilize reciprocating compressors to inject gas supplies received from pipeline systems at pressures ranging from 500-1,000 psig, into storage caverns at pressures that can exceed 2,000 psig. Just like the motors used by gas-fired centrifugal compressors, a small amount of natural gas is taken from the gas stream to provide fuel.



Reciprocating Compressor Cylinder Assembly (machinerylubrication.com)[6]

[6] "Reciprocating Compressor Basics," *available at* http://www.machinerylubrication.com/Read/775/reciprocating-compressor (last visited Aug. 5, 2011).

Line pack

Line pack is the volume of gas in the pipeline at a given point in time. Pipeline operators use line pack to maintain system operating pressures while accommodating the system's highly variable load requirements.

Most gas supplies enter a pipeline system at a relatively even hourly rate, or about 1/24th of the total amount of gas per hour (4.17 percent per hour) for the entire day, also known as "steady-state" conditions.[7] On the demand side, deliveries rarely leave the system at an even hourly rate. Deliveries are not constant primarily due to variations in demand caused by inlet and outlet flow changes, non-performance of receipt or delivery points, scheduled or unscheduled maintenance, and compressor startups and shutdowns.[8] Flow conditions that vary over time are known as transient flow conditions. Depending upon the flexibility provided by the interstate pipeline within its tariff or contract with the customer, the hour rates for gas delivery could be 5 percent and even up to 8 percent per hour. These hour rates are equivalent to a 20 hour to a 12.5 hour day, or simply stated, the customer can take the entire scheduled and confirmed quantity of gas for the entire 24-hour gas day in as little as 20 to 12.5 hours. Managing these transient loads could not be done without actively managing system line pack.

In order to prepare for the upcoming gas day, the pipeline operator will increase system pressures by increasing the use of available compression horsepower at compressor stations strategically located along the pipeline system. The increase in pressure will allow the pipeline operator to "pack" the pipes with additional gas from other portions of the pipeline system located closer to the supply points. Further, depending upon demand forecasts for the upcoming gas day, customers will often increase their receipts in order to ensure that they will be able to meet their load requirements. Unlike electricity, which is added to the transmission lines instantaneously, natural gas must be physically moved through the pipeline from the supply areas to the market areas for delivery. Depending upon the length of the pipeline system, this physical transportation of gas from the supplier to the end user can take days. Most interstate pipeline systems move gas at speeds between 20 and 30 mph. If the pipeline has its origin in the Gulf of Mexico and the destination is the New York City market area, 1,500 miles away, the gas will need roughly two days to travel that distance

[7] Steady-state flow conditions exist when the gas volumes both received into and delivered out of the pipeline system are equal at every moment in time while the pipeline is operating at a constant pressure and temperature. For example, a pipeline is said to operate under steady-state conditions when 1/24th of the gas volumes are entering the system every hour while simultaneously 1/24th of the gas volumes are leaving the pipeline system every hour. Gas volumes going into the system must equal the gas volumes leaving the system to be considered steady-state conditions.

[8] Saeid Mokhatab, William A. Poe & James G. Speight, Handbook of Natural Gas Transmission and Processing 414 (Elsevier 2006).

at 30 mph. This is why it is critical for pipeline systems to receive gas supplies nominated, scheduled and confirmed in order to replace the system line pack in a timely manner.

Maximum Allowable Operating Pressure

The Maximum Allowable Operating Pressure (MAOP) is one of the many design assumptions that will limit either a pipeline's design capacity or peak day capacity. The MAOP, which represents the maximum pressure at which a pipeline may operate its system,[9] is an operational or safety-based constraint that protects the integrity of the pipeline system while defining an upper capacity limit. As such, the MAOP will act as a physical constraint[10] that the pipeline companies' system design engineers must address with each pipeline expansion project before the Commission.

When a pipeline company files an application to add a new service or to expand its existing facilities, it will look to the Commission's regulations (18 C.F.R. § 157.14(a)(7)-(9)(vi)) for guidance. Under these regulations, the pipeline company is required to provide to the Commission flow diagrams reflecting "Daily Design Capacity" and "Maximum Capabilities" for both its existing and proposed facilities. Currently, most of the interstate pipeline companies justify the need for facility augmentation through the use of a steady-state model of their respective systems while operating under design peak day flow conditions. These models are designed to meet the pipeline's firm contractual obligations while maintaining: (1) the volumetric requirements of its existing firm shippers; (2) the minimum contractual delivery pressure obligations; (3) controlling pressures located at critical points on their system; and (4) the full utilization of the existing available capacity through the use of all available compression horsepower along the path of the new service.

Implicit in the pipeline companies' design process is the need to maintain actual operating pressures at or below the MAOP in order to maximize throughput levels on their respective systems. From the design perspective, this is a relatively simple task. In most cases the pipeline's design capacity is based upon maximum utilization of compression facilities while transporting gas volumes between primary contractual

[9] In its November 14, 2002 comments in Docket No. PL02-9-000, the Office of Pipeline Safety (OPS) stated that the purpose of setting regulatory standards for determining pipeline MAOP is to "prevent pipeline failure that could result from excess operating pressure, startup and shutdown." OPS defines MAOP as the maximum pressure at which a pipeline or pipeline segment may operate. The Office of Pipeline Safety, Comments in Response to Open Forum at the Natural Gas Markets Conference Oct. 25, 2002, Docket No. PL02-9-000 at 4 (filed 11/14/2002); s*ee also* 49 C.F.R. § 192.3.

[10] Physical constraint, or pipeline bottleneck, is a point on a system where the existing facilities are inadequate to accommodate 100 percent of the flowing capacity of the upstream pipeline facilities.

receipt and delivery points. Under these specific design assumptions, maintaining operating pressures at or approaching the MAOP will ensure that existing shippers will receive their gas requirements.[11] However, as previously discussed, the changing load requirements and the capacity release market could potentially reduce the pipeline's ability to maintain optimum operating pressures to meet new demands on its system if the new loads are not proximate to the traditional markets. The potential impact of new markets could reduce the operational flexibility of the pipeline by reducing the operating pressure. If the pipeline cannot maintain historical operating pressures that are necessary to meet the requirements of its shippers, the throughput capacity of the pipeline will be reduced.

[11] Scheduled and unscheduled maintenance is not incorporated into the pipeline's design capacity. As a result, required maintenance will reduce the pipeline's ability maximize throughput capacity and could prevent the pipeline from meeting its firm contractual requirements.

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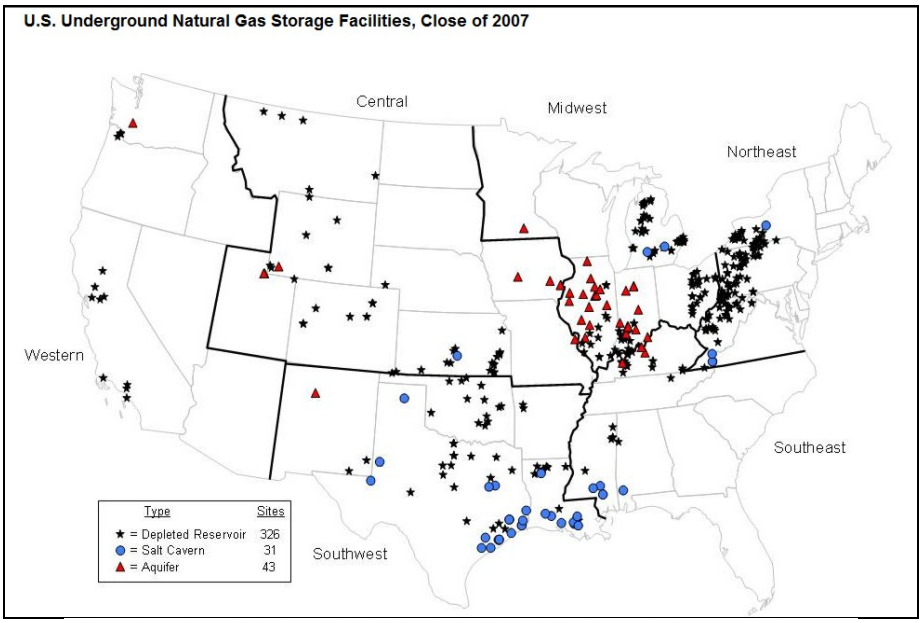
Appendix: Natural Gas Storage

Natural gas, like many other sources of energy, can be stored during periods of low use and called upon during periods of greatest demand. There are over 400 underground storage facilities, eight LNG import facilities and over 100 LNG peaking facilities located throughout the U.S.[1]



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division Gas, Gas Transportation Information System, December 2008.

Base load vs. Peak load Storage Facilities

Storage facilities are designed to meet either base load or peak load requirements. Base load storage is designed to meet seasonal demand that exceeds the average deliverability of the pipeline system. Base load storage facilities have sufficient capacity to meet the long-term seasonal demand requirements for the pipeline's market areas. Historically, these storage facilities were used by the pipeline's customers to inject natural gas supplies into the storage facility during periods of low system use, such as the non-heating season (when gas prices are low), which typically runs from April 1 through October 31. These gas volumes were then withdrawn to meet base load requirements during the heating season, which usually runs from November 1 through March 31.[2]

[1] United States Energy Information Administration, *About U.S. Natural Gas Pipelines – Transporting Natural Gas, available at* http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html (last visited July 20, 2011).

[2] This trend has changed in the last decade as newer and more efficient natural gas-fired electric generation facilities have replaced higher emission oil-burning facilities. As a result, more natural gas is needed during the spring and summer months to meet increased electrical demand for the summer cooling season. Now, instead of having one peak season, market areas served by some pipelines may have two peak periods, during both the summer and winter months.

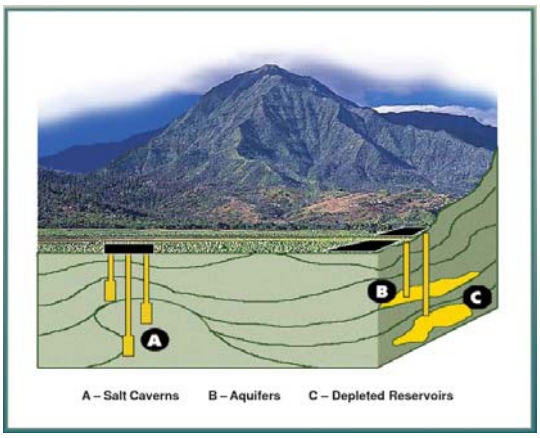
Base load storage facilities are usually large depleted oil or gas reservoirs that have relatively low withdrawal rates. They can provide a steady flow of natural gas and typically have turnover rates of once a year due in part to the length of time necessary to replenish the gas supplies. Depleted gas reservoirs are the most common type of base load storage facilities.

Peak load storage facilities, on the other hand, are designed to operate at high rates of withdrawal. These facilities are used to meet peak load requirements that can call for large amounts of gas over short periods of time. Peak load facilities are much smaller than base load facilities but can be quickly replenished – in some cases within days or weeks.

Different Types of Underground Storage Facilities

Three types of reservoirs or geological formations are used as underground storage facilities – aquifers, depleted reservoirs, and salt caverns. All of these formations must be developed or reworked in order to create the space necessary to provide the storage service. Natural gas is injected slowly into the formation through the use of compression facilities in order to build up the reservoir pressure necessary to allow the natural gas to flow freely from the storage facility directly into the downstream pipeline systems. Toward the end of the withdrawal season, when the prevailing reservoir pressures fall below the operating pressures of downstream pipeline systems, compression equipment that was used to inject gas volumes into storage is used to re-pressurize the gas stream so that gas from storage can be moved downstream into the pipeline systems.

Not all of the natural gas in storage facilities can be withdrawn. In order to maintain the integrity of the formation and to prevent migration of water into the reservoir, some natural gas must be left in the reservoir. This is typically called “base gas” or “cushion gas.” Similar to line pack in a natural gas pipeline, base gas is the volume of gas left in the reservoir to provide the pressure needed to extract the remaining gas. The gas that is withdrawn from the storage field is referred to as “working gas.” The amount of working gas within the reservoir represents the storage capacity of the facility.



Types of Underground Natural Gas Storage Facilities (FERC)

Depleted Reservoirs

Depleted gas reservoirs are the most commonly used formations for storage reservoirs. These formations are formerly producing gas reservoirs that have had all of the economically recoverable natural gas extracted, and which can be readily converted from production to storage. However, to maximize the usefulness of the facility, the reservoir should be located near a market area (for base load or peaking facilities) or a supply area, (to supplement supply when production is interrupted). The reservoir also must be located near a mainline pipeline facility. Most depleted gas reservoirs are located in production areas, leaving aquifers and salt caverns as the only option for storage development in other areas.

Aquifers

Aquifers are underground porous, permeable rock formations that act as natural water reservoirs. A porous rock formation has small spaces between the grains of rock where natural gas, oil and water can be found. A permeable formation is one where liquid can flow through small channels that connect the small pore spaces within the formation. Aquifers are the least desirable and most expensive types of natural gas storage facilities for the following reasons:

- The geological formations are not as well known as depleted reservoirs, which are explored during the development and production process. Accordingly, there is a significant cost associated with developing and studying the geological characteristics of an aquifer in order to determine its suitability as a storage reservoir.

- Aquifers do not have in place the facilities and equipment associated with a producing gas reservoir, such as extraction equipment, pipelines, dehydration facilities, and compressors. Aquifers may also produce large

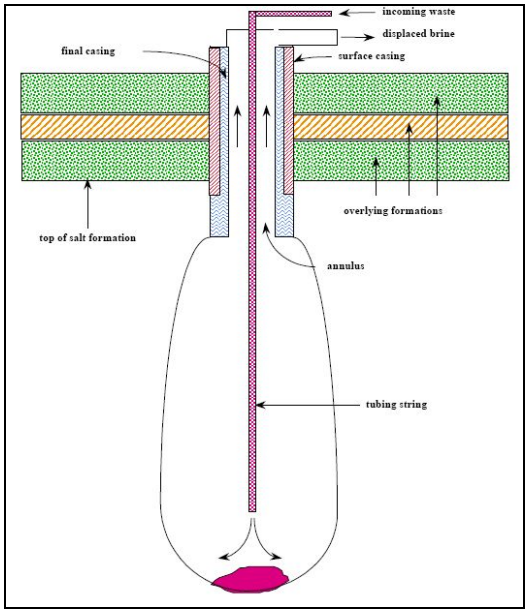
volumes of water as natural gas is withdrawn from storage, increasing costs.

- Development of an aquifer as a gas storage facility can take twice as long as development of a depleted reservoir facility.

Salt Caverns

A salt formation is a naturally occurring deposit of salt that may exist in two forms: salt domes and salt beds. Salt domes are formations that have migrated through sedimentary geological formations to form large domes of salt. These domes can be a mile wide and 30,000 feet thick. Salt domes most often used as salt caverns are generally found about 6,000 feet beneath the surface. Salt beds are not as thick or as deep – these formations are usually less than 1,000 feet thick and are less stable than salt domes, but both formations are well suited to natural gas storage.

Salt Cavern Underground NG Storage Reservoir
(Energy Information Administration)

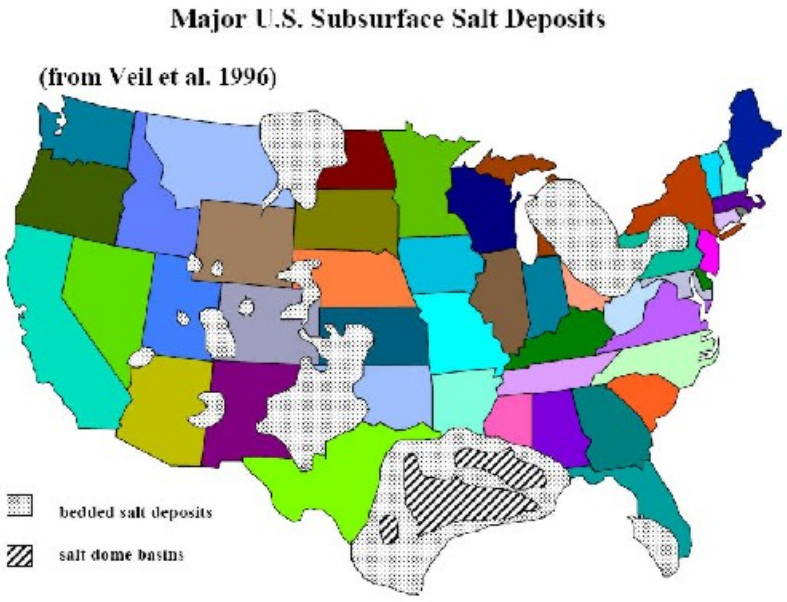


Salt Cavern Leaching
(Oregon National Laboratory)

Salt caverns are developed by drilling into the salt formation and circulating large amounts of water under high pressure to dissolve and extract the salt, leaving a large void. This process is known as "salt cavern leaching."[3] Once created, the salt cavern offers an underground vessel-like structure that can provide very high rates of delivery.

[3] Salt Cavern Storage, *What is Salt Cavern Storage? available at* http://www.saltcavernstorage.com/what-is-salt-cavern-storage.html (last visited July 20, 2011).

Salt caverns provide another operational benefit, in that they can operate with less base gas than depleted reservoirs and aquifers.



(Oregon National Laboratory)

Because salt cavern storage reservoirs are typically much smaller than depleted gas reservoirs, they cannot hold the volumes necessary to meet base load storage requirements. However, because the deliverability of the salt caverns is typically much higher, gas stored in these facilities can be more quickly withdrawn and replenished than gas stored in any other type of facility.

LNG and LNG Peak Shaving Facilities

Liquefied natural gas (LNG) is natural gas that is stored and transported in liquid form at -260 degrees Fahrenheit. In liquefied form, the gas volume is reduced by a factor of 610. This reduction in volume makes the transportation and storage of liquefied natural gas more practical.

In order to introduce LNG into the pipeline system, the LNG must be warmed and re-gasified. This is done at specially built re-gasifier terminals attached directly to the interstate pipeline grid or to LDC distribution systems.

LNG can also be produced on a much smaller scale at liquefaction facilities, which receive natural gas directly from the pipeline system, convert it to liquid form, and store it in above ground facilities until needed to meet peak load requirements. These facilities are referred to as “peak shaving” plants.

Appendix: Natural Gas Storage

LNG Peak shaving plant (Energy Information Administration)

Appendix: Natural Gas Transportation Contracting Practices

Interstate natural gas pipeline rates for transportation of natural gas may be based on distance transmitted (zone matrix) or on a "postage-stamp" basis, where all consumers pay the same rate regardless of distance transmitted. Natural gas pipelines' tariffs may contain rates based on a function of the volume reserved for a particular buyer (a set capacity charge) and a variable based on the pipeline volume actually consumed by the buyer (a commodity charge). Gas is sold by unit of energy, not by volume. Prices are usually stated in price per unit of energy, such as dollars per million British thermal units (Btu), rather than price per unit volume, such as dollars per thousand cubic feet (Mcf). Interstate natural gas transportation tariffs are often priced per thermal unit or energy unit, not on a volumetric basis.

The wholesale market is composed of both the natural gas commodity market and the transportation market. Since 1984, when FERC Order No. 436 was issued, large numbers of industrial customers, electric generators, and end use customers have been buying gas from parties other than the pipelines or LDCs. After the issuance of FERC Order No. 636 in 1992, the industry witnessed a dramatic growth in the use of marketers to provide gas, arrange transportation, or provide both services to LDCs, industrials, retail users, and electric generators.

Gas customers use marketers in a variety of ways. LDCs, which hold firm transportation rights on a single pipeline, can use the marketer to obtain and deliver gas to an interconnect point on that pipeline, and the LDC can use its firm transportation service to deliver that gas to its citygate delivery point. Other customers, such as industrials, may employ a marketer to acquire gas and interstate transportation service to deliver the gas to the industrial's citygate delivery point. Increasingly, marketers are offering additional services to customers such as asset management services, where the marketer manages capacity for LDCs, as well as providing price hedging, financing, and risk management services.

The transportation market also has developed to provide shippers with alternative means of acquiring capacity. Shippers can choose either short or long-term services from the pipeline or can acquire capacity from other shippers through the capacity release mechanism.

The use of released capacity has made possible the development of virtual pipelines. A virtual pipeline can be created when a marketer or other shipper acquires capacity on interconnecting pipelines and schedules gas supplies across the interconnect, creating in effect a new pipeline between receipt and delivery points not on a single pipeline company's system.

Nominations, Confirmations, and Scheduling

The North American Energy Standards Board (NAESB) is an independent, industry-supported entity whose primary purpose is to set business standards across the industry. The Commission's standards relating to nominating, confirming, and scheduling gas across the interstate pipeline system were developed by industry representatives in conjunction with NAESB. The nomination, confirmation, and scheduling processes control the movement of gas across the interstate pipeline system.

Nominations

A nomination is a request for service under any transportation agreement by a gas purchaser (referred to as the shipper) to transport gas from a specified receipt point to a specified delivery point over a specific time period. In short, a nomination is the request for space in a pipeline to ship gas. Pipelines use the nomination process to coordinate and reconcile gas from different shippers on their pipelines.

A shipper purchases capacity on a pipeline by entering into a service agreement with that pipeline. For example, a shipper may have a firm transportation agreement with Pipeline A for 100,000 dekatherms (DTH) per day of service. Since the agreement is firm in nature, as opposed to interruptible, the shipper pays for that full capacity whether it uses it or not, and has priority for that capacity on the pipeline.

On a given day, the shipper may not need the full 100,000 DTH of capacity, but might need, for instance, 75,000 DTH to meet its needs. The shipper will thus nominate 75,000 DTH for that day, and the pipeline can then schedule the unused 25,000 DTH of available pipeline capacity to another shipper as interruptible transportation.

The industry-standard gas day begins each day at 9:00 AM central time, and runs for 24 hours. In order to standardize nominations across the interstate pipeline system, FERC has implemented four time cycles where shippers may nominate gas (or change their nominations) over the course of each gas day. These nomination cycles follow the NAESB standards. While this is the minimum number of nomination cycles that a pipeline must have in its tariff, some pipelines offer more nomination options.

The first of the four standard nomination times is the "timely nomination cycle." Under the timely nomination cycle, shippers must make their nominations

by 11:30 AM the day before the gas is to flow. The pipeline will acknowledge receipt of the nomination by 11:45 AM and will issue its final confirmations by 3:30 PM and post scheduled quantities by 4:30 PM. Gas under the timely nomination cycle will flow at 9:00 AM the following morning, which is the beginning of the gas day.

The second nomination cycle – which also occurs prior to gas flow – is the "evening nomination cycle." Shippers must make their nominations for this cycle by 6:00 PM the day before gas flows, and the pipeline will acknowledge receipt of the nomination by 6:15 PM, issuing its final confirmations by 9:00 PM and posting scheduled quantities by 10:00 PM. Gas under the evening nomination cycle will flow at 9:00 AM the following morning. During the evening nomination cycle, the firm shipper can adjust his nomination to his full contractual capacity for the next day, taking precedence over, or "bumping," an interruptible shipper's nomination.

The two remaining cycles are known as intra-day nomination cycles, since they occur while gas is flowing during the same gas day. Under the intraday 1 nomination cycle, shippers must make their nominations by 10:00 AM on the gas day. The pipeline will acknowledge receipt by 10:15 AM, issue its final confirmations by 1:00 PM, and post scheduled quantities by 2:00 PM. Gas under the intraday 1 nomination cycle will flow at 5:00 PM on that gas day. The same bumping procedures apply to the intraday 1 nomination cycle. The intraday 1 nomination cycle is the first opportunity for shippers to adjust their gas flows during the gas day.

For the intraday 2 nomination cycle, shippers must make their nominations by 5:00 PM, and the pipeline will acknowledge receipt of the nomination by 5:15 PM, issue its final confirmations by 8:00 PM, and post scheduled quantities by 9:00 PM. Gas nominated under the intraday 2 nomination cycle flows at 9:00 PM on the same gas day.

Bumping rights do not apply to the intraday 2 nomination cycle. FERC implemented this no-bumping rule for the intraday 2 nomination cycle because shippers bumped this late in the gas day would be unlikely to be able to arrange alternative transportation.

Confirmations

Once a nomination is received by the pipeline or the party providing the requested service, the nomination must be confirmed. The confirmation process verifies that (a) the shipper agrees to supply the nominated quantity to the pipeline

for transportation, and (b) the pipeline agrees to transport the nominated quantity, based on the availability of capacity. The confirmation process provides a degree of assurance to the parties that gas will be delivered, and is also important for record keeping purposes.

Scheduling

For each nomination cycle, once the shippers nominate gas on a particular pipeline, it is the pipeline's responsibility to schedule the gas. Scheduling refers to the process by which nominations are consolidated by receipt point and by contract, and verified by upstream and downstream parties. If there is enough capacity to accommodate all nominations, then all nominated quantities will be scheduled. If the nominated capacity exceeds the available capacity on a pipeline, quantities will be allocated according to what is referred to as scheduling priorities. Shippers with a higher priority service will receive their capacity before shippers with a lower priority service.

Scheduling priorities for each pipeline are set forth in that pipeline's tariff. Although scheduling priority specifics may differ from pipeline to pipeline, all follow a general priority model. In general, primary firm shippers are given highest priority. Firm shippers are shippers that have entered into firm transportation agreements with pipelines. Firm shippers reserve a volume of capacity on a pipeline and pay for that capacity whether they use it or not. Each transportation agreement specifies a primary receipt and delivery point for service under the agreement. In some cases, the agreements may set forth multiple primary receipt and delivery points that can be used. When the shippers take service under the primary receipt and delivery points set forth in the agreement, they are considered primary firm shippers, and receive the highest priority of service.

In general, secondary firm shippers are given the second highest service priority. Under FERC policy, shippers may use receipt and/or delivery points for service other than the primary points set forth in their agreements, but only if capacity is available at those points. These alternate points are referred to as secondary points. In general, when a firm shipper takes service under secondary receipt and/or delivery points, that shipper no longer has the highest priority of service, but rather the second highest service priority. These secondary firm shippers get their gas scheduled after the primary firm shippers.

Interruptible shippers are generally given the third highest priority service. Interruptible service is service that is not guaranteed. Whereas firm shippers pay for the capacity whether they use it or not (and are given highest priority on that

capacity), interruptible shippers only pay for transportation capacity when it is used.

Pipelines implement various methods for allocating interruptible capacity. One method is to schedule interruptible nominations *pro rata*, whereby all shippers with interruptible capacity have a proportional share of their capacity scheduled. Another method is based on economic ranking, where shippers who pay more for their interruptible capacity receive priority over shippers who pay less. A particular pipeline's practices for scheduling interruptible capacity will be set forth in the priority provisions of its tariff.

Nominations and Scheduling on Intrastate Natural Gas Pipelines

The NAESB standards do not apply to intrastate pipelines, which follow their own scheduling practices. Only thirteen percent of the member companies of the Texas Pipeline Association that responded to an informal poll reported that they accept electronic nominations, and none indicated that they follow the NAESB standards.

In Texas, intrastate pipelines schedule gas transportation five days a week, with no weekend scheduling. Some intrastate pipelines do not schedule volumes at particular delivery points on their systems, but instead accept nominations from customers, typically LDCs, that can have hundreds of delivery points. These customers do not schedule volumes at a particular point, but submit a nomination that covers all of their points, with the right to obtain delivery at any of them.

The Commission requires major non-interstate pipelines to post scheduled volumes no later than 10:00 PM central time the day before gas is to flow. This deadline occurs after interstate natural gas pipelines are required to post their evening cycle schedule confirmations by receipt and delivery point.

Imbalances

A point imbalance is the difference between the volume of gas that is scheduled to flow at a receipt or delivery point, and the volume of gas that actually flows through the point (typically determined by meters). A transportation imbalance is the difference between net receipts under a specific agreement (total receipts minus any fuel receipts), and total deliveries made under a specific agreement. When an imbalance occurs on a pipeline system, the pipeline must resolve that imbalance to keep all parties whole. There is no single method pipelines use to handle system imbalances. Instead, each pipeline resolves

imbalances in accordance with the imbalance provisions set forth in its FERC NGA Gas Tariff.

Operational Balancing Agreements

An operational balancing agreement (OBA) is a contract between two physically interconnected parties specifying the procedures to be used in processing imbalances or differences in hourly flows between the parties. An OBA ensures that a shipper, once it has properly nominated and had its gas confirmed, will not be subjected to imbalance penalties resulting from the transfer of gas between the pipelines. In Order No. 587-G, the Commission adopted a requirement that each interstate pipeline enter into an Operational Balancing Agreement at all points of interconnection between its system and the system of another interstate or intrastate pipeline. That requirement is codified in section 284.12(b)(2)(i) of the Commission's regulations.

Impact of Cold Weather on Gas Production in the Texas and New Mexico Gas Production Regions of the United States During early February, 2011

Winterization Document

Prepared for Federal Energy Regulatory Commission

Prepared by Gas Technology Institute
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July, 2011

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Introduction

Colder-than-normal weather during the first week in February led to the biggest non-hurricane natural gas supply disruption in the United States since at least 2005.

Due to a combination of well freeze-offs (gas flow blockages resulting from water vapor freezing in the gas stream) and other temperature-related well failures, processing plant shutdowns, electric power outages, and pipeline operational issues, estimated daily natural gas production fell from about 62 billion cubic feet per day (Bcfd) to less than 57 Bcfd, a decrease of 8%. (Ref. 1)

The cold weather likely impacted thousands of natural gas wells in Texas and Louisiana, home to one-third of U.S. gas production. Because it rarely freezes in these southern U.S. latitudes gas wells aren't built to withstand the phenomenon called "well head freeze off." That's when the small amount of water produced alongside the natural gas crystallizes inside pipelines, completely blocking off the flow and shutting down the well.

In particular, along with the cold weather came severe icing conditions. Icy roads inhibited the movement of water hauling trucks in particular and the ability to access wellheads. The result was that fail safe switches on water and condensate storage tanks at wellheads and at compressor stations were activated. The fail safe switches are designed to shut down operations to prevent spills. (Ref. 2)

This report focuses on gas well winterization technology that is deployed in colder climates and discusses to what degree they might be applied to the impacted production areas (Texas and New Mexico) addressed with this study.

The Phenomena of Wellhead Freezing and Cold Weather Impact on Gas Production Operations

Freezing is a potential and serious problem starting at the production wellhead through the last point in the customer delivery system. The occurrence of freezing is continuously reduced each step of the way, but care must be taken at each and every step to assure smooth operational conditions and satisfied consumers at the end of the line. Freezing not only affects the wellhead and gas pipeline but is also a significant contributor to measurement errors, instrumentation upsets or failures and other regulation equipment that can be found at compressor stations, gas processing plants, regulator stations and other critical points of operation. (Ref. 3)

Many criteria can have an impact on the freezing issue including:

- Gas quality and composition
- Wellhead and wellbore design and configuration
- Piping designs, regulation or restriction points

- Instrument take-off points
- Other

Three areas will be reviewed as to the potential for freezing due to cold weather conditions:

1. The reservoir, wellbore and wellhead environment.
2. The gas well production facilities located at or near the wellhead.
3. The gas gathering system including compressor stations and gas processing plants.

Potential for Freezing - Within the Reservoir, Wellbore and Wellhead

Natural gas resides in geologic formations for time periods of millions of years (geologic time). Over this extended time period the gas becomes saturated with water. The volume of water that natural gas can carry as water vapor is a function of pressure, temperature and gas composition. Figure 1 is a schematic of a gas reservoir (Barnett shale in this example), its gas quality, reservoir conditions and gas flow pathway from the reservoir to the surface. The gas flows from the reservoir through perforations in the pipe (casing) and then up through the production tubing, through the wellhead and then to production facilities.

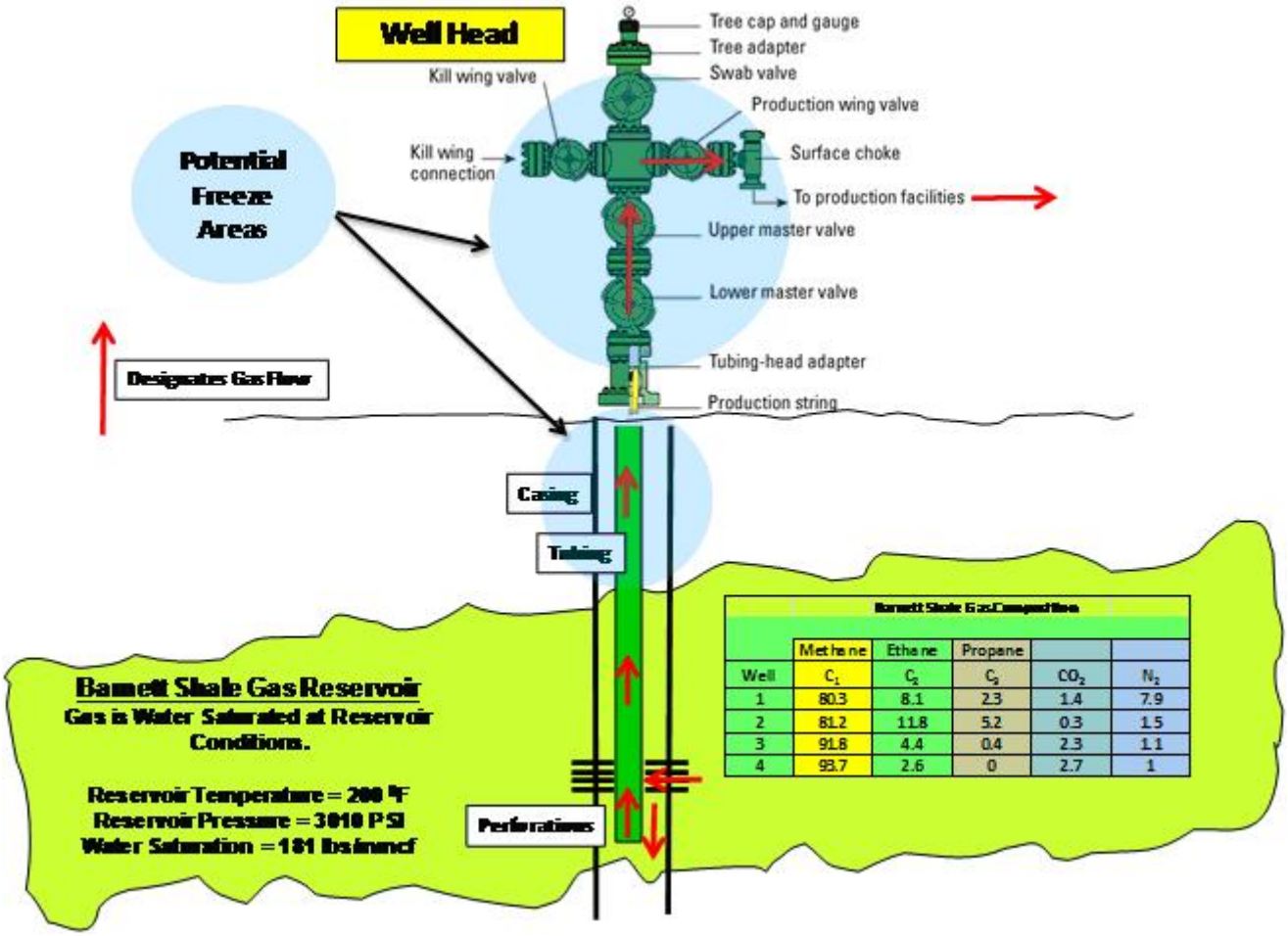

Figure 1 – Schematic of Gas Reservoir (Barnett Shale as example), wellbore and wellhead flow paths to Production Facilities, (Ref. 4&5) (Figure from GTI)

Under the Barnett example reservoir conditions the gas can hold as much as 181 lbs of water per mmcf of natural gas. For production operations, 7 lbs of gas per mmcf is considered to be dry gas, or at least dry enough for safe and efficient transportation of the gas without undo problems due to water fallout or freezing. Many natural gas compositions include not just methane CH_4 but also heavier hydrocarbons such as ethane and propane. In the Barnett example, the composition of well #2 contains over 11% ethane and 5% propane. The existence of these heavier hydrocarbons can facilitate the formation of hydrates (a combination of hydrocarbons and water that form ice under conditions well above freezing). Hydrates are discussed in more detail later but for this discussion can be thought of as ice capable of reduction or complete blockage of gas flow. (Ref. 4 &5)

As the gas flows up the production tubing and nears the surface it experiences a drop in pressure and can also be cooled by gas expansion (Joule Thompson effect) and exposure to cold ambient temperatures at the surface. The Joule-Thomson rule of temperature effect as a result of pressure reduction is such that temperature will decrease approximately 7 degrees Fahrenheit for every 100 psi

pressure reduction. As an example, if you can have gas flowing at 60 degrees Fahrenheit and 700 psi and you may have no evidence of freezing. If you pass through a flow choke and cut the pressure to 225 psi, the flowing temperature at the point of regulation will drop 33 degrees to approximately 27 degrees Fahrenheit. If the gas stream is saturated with water vapor and condensate, you will quickly experience freezing. The gas stream is the same, but conditions have changed and icing problems can impact your operations. (Ref. 3 &4)

The presence of ice or hydrates can not only shut off the pipeline, but can also alter measurement. If ice forms on the rim of the orifice plate, the flow measurement will be in error as a result of the reduced orifice diameter. If ice forms in the instrumentation supply lines, controllers will cease to function causing a loss of control of the system. Ice can block off sensing ports and other vital instrument readings. Once the ice begins to thaw, problems are still going to be present. On the initial start-up of a new or cold well, probes, intrusive instruments and orifice plates should have been removed from the pipeline. Large balls of ice traveling down the pipeline can do physical damage to the pipeline itself and to any object protruding into the pipeline such as sample probes, temperature probes, meters, orifice plates and similar intrusive devices. After the flowing stream has stabilized and temperature conditions are above the hydrate point, these items can be safely re-installed. (Ref. 3 &4)

The likely areas for icing and/or hydrate buildup and the typical solution for these problems as applied in cold weather climates are described in Table 1. See also Figure 1.

Table 1 – Points of Freezing Potential in the Reservoir, Wellbore and Wellhead (Ref.4)

Point of Freezing Potential	Cause of Freezing	Solution
Near Surface Wellbore	As the natural gas travels from the reservoir to the surface, cooling can occur due to gas expansion and exposure to colder temperatures near the surface.	Methanol is injected into the flow stream at the wellhead. The flow of methanol is down the wellbore annulus and then is carried up the gas flow stream through the wellhead preventing freezing.
Wellhead including Wellhead Valves	At the wellhead a change in flow path size can change causing an increase in velocity and cooling. Well head also exposed to surface weather conditions.	Solution is as above, methanol injection. In some cases the wellhead can be completely enclosed in a small building or “hut”, insulated and heated, but methanol is the most practiced solution.
Wellhead Chokes	Wellhead chokes are points at the wellhead where flow and pressure is primarily controlled. Significant pressure	As above with methanol application. Also, wellhead design should consider choke points and avoid wherever

	drop often occurs and expansion cooling can be severe. This cooling combined with cold ambient temperatures can cause significant freezing issues.	possible.

Potential for Freezing – Gas Well Production Facilities Located at or Near the Wellhead

The basic flow of natural gas from a wellhead through the processing equipment and to the gas sales distribution system is illustrated in Figure 2. Note that this is described as a typical configuration keeping in mind that variations to equipment placement and metering occur dependent upon the number of wells, their proximity to each other, well ownership and other factors.

Referencing Figure 2, when gas leaves the wellhead it sometimes flows through a line heater which will warm the gas, any gas condensate and water within the flow stream, mitigating freezing and facilitating the separation of these three phases. (Line heaters are not always deployed in warmer production climates unless large flow volumes requiring pre-heating before separation of phases are experienced). The flow stream next enters the production separator (sometimes described as a heater treater) where gravity, heat and flow through mesh material separate the gas condensate from gas and from water. The condensate and water flow to storage tanks through liquid meters in some cases, or alternatively volumes are measured directly within the storage tank. These liquids are marketed by truck or pipeline in the case of condensate and the water sent to disposal facilities by truck or pipeline dependent on volumes and distances.

The gas flow stream exits the top of the production separator and flows to the dehydration unit. It is noted that the gas, while free of liquid phase water and condensate at this stage, is still saturated with liquid vapors notably water. Gas flows into a dehydration unit for removal of water or dehydration of the gas, drying it to normally 7 lbs/mmcf or less allowing for transport without freezing and water fallout issues. The normal dehydration process utilizes glycol which absorbs the water from the gas leaving the hydrocarbons within the flow stream. The glycol when saturated with water is sent to a glycol reboiler that through application of heat boils off the water. The dry gas is now metered and flows to the gas gathering system. (Ref. 4&6)

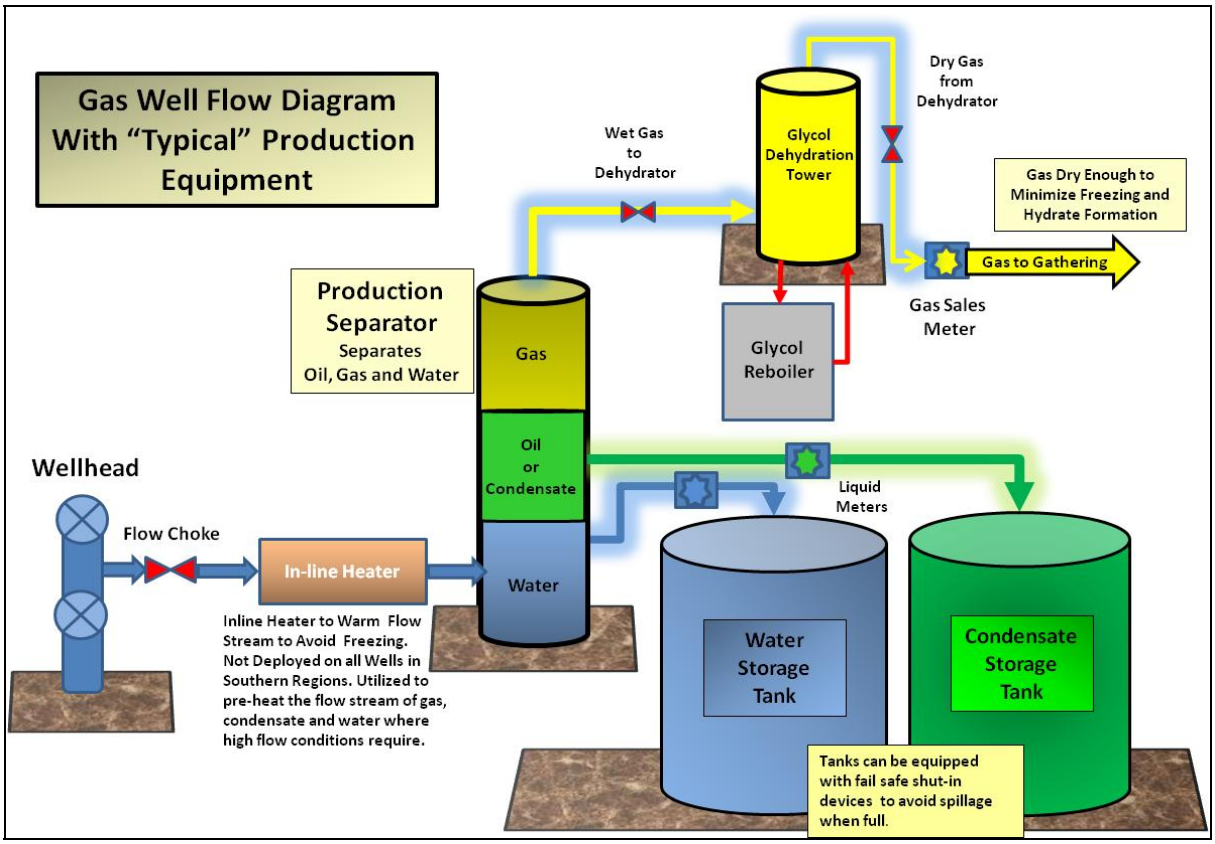

Figure 2 – Gas Well Producing Location with Typical Equipment for Gas Production Operations – Does not Include Gas Processing or Compressor Station. Production Equipment is Equipped with Fail Safe Devices to Shut-in Production to Avoid Spillage and Equipment Damage - (Ref. 4&6). (Figure from GTI)

The likely areas for icing and/or hydrate buildup and the typical solution for these problems as applied in cold weather climates are described in the following Table 2. See also Figure 2.

Table 2– Potential for Freezing – Gas Well Production Facilities Located at or Near the Wellhead. (Ref. 3, 4&6)

	Cause of Freezing	Solution Utilized in Colder Gas Production Regions
Flow lines from wellhead to line heater. If no line heater (common in warmer regions)	Exposure to low surface temperatures, gas has cooled due to expansion, gas contains water and heavier hydrocarbons which are prone to freezing or hydrate development.	Methanol injection, line heating, maintaining level flow lines to avoid liquid build-up, and limit choking points. Additional protection is usually required including insulating

then flow line to separator.		flow lines, wrapping with heat tape or glycol tubing under the insulation.
Production Separator	The production separator has equipment and instrumentation that can be impacted by cold weather. Gas, water and condensate flow throughout the unit. It is exposed to surface temperatures.	The unit is sometimes placed in a heated housing unit or hut. Alternatively, a cold weather version needs to be utilized. The cold weather unit is designed such that all piping and potential freeze instruments are internalized to the unit or insulated.
Gas Flow lines to Dehydration Facilities	If exposed these lines, which are still carrying water saturated gas and other hydrocarbons are prone to freezing and hydrate formation. This can take place in a particularly exposed portion of the line or at a bend or reduction in line size.	Sometimes these lines can be buried if it is some distance to the dehydration facility. This alone may not be adequate and insulation and heating may be required. A methanol injection point can be designed into the flow scheme if a particular area becomes a problem.
Flow Line to Sales Meter and Meter	The gas flowing to the sales meter has now been dried and is much less prone to freezing. The gas however can still be comprised of ethane and higher hydrocarbons as well as CO2 or N2 or other constituents. Depending on conditions of T & P Hydrates can still form despite dry (water content) gas.	Hydrate control can be achieved through application of heat, housing the meter and protecting from weather, methanol injection and other techniques described for managing wet gas freezing.
Condensate and Water Lines and Storage Tanks.	The lines to the storage tanks are at low pressures and the water is usually brine so freezing and hydrates are not as much of an issue. Depending on fluids and climate however some freezing can occur. If this takes place in the flow lines it can disrupt the separator causing production shut-in.	These lines can be insulated or in severe conditions heated with electric tape or glycol tubing. The tanks themselves do not normally present a problem.

Potential for Freezing - Gas Gathering System Including Compressor Stations and Gas Processing Plants.

After natural gas leaves the wellhead and wellhead production site it continues flow downstream through the natural gas system (Figure 3). Along the way, gas compression is required to maintain pressure and gas processing is applied to further dry the gas and remove heavy hydrocarbon components. Each is discussed further in this section.

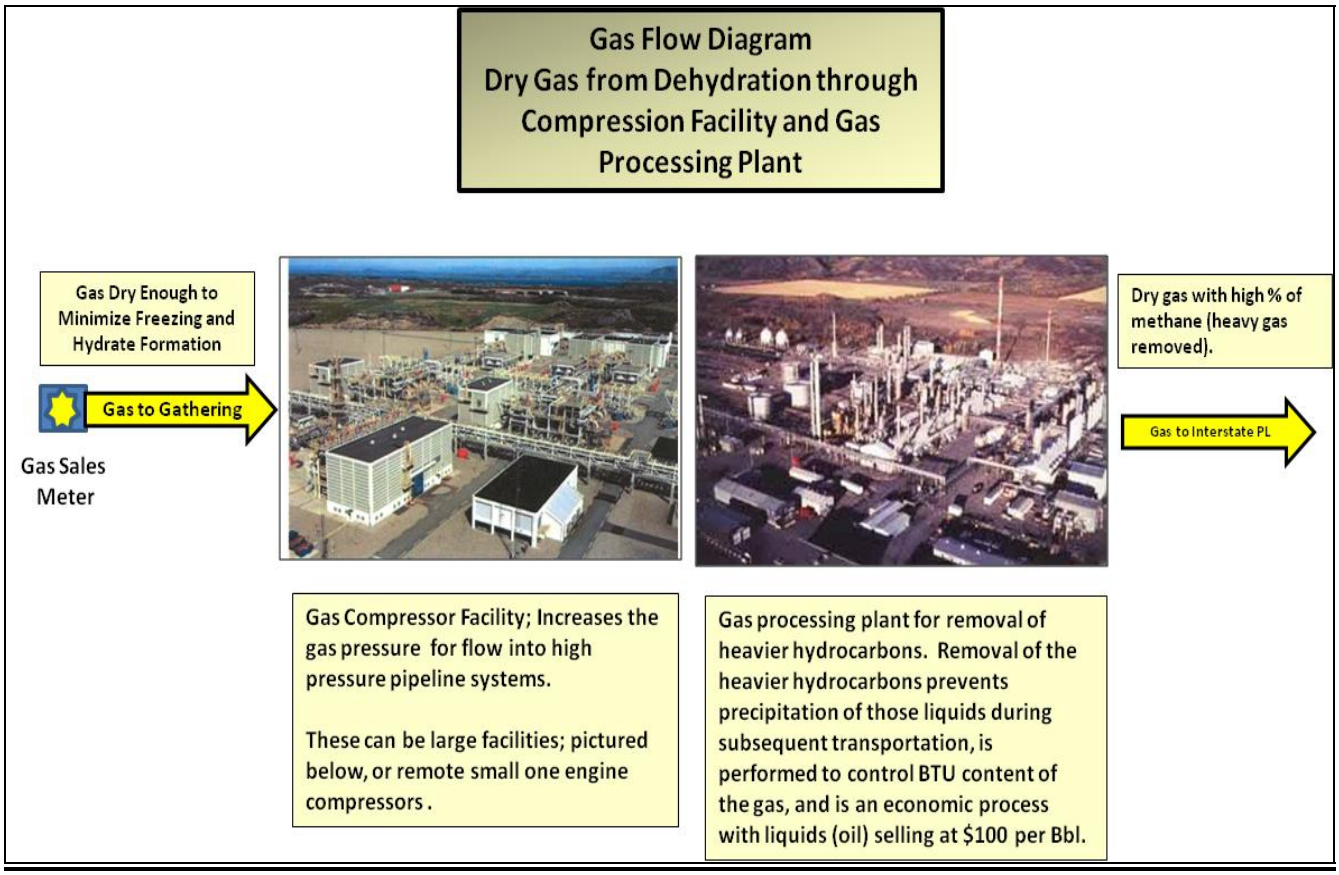

Figure 3 – Gas Flow Diagram – Dry Gas from Dehydration Facilities through Gas Compression and Gas Processing Plant. (Figure from GTI and ABB Oil and Gas and Duke Energy Canada)

Compression - After the natural gas stream leaves the dehydration facility it will at times flow through a compression facility or single compressor. The purpose of this is to boost the pressure of the gas such that it is able to flow into a sales line that is at higher pressure. The natural gas industry utilizes a large number and wide variety of compressors. Overall greater than 45,000 compressors are in place in the United States (Figure 4) (Ref. 7).

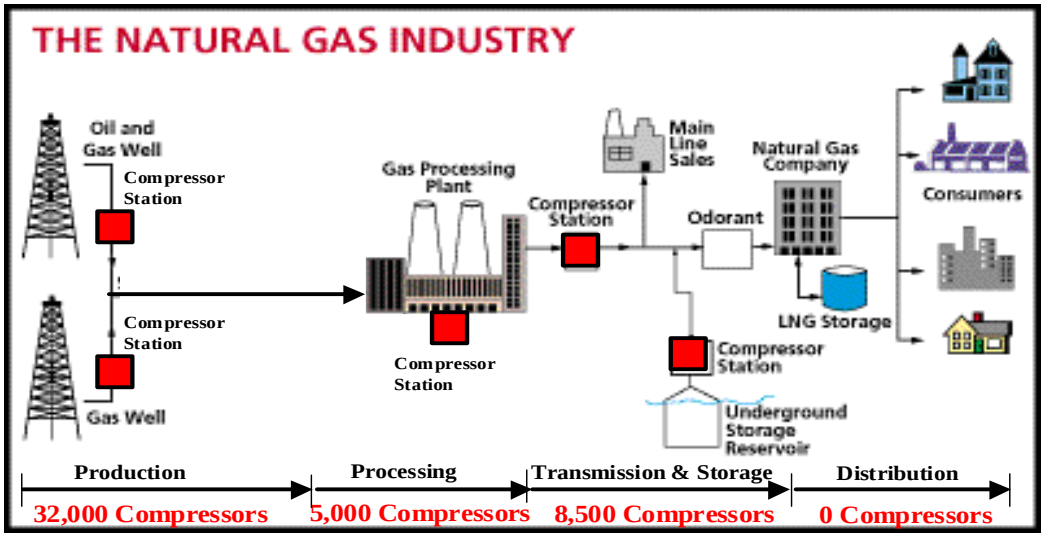

Figure 4 – Natural Gas Compressors in the U.S. Natural Gas System (Ref. 9) (Diagram from Wikimedia Commons)

Compression facilities range from small single compressors to large facilities handling large volumes of gas at aggregation points. The compression facilities within a producing gas field will change with time due to several factors:

- The drilling of new wells over time introduces increased gas volumes in a gas producing region.
- Existing wells will decline in gas production volumes over time reducing gas volumes.
- Gas flowing from the wellhead is initially at high pressure but then declines as gas is produced. This decline can be very rapid for the newer gas shale wells being developed, requiring compression facilities to be installed at appropriate points to keep wells flowing.
- The older well flow rates (at low pressure) will be reduced by the high pressure new wells in the absence of compression facilities. It is under these circumstances that new and sometimes remotely located compressors are installed.

The overall effect of these changing conditions is that compressors may need to installed, removed or resized based on the many factors impacting their size and number requirements.

The impact of cold weather on compressor stations can vary. Compressors stations all have safe guard instrumentation that senses temperature, pressures and flow rates. If pressure, as an example, gets too high or too low, the compressor will shut itself down to prevent expensive damage. These instrumentation processes can be impacted by cold weather. In colder climates, compressors can be housed to protect against any severe weather conditions (Figure 5). The majority of these compressors are fueled by natural gas as it is readily available due to it being the medium being compressed and transported. (Ref. 4, 7, 8)

Compressor stations take low pressure gas and increase the pressure significantly which is accompanied with temperature increases of the gas flow stream. Changes in pressure and temperature will cause additional liquids to drop out of the gas stream. The temperature and pressure conditions can vary considerably at these facilities. Some of the variables and conditions involved include:

- Pressure changes can occur; pressures can be dropped to manage the inlet pressure conditions to the compressor. High pressure and low pressure wells may be feeding the inlet side of the compressor. These well pressures are brought into balance at the inlet section of the compressor by dropping some well pressures to balance with the low pressure wells.
- The drop in pressure can cause gas cooling (Joule Thompson effect).
- Increasing pressure through the compression facility can cause gas heating.
- Temperatures and pressures are monitored throughout the compressor system and automatic shut down devices will be activated if they deviate from a defined range (too high or too low).
- Many of these changes can cause liquids (water and condensate) to condense from the gas stream and need to be removed and stored in nearby storage tanks.
- The storage tanks must be emptied on a regular schedule or fail safe shut-in devices will activate.

In urban areas (Dallas Ft. Worth as an example) electric compression is sometimes required due to noise limitations or emissions constraints. These facilities in particular are subject to any reduction in electric power due to weather or other conditions. There are some electric compression facilities in the Ft. Worth area but not in large enough numbers to have significant impact on gas production. (Ref. 4, 7, 8, 9)

Figure 5 - Fully enclosed, insulated and heated compressor; for cold weather environments. The unit offers metering, separation, and compression, all on one skid. (Photo Wikimedia Commons)

Larger compressor facilities are located at gas aggregation points where larger volumes of gas are compressed to higher pressures. These can be complex facilities with extensive piping, metering, and instrumentation. Cold weather can impact these facilities similar to smaller, more remote facilities. The incentive to weatherize however is greater at these locations due to the size and gas flow rates they address. There is an economic incentive as well as a reliability of service incentive to maintain flow at these aggregation points. The technology is readily available for winterization of these facilities and is commonly applied in colder regions of the country. As with the wellhead and production sites, the weatherization approach is a combination of heating important components via electric supply or warmed liquid flow (glycol), insulation of components, housing critical portions of the facility, injection of anti-freeze type chemicals (methanol), drying of the gas flow components, drying instrumentation gas via desiccants or other drying medium, or a combination of these techniques. (Ref. 4, 6)

Gas processing plants function to remove heavier hydrocarbons from the gas stream. These include ethane, propane, butane and others. There are three factors that drive the gas processing business:

1. The need to control gas heating value (BTU). Gas going into most end use functions (residential, commercial) requires gas within a certain BTU range which is often a narrow window around 1000 BTU/Ft^3 of gas.
2. For gas to be transported long distances through interstate pipeline systems it needs to be relatively free of heavier hydrocarbons. The heavier constituents will eventually precipitate during the pressure ups and downs encountered during long distance transportation. They then form liquids inside of the pipeline causing an unwanted pressure drop, freezing (through hydrate formation) or other interference.
3. With high oil prices, liquids are more valuable than natural gas. Therefore an economic incentive exists to remove the heavier hydrocarbons and sell into the liquids market as opposed to keeping them in the gas phase and selling based on BTU value alone.

These plants can be very complex (Figure 6) with extensive piping, processing units, regulators, instrumentation and other components. Many of these components can be impacted by weather conditions and to assure ongoing processing plant operation must be protected against weather. (Ref. 4, 10)

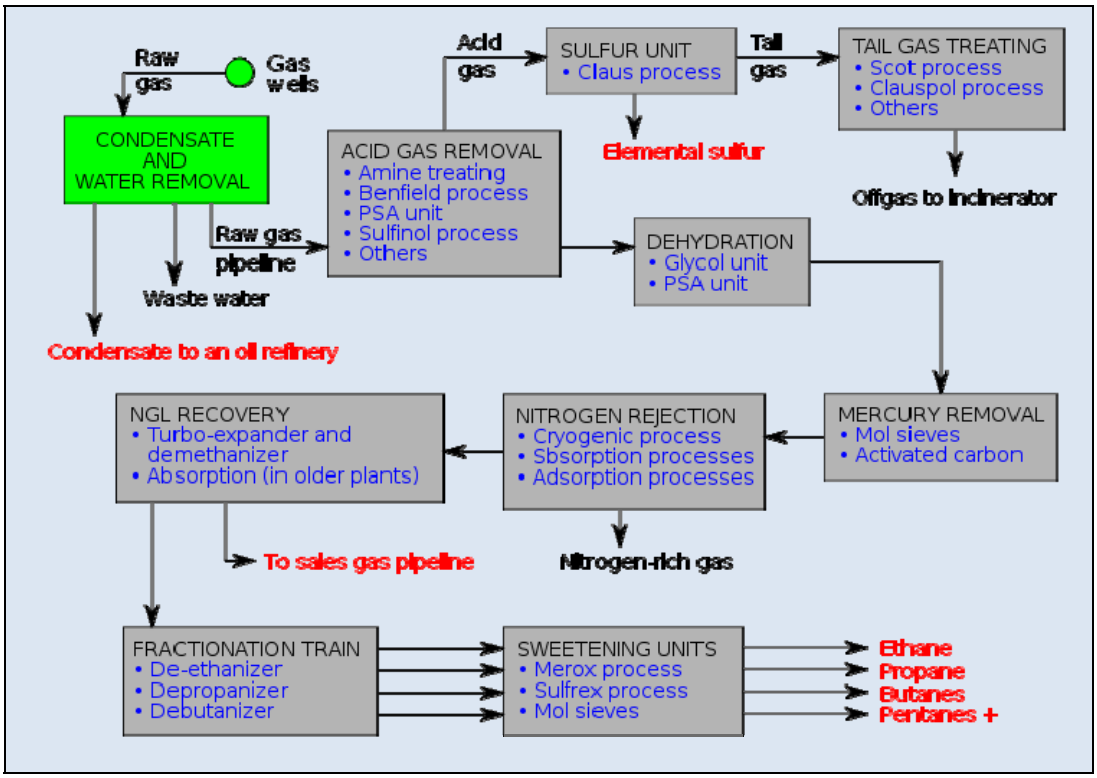

Figure 6 – Flowchart for a Gas Processing Facility – Illustrates the Complexity of the Process and the many Steps that can be Required. Levels of Complexity vary from Plant to Plant based on Need. (From ABB Oil and Gas).

Gas processing plants operate in cold weather climates along with other gas production facilities and as such, winterization equipment and processes are well known. It is a matter of frequency of events (cold weather) and the amount of time the facility is impacted, vs. the cost and time to winterize. Some processing plants have adequate piping and flow schematics to bypass some processes that might be impacted by cold weather. (Ref. 10)

Prevention of Wellbore, Wellhead and Production Facilities from Freezing – General Discussion and Description

There are several options for the prevention of freezing problems. Many of these are practiced on a regular basis in the colder regions of the country, to a lesser extent in the Mid-Continent region of the United State and not at all (in many cases) in Southern regions of the country. In order to correct freezing problems that occur under differing operational conditions, solutions must be designed for the particular needs of the location where the problem exists. Protection against freezing requires deployment of one or more mitigation techniques. Each of these techniques requires and investment in capital and operating expenses. The application of these techniques is usually determined by the

need or frequency of use along with the consequences (loss of production for a certain time period) of not utilizing.

In Southern regions of the United States, cold weather can be infrequent and when it does occur, can be limited in duration. A consequence is that the investment in freeze protection equipment and operations can be limited. The consequence to the producing life of a well can be minimal compared to the investment for cold weather operations in that lost production occurs for several days from a well with 20-30 years of operation life. On the other hand, if the level of impact is similar to the events of early February, 2011 and occurs on a more frequent basis, there can be a detrimental impact to the overall natural gas industry, as lack of reliability and accountability can result in loss of market. (Ref. 4)

Described below in general order of frequency of use are several techniques that can be applied to prevent freezing in gas operations:

1. **Methanol Injection to Prevent Freezing** - Methanol (an anti-freeze type solution) injection is a very common practice for freeze protection of wellbores and pipelines where wet gas flow occurs. Injection down the annulus of a wellbore by chemical injection pumps is utilized in production facilities in cold climates and in many gas storage operations where reliable, high flow rates in cold weather is required. The same technique can be practiced within a pipeline system and production facilities. The methanol is injected into the gas stream by chemical injection pumps or enters the pipeline by methanol drips and effectively lowers the freeze point of the gas. The amounts of methanol required can be calculated by using available tables for specific applications.

   A small volume methanol tower can also be fabricated allowing small volumes of gas to pass through the methanol for treatment. Because of the sensitive nature of many pneumatic controllers, this method is occasionally used to prevent freeze-ups in these devices and to prevent liquid migration into small orifices and passages. An additional filter is often used to ensure that the methanol is not carried over into the instrumentation. (Ref. 4, 11)

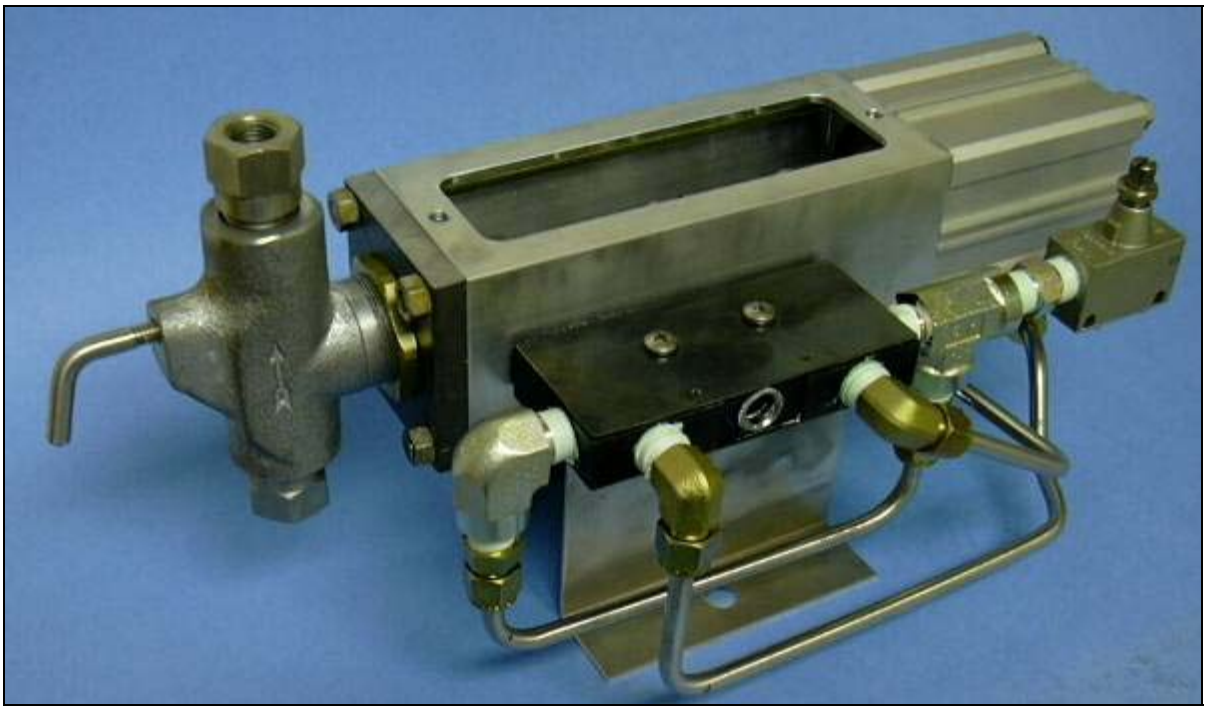

Figure 7 – Methanol Injection Pump Utilized to Inject Methanol into a Wellhead and/or Flow line to Prevent Freezing and Hydrate Buildup. Usually Located in Protected Housing on the Gas Well Location. (Ref. 11) (Photo Source ZKO Oilfield Industries; PTAC.org)

2. **Buildings or "Huts" to Enclose Production Equipment and other Weather Sensitive Equipment**
   Buildings are often constructed to house weather sensitive equipment in cold weather. This can be the preferred method for protecting production equipment and is widely applied in colder climates. The housing can be heated by catalytic heaters and can be insulated as needed for the extremes of weather conditions anticipated.

   Figure 8 is a typical setup for a Midwest Gas Storage Field (Manlove Gas Storage Field near Champaign, IL). The green fiberglass housing structure protects metering and other production equipment from freezing. Heating devices of various types can be utilized within the structure. Methanol chemical injection pumps are housed within the structure. During gas withdrawal operations (winter conditions) methanol is injected into the wellbore to prevent freezing. The wellhead itself is not enclosed. The wellhead is left open to allow for workover rigs to access the wellbore for any type of downhole maintenance required. Also, the heating of the wellhead may not preclude the formation of gas hydrates down in the wellbore some distance. This requires methanol injection as described in #1 above (Ref. 4, 12)

Figure 8 - Fiberglass Housing Surrounding Production Equipment at Gas Storage Field in Midwest United States (Ref. 12) (Photo credit Wikimedia Commons)

3. **Water Removal from the Gas Stream by Glycol Dehydration.** Gas dehydration is practiced on all natural gas flow systems to enable flow of gas without problems of hydrate formation, freezing, water drop out, corrosion and other issues. One of the most common methods of dehydration for large volumes of gas is glycol absorption. Gas passes through the glycol inside a vessel called a contactor (See Figure 2). The object is to remove the water to a point where the water vapor dew point of the gas will not be attained at the highest pressure and lowest temperature of the pipeline system. The glycol absorbs water and is then treated by circulating the glycol to a regenerator and distilling the water out of the glycol. The reconditioned glycol is returned to the contractor and the procedure is repeated. This process can reduce the water dew point to 60-70 degrees Fahrenheit. Colder climates frequently dictate a dehydration system in a natural gas system, but even warmer climates may require central dehydration due to pressure, temperature and gas composition. A producer can basically look at three dehydration options.
    a. Partial dehydration at the well head and later additional steps to meet contract specifications.
    b. Chemical injection at the well head with later dehydration at the central delivery point.
    c. Full and complete dehydration at each and every well head.

The glycol dehydration system is a low cost system with continuous operation and minimal pressure loss across the unit, thus making it a preferred approach in several areas of operation. The drawbacks can be glycol carry-over during surges, contamination by solid particles and inefficiency during fluctuating flow rates. (Ref. 4, 13)

4. **Heat Application for freeze protection** - Heat is a logical solution to freezing problems. It is also a costly approach to the problem for several reasons. Obviously, if the gas is never allowed to reach freezing temperatures, ice cannot form and will not be present. The water will likely not be removed, which remains an issue for operations and contracts, but the freezing is eliminated. The problems with heat are that it is expensive equipment to install, it requires additional fuel (energy and revenue) to produce the heat, and the heat will not remain effective as it travels down the pipeline and away from the heat source. Heat is also a potential hazard as it can provide an ignition point for the gas. Safety and special emphasis on proper application is a must when using a heat source. The most common application of heat for freeze protection is in a specific and direct situation, as in the case of a regulator valve body. The pressure drop at the regulator is the only problem point and therefore, can be the only specific location where freeze protection is required. There are multiple ways to apply heat from heating blankets, to catalytic heaters, to fuel line heaters, or in some cases, steam systems where they are properly designed, installed and maintained. Heat systems can be very effective for a localized freezing problem. Heat application coupled with insulation is a common technique for protecting flow lines in northern climates. (Figure 11). (Ref. 3)

Figure 9 – Gas Wellhead with Insulation on Flow line to Protect Freezing. (Photo Courtesy of ABB Oil and Gas)

5. **Combination of Techniques are Often Utilized –** A combination of winterization techniques are often required to fully protect a gas well production facility. Figure 10 illustrates a typical installation for a cold climate.

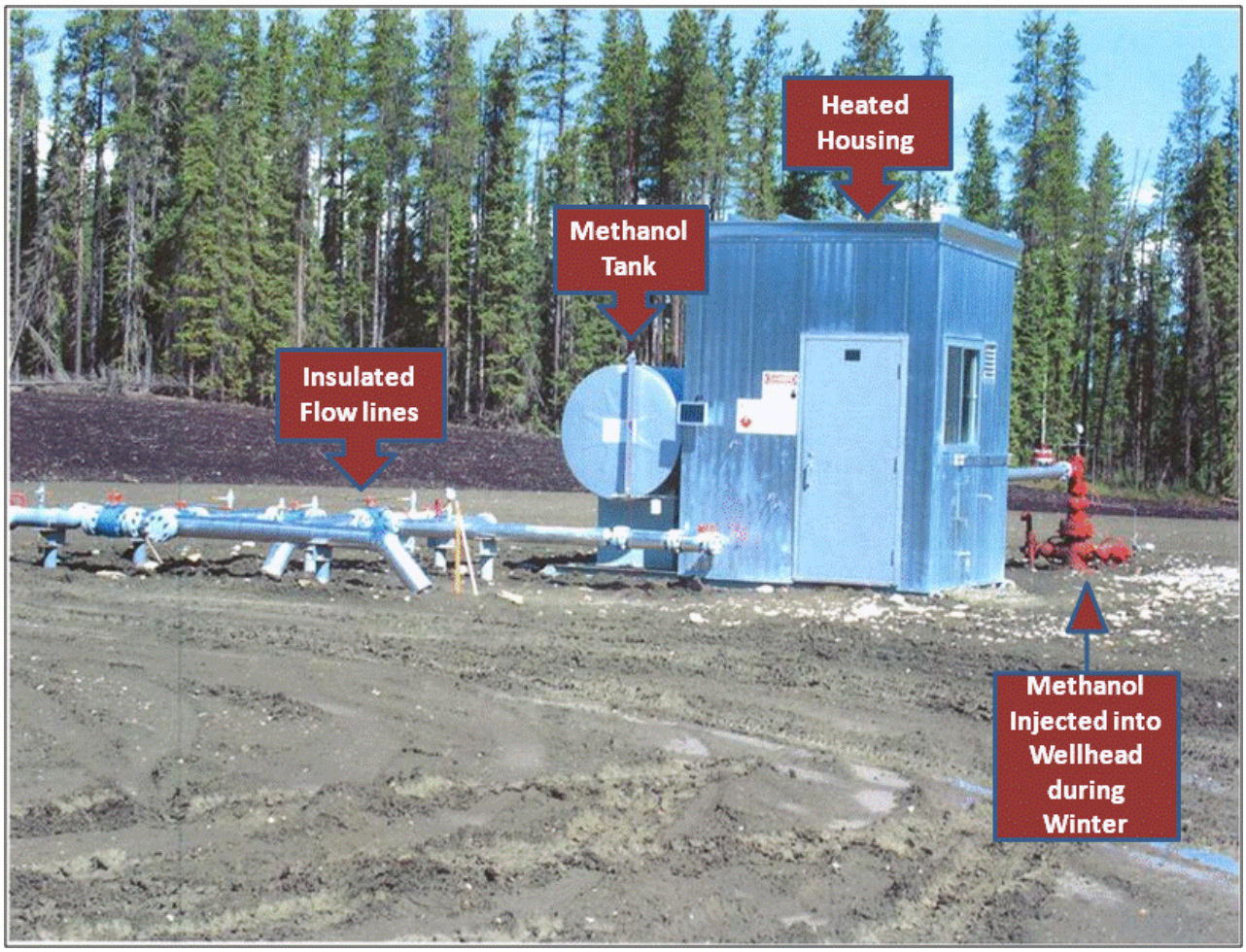

Figure 10 – Gas Production Wellhead and Production Equipment in Northern Region of United States Winterized for Cold Weather Operations. (Photo Source ZKO Oilfield Industries; PTAC.org and modified by GTI)

Referencing Figure 10, the following equipment and steps are practiced for flow assurance in cold weather climates:

- Flow lines are insulated.
- All wellheads are set up to inject Methanol which is done throughout the cold months.
- Assurance that flow lines are level, avoiding low spots where water can accumulate.
- Utilization of gas fired line heaters ahead of the production separators to keep all fluids warm enough to avoid freezing prior to separation of gas, gas condensate and water phases (See Figure 6).

- All flow lines beyond the production separator are insulated and heat traced. This is accomplished by electrical heat tape when electricity is available. Where there is no electric service, glycol tubes for circulating glycol are utilized to maintain flowing temperatures.
- Minimizing flow chokes is also practiced wherever feasible. Flow chokes are notorious Joule Thompson freeze points.
- Fiberglass huts over the wellheads are sometimes considered but difficult to accommodate due to impediments to accessing the wellbore for work-over and other considerations. (Ref. 3, 4, 6, 11)

6. **Pipeline Pigging** - Pigging in the maintenance of gas pipelines refers to the practice of using pipeline inspection gauges or 'pigs' to perform various operations on a pipeline without stopping the flow of the gas in the pipeline (Figure 11).

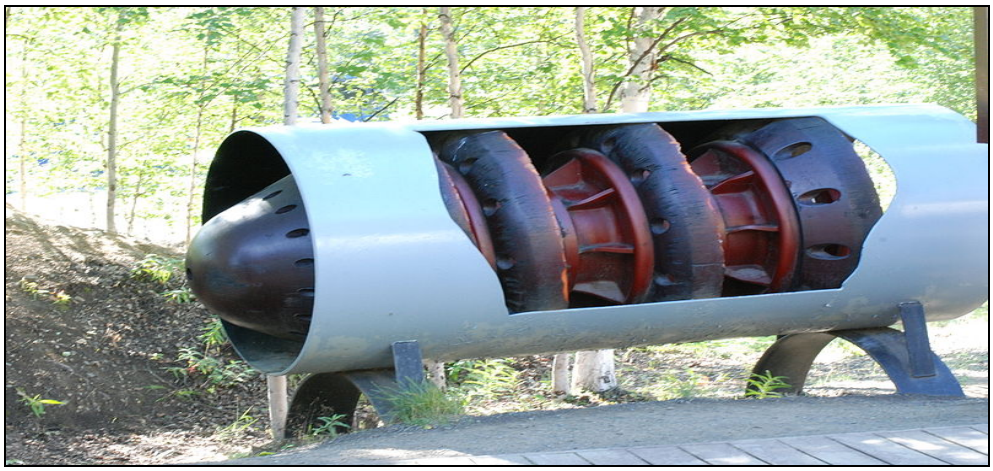

Figure 11 – Pipeline Pig Inside of Cut out Section of Pipeline (Photo Credit Wikimedia Commons).

These operations include but are not limited to cleaning and inspecting of the pipeline. This is accomplished by inserting the pig into a 'pig launcher. The launcher / launching station is then closed and the pressure of the product in the pipeline is used to push it along down the pipe until it reaches the receiving trap - the 'pig catcher' (Figure 12). (Ref. 14)

Figure 12 – Pipeline Pig Launch and Receiving Station (Photo credit Wikimedia Commons).

If the pipeline contains butterfly valves or other restrictions in line diameter the pipeline cannot be pigged. Pigging has been used for many years to clean larger diameter pipelines in the oil industry. Today, however, the use of smaller diameter pigging systems is now increasing in many areas to maintain pipeline flow integrity.

Pigs are also used in gas pipelines where they are used to clean the pipes, but also there are "smart pigs" used to measure pipe properties such as pipe thickness and corrosion. They usually do not interrupt production, though some natural gas can be lost when the pig is extracted. Most of the pigging operations are deployed in the gas gathering, transmission and distribution portions of the gas system as opposed to the wellhead production areas where pipeline configurations and sizes do not allow for pigging operations.

Pigging operations are conducted on a year around basis as needed to keep pipelines in working flow conditions. During cold weather their deployment can be increased due to additional liquids fallout and due to increased flow rates during cold weather. (Ref. 14)

7. **Practical Piping and Equipment Construction Considerations for Freeze Protection** - During the design phase of the piping and the instrumentation system, certain steps can be taken to reduce the negative effects of freezing problems. Piping configurations that would allow for liquid accumulation should be avoided if at all possible. Drainage should slope towards drain fittings located at low spots. Where possible, use ball valves and large diameter tubing for instrument feed lines and sensing lines. Avoid restrictions where flow will occur. Limit choking points. Tubing runs should slope back toward the pipeline and you should have a leak free

instrument system. Liquids, if they are present, will be drawn towards the leak. If you avoid creating traps and liquid drop out areas, your freezing problems will be minimized. (Ref. 3, 4).

8. **Other Water Removal Techniques for Cold Weather Protection, Especially for Instrumentation**
    a. **Solid Absorption -** A very efficient method of water removal is the dry bed or molecular sieve method. The gas is passed through large towers of solid particles and the molecular sieve absorbs the water very aggressively. Very dry gas over a wide range of flow rates can be attained by this method. Eventually, the sieve becomes saturated and must be regenerated. The stream must be switched to a second tower and hot gas is introduced to the original unit to evaporate the water and dry the sieve. Cool gas is then used to cool the desiccant and the tower is ready for re-use. This cycle is repeated until the desiccant has degenerated and is no longer effective. While this method produces very dry gas and has several positive operating characteristics, it is more costly than typical glycol systems and more complex to operate. If the gas contains heavier hydrocarbons they can sometimes interfere with the sieves.
    b. **Drip pots, coalescers and automatic liquid dumps can reduce freezing problems on instrumentation** - Occasional slugs of liquid can damage or even "shut in" many instrument supply systems. Where this slug potential exists or in cases where liquid is a severe problem in the gas supply used for instrumentation, drip pots and coalescers can effectively knockout or reduce the water and condensate in a small volume instrument supply system. If the problem is excessive, an automatic liquid dump designed for instrumentation can be extremely helpful. Whereas the drip pot requires routine manual draining, the automatic liquid dump will act as a drip pot collection vessel with a coalescer and as a result of an internal float assembly and pivot valve, will automatically release the collected liquid to a lower pressure point.
    c. **Instrument filters designed for freeze protection to control equipment** - Many instrument controllers and other sensitive measurement equipment powered by instrument gas supply need the highest level of clean and dry instrument supply that is attainable. In some cases a good linear polyethylene filter can provide adequate protection. But the most common solution for instrument supply gas is the filter dryer. These units are designed for high pressure applications with removable media cartridges. While various types of media are available from molecular sieve to special H2S removal media, most are equipped with a combination desiccant and charcoal filter cartridge. Coupled with providing extremely dry and fresh gas, the ancillary filtration elements in the cartridge provide for 2-4 micron protection as well. (Ref. 3, 4).

Natural gas systems, from mainstream pipeline flow to low pressure instrumentation, are subject to freezing conditions. Figure 10 is contrasted with Figure 13 where a non winterized location is illustrated.

Through careful planning and evaluation of a specific application, proper selection of available options, and a good routine maintenance program, this industry wide concern can be controlled and minimized. The cost of dealing with the aftermath can be more expensive than the preventative action that could have been taken.

Figure 13 - Typical wellhead in Warm Climate. (GTI) No methanol or other injection equipment for freeze mitigation. Flow line is elevated without insulation of other protection from cold weather. Tank battery and other production equipment are not protected from cold weather. (Ref. 4)

Alternatives to Cold Weather Control Techniques

Emissions of natural gas and other greenhouse gases are under increasing scrutiny as the concern about global warming continues to grow. Natural gas can be emitted to the atmosphere in many locations along the gas system. The gas industry has taken steps to mitigate these releases and continues to do so. Gas dehydration facilities are one step in the process where some gas is emitted. The dehydration step is required to remove water vapor from the gas stream to allow for safe and efficient transportation of the gas, and in particular to avoid gas line freeze-up when weather conditions turn cold.

One alternative to gas dehydration is the continuous injection of methanol into the system from the wellhead to a point of aggregation of the gas where it can be dried to pipeline specifications. This practice would eliminate the need for many individual dehydration facilities and thus the gas emissions. This is relevant when discussing flow assurance under cold weather conditions as well. The

injection of methanol could have the additional impact of avoiding freezing conditions within the gas flow system. This mechanism is practiced in the offshore environment where long pipelines transport oil, gas and water to onshore facilities for processing. Application of this technique onshore however, is often hampered by the many different mineral owners involved with each well. Each mineral owner has a royalty interest in the well allowing him a percentage of the revenue generated. This requires that a gas sales meter be installed to measure his appropriate share prior to mixing the flow volume with another well. Accurate gas measurement requires dry, liquid free gas leading to dehydration facilities at most wells. In the offshore environment there is only one royalty owner, the Federal Government. (Ref. 4, 11)

Discussion of Gas Hydrates Formation

Gas hydrate formation, also known as freezing, is a potentially serious problem in natural gas flow lines starting at the production well all the way through to the customer delivery system. The effective inhibition of hydrate formation, especially during cold weather, is essential for producers and transmission companies if they are to maintain a continuous supply of natural gas. Methods to control freezing range from removing water from the gas stream to lowering the water's dew point by injection of chemicals such as methanol.

Natural gas hydrates are ice-like substances that form through entrapment of hydrocarbon molecules inside the lattice of ice crystals. Hydrate crystals are formed under certain pressure and temperature conditions where the temperature may be above the melting temperature of ice. Many types of hydrates can form based on the presence of various gases. These include methane, ethane and propane hydrates, carbon dioxide and nitrogen hydrates and others.

Hydrates are very complex systems and their formation and dissolution remain a topic of ongoing research. They are known to exist in nature and form frequently within natural gas flow systems from the wellbore through the distribution systems for natural gas. They have been known to plug pipelines in the Gulf of Mexico for thousands of feet shutting in flow from multiple production platforms and significantly interrupting gas supply. In the Gulf of Mexico, where flow lines lay on the ocean floor in deep, cold water, and where the flow through the pipelines includes oil, gas and water prior to separation at onshore facilities; hydrate formation is a threat throughout the year. The solution to this problem is simply to inject methanol and other chemicals that inhibit hydrate development. This is performed as an ongoing operation and continues to be practiced. Research continues to better understand and control the formation of hydrates under these conditions, but today the application of methanol is the only effective solution. (Ref 4, 16)

Figure 14 – Hydrate Photos – Inset is the Water- Methane Hydrate Structure (Ref. 16, 17) (Photo Credits National Energy Technology Center (DOE) and Wikimedia Commons)

Figure 14 is comprised of two hydrate photos, one illustrating the melting of hydrates with the associated release of methane which has been ignited. It is through this phenomenon that the term "burning ice" is often used when describing hydrates. The smaller inset figure illustrates the hydrate cage formed by water and methane.

Methane hydrate, much like ice, is a material very much tied to its environment—it requires very specific conditions to form and be stable. Remove it from those conditions, and it will quickly dissociate into water and methane gas. A key area of basic hydrate research is the precise description of these conditions so that the potential for occurrence of hydrates in various localities can be adequately predicted and the response of that hydrate to intentional, unintentional, and/or natural changes in conditions can be assessed.

Figure 15 illustrates the combination of temperatures and pressures (the phase boundary) that describes hydrate formation conditions. When conditions move to the left across the boundary, hydrate formation will occur. Moving to the right across the boundary results in the dissociation (akin to melting) of the hydrate structure and the release of free water and methane.

In general, a combination of low temperature and high pressure is needed to support methane hydrate formation. Note that depending on the ambient pressure, methane hydrate can form at temperatures well above the freezing temperature for water; for example at 2500 psi pressure, the ice-like methane hydrate will form at 65 ^{o} F.

Heavier hydrocarbon gases and other gases such as carbon dioxide can form hydrates at higher temperatures and lower pressures than methane. Hydrates may form in wet natural gas streams containing high percentages ethane, propane, CO_2 and H_2S where no methane hydrate is formed.

Referring to Figure 15, note that the phase line for CO_2 and ethane are to the warm side of the methane phase boundary indicating that under a given pressure CO_2 and ethane hydrates form at higher temperatures. (Ref 4, 16, 17)

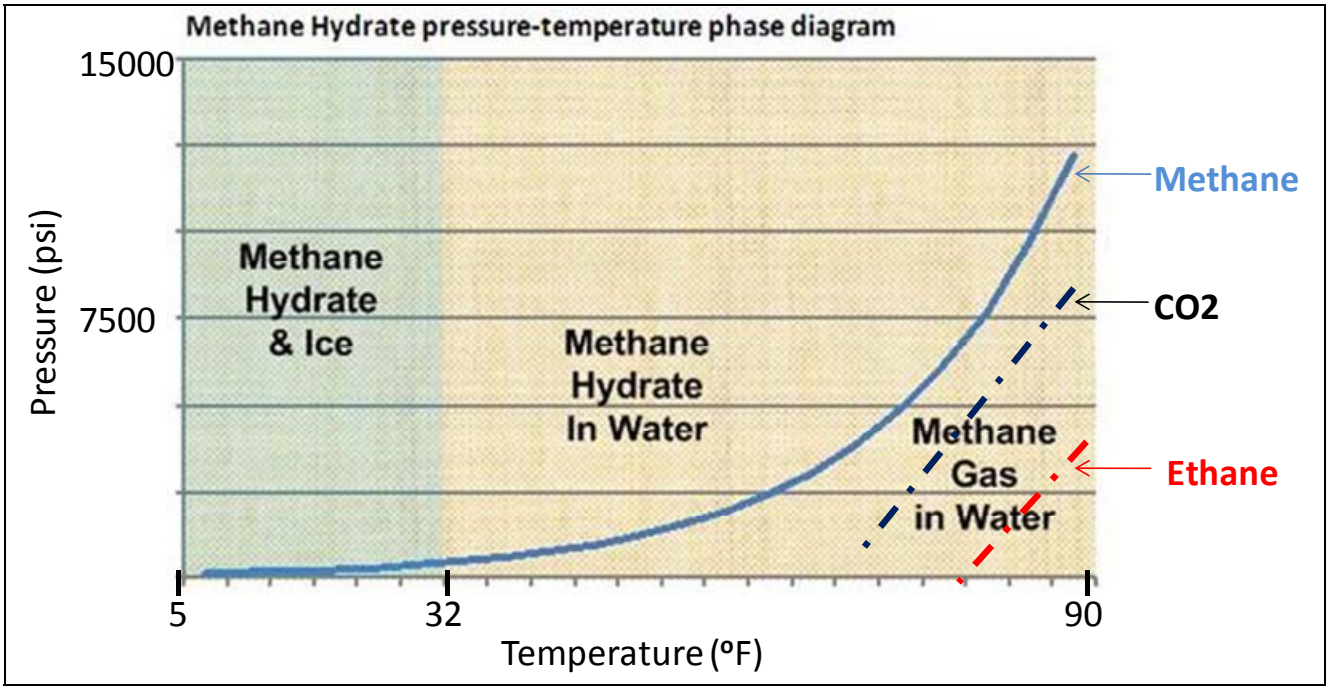

Figure 15 - Methane Hydrate Phase Diagram (Diagram Modified from Physical Chemical Characteristics of Natural Gas Hydrate).

The control of hydrates as previously discussed is accomplished in the same manner as for the control of icing conditions; application of heat, drying of the gas or chemical injection. With hydrates however it must be noted that they can form in somewhat dry gas especially if heavier hydrocarbons are present.

Gas Quality Considerations and Gas Processing

New technology has enabled the development of many new and significant shale gas plays in the United States including the Barnett, Marcellus, Eagle Ford, Fayetteville and others. The quality of the gas from these shale resources is different in each area requiring different approaches to production and gas processing. The volume of ethane, propane, carbon dioxide, nitrogen and other constituents vary considerably from play to play and can vary considerably within a single shale area such as the Barnett.

The gas processing industry has scrambled to keep up with the growth of the Barnett shale. Gas production has increased to 4 Bcf/day from near zero in 1999. Major gas processing plants have been constructed by Devon, Quicksilver, Enbridge and others. Most of the plants include compression, CO_2 treating with amine units, Cryogenic separation and fractionation. The process gas moves east toward Carthage, Texas where it can reach the Midwest markets via various hubs or it moves Southeast via the Transco or Florida gas pipeline. The gas processing plant typically process large volumes of gas. Within the Barnett region, plant capacities can range from 35 mmcf/day increasing to 1.0 bcf/day. Given the size of these plants, the volume of gas processed, the investment and sophisticated processes and equipment they are likely better able to withstand weather changes and disruptions due to rapid declines in temperature. When they do occur the problems can be identified and resolved. Unlike individual well locations the scale of these operations can justify winterization equipment and processes even for infrequent events. (Ref. 4, 5)

Table 3 – Barnett Shale Gas Compositions (Ref. 5) *Oil and Gas Journal*, March 9, 2009, Compositional Variety Complicates Processing Plans for U.S. Gas Shales.

Barnett Shale Gas Composition					
	Methane	Ethane	Propane		
Well	C_1	C_2	C_3	CO_2	N_2
1	80.3	8.1	2.3	1.4	7.9
2	81.2	11.8	5.2	0.3	1.5
3	91.8	4.4	0.4	2.3	1.1
4	93.7	2.6	0	2.7	1

Table 3 illustrates the gas composition from 4 wells from the Barnett shale producing area. As can be seen the compositions vary considerably. These changes and levels of gas constituents across the Barnett region have the following impact on gas production with respect to cold weather:

- The presence of the heavier hydrocarbons establishes a higher probability of hydrate formation even after the gas stream has been dried to 7 lbs/mmcf.

- There is the potential for liquids fallout with the heavier gases that may be accelerated during cold weather. This condensation may occur without hydrate formation.
- The heavier liquids provide an economic incentive along with high oil prices to establish gas processing plants to remove liquids.
- The presence of CO_2 and N_2 require that these waste gases be removed or blended with other gases to bring their percentage levels down to pipeline specifications.

In general the variation in gas composition adds complexity as compared to a dry gas producing region. The complexity consists of additional gas handling, processing, transportation, blending, metering and other operations that potentially can be impacted by cold weather. The exposure of this additional equipment to weather can impact the reliability of gas flow under conditions not normal for an area. (Ref. 4)

On the other hand, independent of the heavier hydrocarbons, gas shale production has all of the issues associated with water production and methane hydrate formation. There is the possibility that these conditions alone are enough to cause disruption during cold weather spells and as such the presence of heavier hydrocarbons may have limited additional impact. (Ref. 4)

What needs to be determined is the impact of cold weather on gas processing plants which are established solely for heavy gas removal. They being located at aggregation points can disrupt large volumes of gas flow when problems occur. Alternatively they are large complex facilities, located in a contained area (as compared to wellheads spread across many miles) which combines to provide both the incentive and opportunity for cold weather control technology.

Discussion of Cost Implications to Winterize Gas Wells – Per Well Cost and Per Field Cost

Recent technology development has enabled the recovery of gas from shale formations around the U.S. and now around the world. Unlike offshore platforms or large flow volume conventional gas wells, many wells are required to recover gas from low permeability gas fields. Gas well spacing requirements can reach down to one well per 10 or 20 acres in some cases. In the Barnett area typical spacing is one well per 40 acres and over time greater than 14,000 gas wells have been drilled over a 12 county area (Figure 10). This development took place in stages over a 10 year period as a better understanding of the full potential developed.

Another factor regarding gas fields with a large number of wells is the time required to respond to an event that impacts every wellhead. Within the time frame of the recent cold weather event it would have been impossible to attend to each of 14,000 wellheads, most at a different location to alleviate freezing and/or other cold weather issues. (Ref 4, 18)

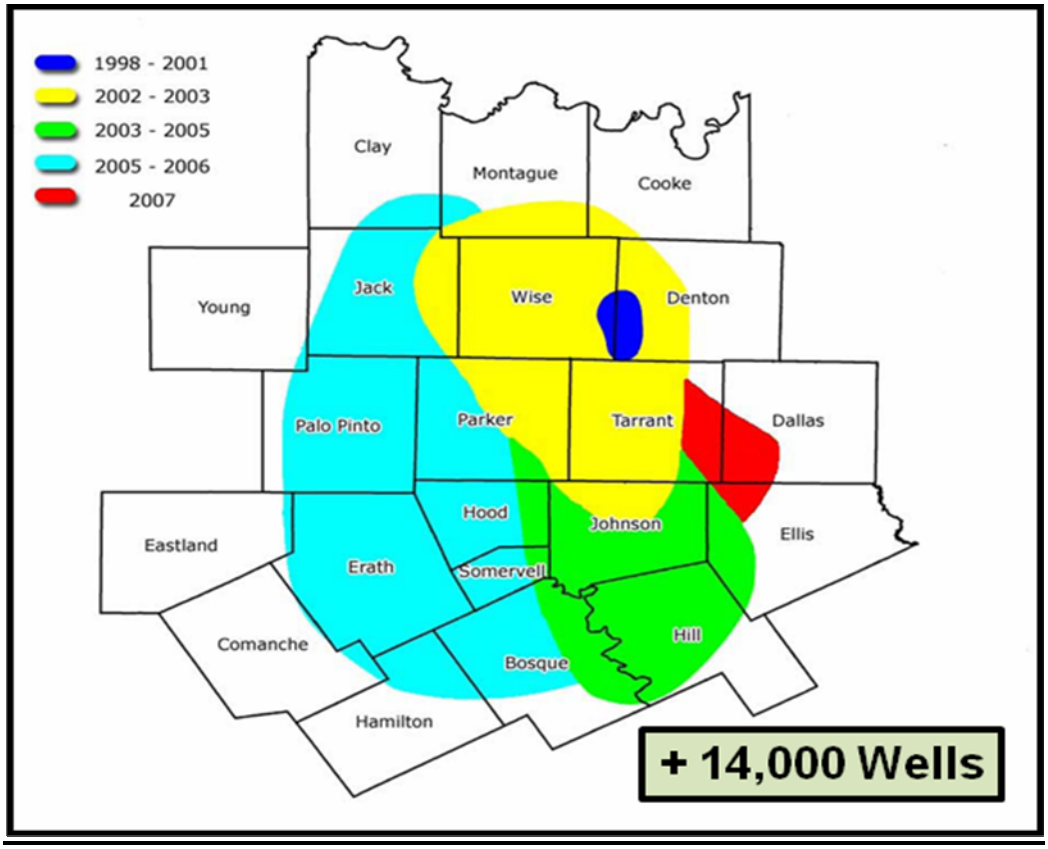

Figure 16 – Barnett Shale Gas Development Area near Dallas, TX, (Ref. 18) (Figure Courtesy Perryman Group – HART Unconventional Gas Conference).

The implications for cold weather flow assurance is that unlike the ability to winterize a large volume of gas flow at a single well location with a single investment, unconventional gas development requires winterization of many locations at practically the same capital expense.

Winterization of a gas well requires both capital expenditures and annual operating expense. Table 6 identifies the cost per well of these items.

In Northern regions of the country this equipment is normally part of the original well design and installed as a matter of necessity along with all other production equipment. On wells that can cost well in excess of $1 million each, these costs are not as significant as when compared to a retrofit after the well has been placed on production. This investment needs to be weighed against the impact and ramifications of the reduction in gas flow, power reductions and outages during this time period. (Ref 4, 19, 20)

Winterization cost of a wellhead or associated production equipment can varying considerably based on the size of facilities to be winterized, location, weather conditions, gas quality and other criteria.

Some approaches can be relatively simple with other facilities requiring more elaborate winterization equipment. Several scenarios based on conditions are described below with discussion of cost.

- **Case 1 - Cost Analysis for Simple Methanol Injection Pump and Hookup**

In some areas, possibly in many locations in the warmer climate production areas in Texas and New Mexico, a simple installation of a methanol injection system to be utilized during cold weather spells may be effective. Unlike northern climates where severe cold is experienced throughout the extended winter, the warmer production regions may not require significant equipment installation. If problem areas or key producing facilities are identified they may be protected with a simple investment.

A methanol injection and solar powered pump system can be installed for a capital cost of approximately $2,800 per installation. The systems are designed to reduce maintenance and operation expenses. Methanol costs are $12.00 per mmcf of gas throughput based on a treating ratio of 3 gallons of methanol per mmcf at a cost of $4.00 per gallon. Based on a well producing 1 mmcf per day of gas, methanol costs would equal $12 per day. On an annualized basis assuming methanol injection for 5 months the methanol cost equals $1800. Labor is estimated at $1000 per month or $5000 total. (Ref. 15)

Capital Cost = $2800 per installation.
Operating Cost for 5 months cold weather = $6800.

- **Case 2 - Cost Analysis for Building to Enclose Production Equipment**

In some cold weather climates the most efficient approach to winterization is to house the susceptible equipment in a small building or hut. This can sometimes save on more expensive approaches while at the same time protecting all equipment from year around weather conditions. These buildings can be heated with specialized heating equipment or in many cases can be warmed simply from the heat given off by the production equipment itself (assumes a heated production unit is within the building). In cold weather climates the design and construction of the production equipment includes the insulated housing, all of which is skid mounted for portability. When managed in this fashion the additional cost for winterization can be negligible compared to total well cost. Building cost can vary according to size requirements. This may be an option for critical equipment in the Texas, New Mexico producing regions.

Building cost = $2500 to $10,000

- **Case -3 - Cost Analysis for Equipment to Winterize Gas Wellhead in Very Cold Climate e.g., Canada (See Figure 10).**

In very cold production areas such as Canada, several winterization techniques need to be applied including methanol injection, line insulation, a small hut to protect chemical injection pumps small heaters, and methanol storage. The total cost of this installation is estimated at $34,425 per installation (see itemization below). (Ref. Table 10) Operating cost for a 5 month period is estimated at $6800 the same as Case 1.

Table 4 – Winterization Equipment Cost for a Gas Well Located in a Cold Climate

Equipment		Description		Cost
Winterized Production Unit - Net Cost for Winterization		Production unit winterized by internal piping and insulation.		$23,000
Timberline solar powered methanol pump w/solar panels				$2,800
Chemical Pump to Supply Chemical Inhibitors		Chemical Inhibitor Pump for Corrosion Protection		$1,350
Vent Gas Bottle to Supply Heater		System to Collect Vent Gas from Injection Pumps to Supply Heaters		$675
Methanol Tank		Stores Methanol		$1,000
Methanol Injection Tubing - High Pressure - $5/Ft - 100 Ft		Methanol Transfer		$500
Flow Line Insulation - $3/Ft - 100 Ft		Insulate Flow Line		$300
Flow Line Heat Tape - $4/Ft - 100 Ft		Provide Heat to Flow Line		$400
Fiberglass Hut for Enlcosing Production Equipment		Weather Protection		$1,500
Catalytic Heater for Location Housing		Heating for Hut		$500
Installation Cost - 2 men for 3 days at $50 per hour.		Labor		$2,400
Total Capital Cost per Well				**$34,425**

- **Case 4 - Cost Analysis for Equipment to Winterize Gas Wellhead Equipment Including Gas Production Unit**

In areas where a gas production unit is required to remove liquids (water or condensate or both) from the production stream a gas separator must be installed. The cost of a separator can vary based on

size which is dependent on the total flow volume to be handled by the separator. In warm weather climates the piping and instrumentation for the separator is installed externally to the unit as freezing is not an issue. For cold weather climates all of the piping needs to be internalized where heat from the production unit itself, in addition to insulation where required will prevent freezing. The additional design requirements, locating of piping and instrumentation in a confined space can add as much as $23,000 to the cost of a production unit. (Ref. 20) A less expensive option in some cases can be as described in Case 2 where all of the production equipment is housed in a small building or hut. These insulated buildings often require no additional heat beyond what is supplied by the heating unit in the production separator itself. (Ref 21)

- **Case 5 – Installation of Additional Storage Capacity at Critical Facilities**

During the recent cold weather spell in Texas and New Mexico many wells and compressor facilities were shut-in by automatic fail safe shut down devices that were triggered by tanks filling up with liquids. The fail safe shut-in devices protect against tank overflow and spillage. For critical facilities such as central compressor stations, gas processing plants or important well tank batteries, additional storage could be installed to allow for operations during bad weather conditions. Additional tanks are relatively inexpensive when compared to the impact of significant gas flow reductions.

Total Cost Discussion

The cost estimates for winterization can vary considerably based on the type of facility, the number of installations being considered, the degree of cold weather protection that is required, gas flow rates, pressures and other factors.

Simple weatherization such as for Case 1 above can be accomplished for an estimated $2800 capital cost and $6800 annual operating cost.

More comprehensive winter protection can increase the capital cost to over $11,000 per installation.

Winterization of production units, if required can add an additional $23,000 per installation depending on production unit size.

Overall, the cost of winterization, given the number of wells can be considerable. The simple table below illustrates cumulative capital cost with variable well counts and per well equipment costs.

Table 5 – Cumulative Cost for Winterizing Gas Wells – Variable Well Counts and Individual Well Equipment Cost.

			Well Count		
	10,000	20,000	30,000	40,000	50,000
Cost per Well			Cumulative Cost		
$2,500	$25,000,000	$50,000,000	$75,000,000	$100,000,000	$125,000,000
$10,000	$100,000,000	$200,000,000	$300,000,000	$400,000,000	$500,000,000
$20,000	$200,000,000	$400,000,000	$600,000,000	$800,000,000	$1,000,000,000
$35,000	$350,000,000	$700,000,000	$1,050,000,000	$1,400,000,000	$1,750,000,000

For 50,000 wells the total cost could vary from $125 million to $1.75 billion based on per well equipment needs. It may be that key compressor locations and gas processing facilities, if winterized or supplied with additional liquid storage tanks, could mitigate a significant percentage of the cold weather flow problem. The total number of these locations is likely to be much reduced from the number of wells noted in Table 5 above. If 1000 facilities of this type required a $10,000 investment each the total would equal $10 million, a much reduced number from those illustrated above.

Table 6 which follows itemizes capital cost and operating expenses for winterization of production facilities. The capital costs do not total within the spreadsheet as there is duplication of equipment in some cases.

Table 6 – Itemization of Capital and Operating Expenses for a Typical Gas Well – (Note, the Capital Costs Items Listed in the Table are not Totaled as Locations will require a Subset of these Items).

Gas Well Winterization Expenses						
Cold Weather Protection Equipment		**Description**		**Cost Per Well - Excludes Duplicate Applications**	**Source**	
Capital Cost						
Winterized Production Unit - Net Cost for Winterization		Production unit winterized by internal piping and insulation.		$23,000	Sivals Engineering, Odessa, Tx., Ref 20	
Methanol Injection Pump		High Pressure Pump to Inject Methanol		$1,648	ZKO Oilfield Industries, Ref. 11	
Timberline solar powered methanol pump w/solar panels				$2,800	Timberline Manufacturing, Ref. 22	
Chemical Pump to Supply Chemical Inhibitors		Chemical Inhibitor Pump for Corrosion Protection		$1,350	ZKO Oilfield Industries Ref. 11	
Vent Gas Bottle to Supply Heater		System to Collect Vent Gas from Injection Pumps to Supply Heaters		$675	ZKO Oilfield Industries Ref. 11	
Methanol Tank		Stores Methanol		$1,000	estimate	
Methanol Injection Tubing - High Pressure - $5/Ft - 100 Ft		Methanol Transfer		$500	Drillspot .com	
Flow Line Insulation - $3/Ft - 100 Ft		Insulate Flow Line		$300	Drillspot .com	
Flow Line Heat Tape - $4/Ft - 100 Ft		Provide Heat to Flow Line		$400	Drillspot .com	
Fiberglass Hut for Enlcosing Production Equipment		Weather Protection		$500	JW Williams Co. Casper, Wyoming, Ref. 21	
Catalytic Heater for Location Housing		Heating for Hut		$500	ZKO Oilfield Industries Ref. 11	
Installation Cost - 2 men for 3 days at $50 per hour.		Labor		$2,400	JW Williams Co. Casper, Wyoming, Ref. 21	
Operating Expense for Methanol Injection						
Methanol costs are $4.00 per gallon. Assume 10 gallons per day for 5 months. Methanol cost = 5 months * 30 days/mo.*10 gal/day * $4/gallon = $6000		Methanol Cost		$6,000	Timberline Manufacturing, Ref. 22	
Maintenance - Per Month - $200 @ 5 months				$1,000		
Total - Cost per Year				$7,000		

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From: Charise Wilson
To: Charise Wilson
Subject: NERC Reliability Assurance Initiative – Concept White Papers Posted
Date: Monday, November 26, 2012 6:31:30 PM

Reliability Assurance Initiative – Concept White Papers Posted

November 26, 2012

Ladies and Gentlemen:

The Reliability Assurance Initiative is for identifying (and implementing where appropriate) changes that enhance the effectiveness of the Electric Reliability Organization (ERO) compliance and enforcement program to avoid cascading events and the resulting major loss of load. This undertaking is for the purpose of the ERO outlining to the Federal Energy Regulatory Commission (FERC) revised practices that better achieve a risk based compliance monitoring policy objective and identify the end state of a mature compliance monitoring program to be fully functional and implemented by 2016. Activities include drafting six conceptual white papers that describe the desired end state and change state elements necessary to achieve the attributes of compliance of a mature ERO. The white papers and the corresponding input and feedback to these papers will be included in a formal filing to FERC targeted for March 2013.

The overarching conceptual white paper and the first Key Change State Element paper, "Restyle the Compliance Monitoring Approach," have been posted to the NERC website under Reliability Assurance Initiative. Additionally, questions specific to the first paper have been posted for industry comment and feedback; this includes feedback on the desired value outcome of reliability assurance from the end-state program. It is recommend that all Regional Entities and registered entities check the NERC website regularly to ensure the latest version of each paper is being used, as each paper will be updated on a routine basis based on feedback submitted to NERC.

Anticipated posting dates for the remaining papers are provided below:

Paper No. 1 – Overarching Conceptual White Paper (Posted)

Change State Element Paper No. 2 – Restyle the Compliance Monitoring Approach (Posted)

Change State Element Paper No. 3 – Establish Compliance Data Requirements – Target Posting Date: December 10, 2012

Change State Element Paper No. 4 – Refine Compliance and Enforcement Information Flow – Target Posting Date: January 7, 2013

Change State Element Paper No. 5 – Redesign the Enforcement Strategy – Target Posting Date: January 21, 2013

Change State Element Paper No. 6 – Pilot Program – Target Posting Date: February 4, 2013

Entity comments and responses to posted questions should be submitted to: RAIcomments@nerc.net
For more information or assistance, please contact Jerry Hedrick (Via Email) or at (404) 446-9704; Earl Shockley (Via Email) or at (404-446-2560)

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Reliability Assurance Initiative

Purpose of the Reliability Assurance Initiative (RAI)

The RAI is to identify and implement changes that enhance the effectiveness of the Electric Reliability Organization (ERO) compliance and enforcement program to avoid cascading events and the resulting major loss of load. The foundational principles of the RAI are that:

- It is not practical, effective or sustainable for the ERO Enterprise and Registered Entities to monitor and control all compliance to the same degree.

- It is not practical, effective, or sustainable for the ERO Enterprise and Registered Entities to treat all findings and discrepancies, as violations triggering the same degree of enforcement and evidentiary documentation.

The RAI will be successful if the end state compliance monitoring and enforcement program is effective (resources expended to achieve and monitor compliance and carry out enforcement are sufficient on the larger risk areas and not unnecessarily over applied on lower risk areas) at providing reasonable assurance through compliance monitoring, appropriate deterrence through enforcement and a feedback loop to continuously improve reliability standards.

Activities of this initiative will include drafting of conceptual white papers describing the desired end state attributes as well as the change state elements necessary to achieve the attributes of compliance for a mature ERO. The white papers and the corresponding input and feedback to these papers will be included in a formal filing to FERC targeted for March 2013.

Background

Over the last five years through experience with the compliance and enforcement processes and feedback from stakeholders, the ERO Enterprise has envisioned an end state for compliance and enforcement that is founded on a risk-based approach. This vision will be developed through maturing the ERO Enterprise processes over the next three to five years and be tested through a pilot project as we reach full implementation.

The risk-based approach the ERO Enterprise envisions will consider risk relative to the tools and *processes* applied to assure compliance as well as the disposition of instances of noncompliance

incorporate risk concepts. To this end, the future risk-based approach of the Compliance Monitoring and Enforcement Program (CMEP) will be a consistent (ERO Enterprise-wide) application of (A) compliance monitoring practices based on risk, (B) a "range of tools" to prioritize and treat violations based on risk, (C) enforcement practices with clear distinctions based on risk to reliability and (D) a strengthened feedback loop from compliance monitoring and enforcement to the standards development process to incorporate considerations of actual risk into the standards development process. This overall risk-informed end state will guide registered entities to be increasingly focused on reliability and toward self-critical corrective actions which will result in continuous contribution toward reliability. At the same time, the current enforcement and penalty model will be used for higher risk or serious violations.

Conceptual White Papers

This paper is the second in a series of six conceptual white papers that outline the foundational principles and the major change state elements for the RAI. The first white paper presented overarching fundamentals and the end state vision of the RAI. The remaining five papers will better outline the major change state elements and a pilot program to tests the concepts. NERC is seeking industry feedback on the fundamental design of the concepts and the proposed policy changes. This input will be solicited in the form of structured questions which will accompany each white paper. Each of these papers and their corresponding questions will be announced and posted on the NERC website. Below is a diagram that outlines the target posting dates.

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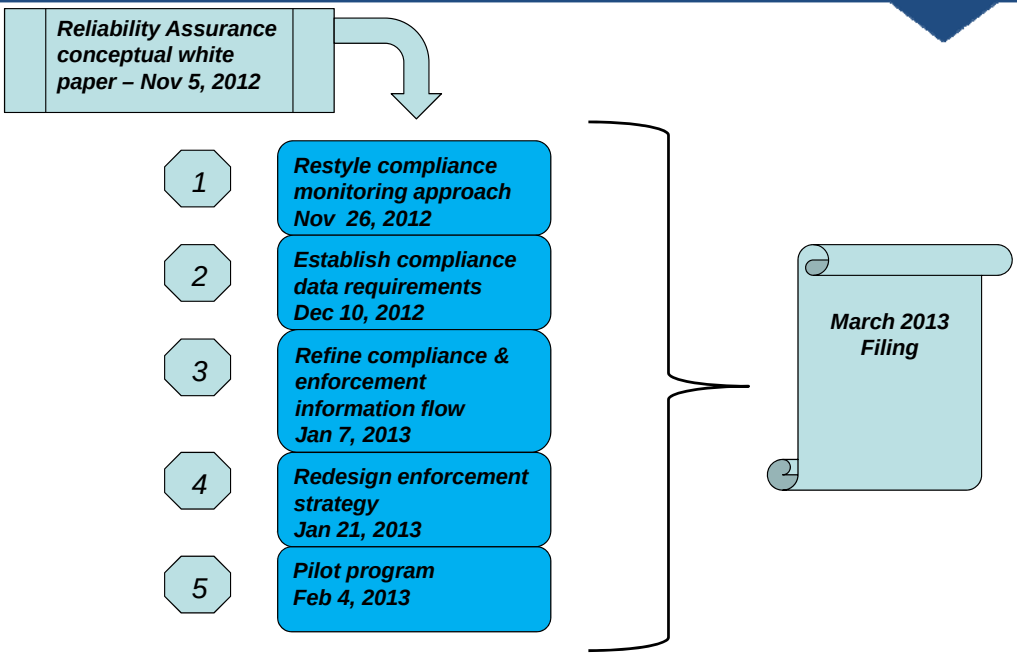
White Paper Strategy



Change State Element No. 1 – Restyle the Compliance Monitoring Approach

I. PURPOSE:

The purpose of this paper is to begin the discussion of key elements and activities that are necessary for a mature compliance monitoring program to be fully functional and implemented by **2016**. The compliance monitoring program will evolve in a deliberate and purposeful manner over the next four years and will identify near-term solutions and long-range activities that lead to its full implementation. Details pertaining to development, implementation, the timing of implementation, and measurements of success will be provided in successive releases of this paper and subsequent to a filing with the Federal Energy Regulatory Commission (FERC or Commission). The basis of these concepts will be outlined in this paper, vetted with stakeholders, and presented in the planned March 2013 filing with FERC. This filing will outline the initiatives that support a desired end state for a sustainable and consistent Compliance Monitoring and Enforcement Program.

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The end state of the compliance monitoring program consists of:

- Self-monitoring registered entities that work with the Compliance Enforcement Authority (CEA) to make determinations of risk and levels of reporting.
- Professional development of staff to promote consistency of approach and uniformity of processes through the use of standardized tools.
- Annual compliance monitoring planning[1] that properly balances risk and coverage relative to the use of compliance monitoring methods (*See*, § IV.3 below).
- Audit design that considers risk in the scoping of engagements, relies on tests of controls to gain reasonable assurance of compliance, considers data requests that supports the testing of controls, and determines staffing appropriate to the engagement.
- A robust program that utilizes sound professional judgment and provides Enforcement with determinations.
- CEA reporting that provides strong recommendations that support corrective actions, an opinion that there is a reasonable assurance of sustainable compliance, and findings that are relevant and meaningful.
- A quality assurance program that utilizes established Key Performance Indicators (KPI) to measure results, identify process improvements, and communicate results for the ERO Enterprise.

[1] North American Electric Reliability Corporation, Rules of Procedure: Section 400, Compliance Enforcement; See also, Rules of Procedure: Appendix 4C: Compliance Monitoring and Enforcement Program.

II. COMPLIANCE MONITORING:

Ensuring the reliability of the bulk power system (BPS) is a primary objective of industry and is the mission of the North American Electric Reliability Corporation (NERC) and the Regional Entities (collectively, the ERO Enterprise) and FERC. The NERC Reliability Standards define the mandatory requirements applicable to users, owners, and operators of the BPS for ensuring its reliable planning, operation and protection. Compliance monitoring serves the foundational purpose of promoting confidence and elevating the level of assurance that registered entities are complying with reliability standards. Further, compliance monitoring serves the public interest by providing necessary accountability and transparency in regard to compliance with mandatory standards. Finally, compliance monitoring provides value and process improvement information, which allows a registered entity to strengthen its operations. The changes introduced in this paper are intended to reinforce the trust of the public, industry, and government with the primary understanding that NERC's objective is compliance in the service of reliability. In this regard, the compliance monitoring approach will be restyled to be more explicitly shaped around the risk to reliability. The primary focus of the ERO Enterprise going forward will be on implementing an "Integrated Compliance Framework" that focuses on people, processes and systems. This approach to compliance monitoring will be introduced and embedded across NERC's business groups. This will drive uniformity and provide the public with a reasonable assurance of compliance.

The Integrated Compliance Framework (Framework) will provide a coherent system that facilitates consistent development, interpretation, and application of concepts, methodologies, and techniques across the ERO Enterprise. This Framework supports a more robust compliance monitoring process that: (1) considers risk in the compliance monitoring methods; (2) evaluates a registered entity's controls for ensuring compliance with Reliability Standards and actions taken in the event of noncompliance; (3) utilizes tests of those controls to provide greater assurance for sustained compliance that mitigates reliability and security risk; (4) provides uniform practices; (5) empowers increased use of regional discretion; and (6) supports robust systems to promote higher transparency and greater efficiency. The Framework includes defining capability development needs (focusing on people and systems) and honing compliance monitoring practices (focusing on audit processes). The Framework will define key focus areas for the full program implementation. The Pilot Program (to be introduced in a later concept paper) will demonstrate the application of the Framework and allow for refinement prior to full program implementation (e.g., development of systems, training, and procedures to replicate across the Regional Entities and NERC). The outline for each focus area is provided below, and activities supporting each initiative are located in the Appendix.

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Integrated Compliance Framework

Capabilities Development: (*See*, § III below)

- ✓ People
    1. Acquire – Create common staffing practices.
    2. Develop – Design core training, education and evaluation programs to drive consistency.
    3. Retain – Identify development and performance growth opportunities.
- ✓ Systems
    1. Tools – Establishing uniform tools and applications across the ERO Enterprise.
    2. Reporting – Standardized documentation to promote consistent communication.
    3. Evaluation – Continuous improvement with transparent communication.

Compliance Monitoring Practices: (*See*, § IV below)

- ✓ Processes
    1. Audit Techniques – Compliance that uses professional standards and practices.
    2. Audit Planning Tools – Regional flexibility to plan and execute engagements based on risk and required coverage.
    3. Compliance Monitoring Methods – Using existing monitoring tools to gain reasonable assurance of compliance.
- ✓ Centers of Competency (COCs)
    1. Multi-Regional Registered Entities – Cross-regional teams performing singular entity engagements.
    2. Complex Standards – Leveraging core regional skills for complex audits.

Pilot Program Design: (*See*, § V below)

The pilot program will be built using a phased approach. It will initially focus on select Regions and registered entities and will evolve as people, processes, and systems advance and are able to broadly apply the changes. Elements that will be addressed in the future Pilot Program paper include:

- ✓ Entity Selection – Establish criteria for participation and expectations for participation
- ✓ ERO Enterprise Alignment – Formalizing approach across and among the Regions
- ✓ Process Development – Create and conduct training to establish consistency
- ✓ Pilot Program Evaluation Criteria – Create baseline measurements and communication processes to demonstrate processes, modify approaches, and implement improvements to the overall implementation design.

Restyling the compliance monitoring approach is grounded in foundational audit principles (e.g., Generally Accepted Government Auditing Standards (GAGAS) and the International Professional Practices Framework by The Institute of Internal Auditors (IIA)) and NERC's governing documents (e.g., Rules of Procedure (ROP) and Compliance Monitoring and Enforcement Program (CMEP)). The Framework will provide a structural design that incorporates the current body of knowledge and

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guidance to drive a coherent and consistent approach to compliance. Focusing on people, processes, and systems will ensure the ERO Enterprise is grounded in the foundational purpose of compliance monitoring as well as the long-range sustainability of the compliance monitoring program. Through the use of a pilot program, processes will be demonstrated, while designs of systems and training of people will be refined for full implementation. The Pilot Program will be described in a subsequent concept paper.

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III. CAPABILITIES DEVELOPMENT:

Capabilities development addresses necessary resource attributes for managing an effective ERO Enterprise that operates in a consistent and sustainable manner. The adoption of common practices for staffing and systems will facilitate the ERO Enterprise in achieving desired end-state elements. The two primary resources with the greatest impact on an organization carrying out its responsibilities are people and the systems they use.

A. People

Staffing, specifically the acquisition, development, and retention of staff, is paramount to achieving the desired end state.

1. *Acquire* – Creating common staffing practices is fundamental to all ERO Enterprise compliance monitoring functions. The following activities will be performed to achieve alignment:
   - Create a standard staffing prototype that identifies critical capabilities required to meet staffing objectives and sets appropriate standards and criteria.
   - Review all auditor job descriptions across the ERO Enterprise to define best practices and approach to staffing.
   - Create routine processes to evaluate appropriate staffing needs to achieve a proper balance of engagements based on risk and coverage.
   - Create a monitoring and reporting process to routinely review and discuss talent acquisition, staffing levels, and auditor development.
2. *Develop* –"Auditors must use professional judgment in planning and performing audits and in reporting the results."[2] Designing core training and educational and evaluation programs ensures the consistency of a compliance monitoring approach. In order to carry out their professional duties, the compliance auditors must possess requisite knowledge, skills, and applicable competencies. The following activities will be performed to achieve alignment:
   - Ensure applicable GAGAS and IIA rules of conduct and ethical principles are followed and are part of the ERO Enterprise's core policies and procedures.
   - Identify necessary competencies to create a robust training program.
   - Develop a mandatory ERO Enterprise-wide training and continuing professional development program.
   - Create a uniform auditor evaluation and feedback form with defined competencies.
   - Define training and evaluation frequency.
   - Conduct annual capability assessments and report the results as well as any corrective measures.
3. *Retain* – Sustaining a high organizational competency level requires retaining competent and highly skilled talent while providing development and performance growth opportunities. The following activities will be performed to achieve alignment:
   - Identify competencies to create a continuous training program.

[2] Government Auditing Standards, Chapter 3, Section 3.60 - Professional Judgment

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- Create a set of common ERO Enterprise core competencies and performance criteria.
- Design development and performance feedback tools.

B. Systems

The use of uniform tools, systems, and applications will provide for consistent and harmonized processes and procedures across the ERO Enterprise, securely managed information, consistent reporting, and the ability to evaluate program effectiveness. Additional benefits include: saving time and ensuring consistency by creating common templates that provide flexibility as needed; improving auditor efficiency by enabling them to test, document and report in a repeatable and sustainable manner; and improving collaboration by enabling information sharing across the ERO Enterprise.

1. *Tools* – An effective ERO Enterprise utilizes common tools and information system applications to ensure data is retained in a secure and consistent manner and that tools are designed to facilitate a common approach. The following activities will be performed to achieve alignment:
   - Identify and catalogue all existing ERO Enterprise tools and applications.
   - Evaluate each tool and application for use, purpose, and design.
   - Adopt best practice tools and applications across the ERO Enterprise.
   - Identify an existing system or recommend implementation of a centralized compliance monitoring management solution to be utilized across the ERO Enterprise.
   - Eliminate applications and tools that prevent common practices (except for identified Region-specific needs).
2. *Reporting* – Accurate and precise communication is necessary to convey strong recommendations that support corrective actions; present findings in a relevant and meaningful manner; and provide reasonable assurance of sustainable compliance with standards. The following activities will be performed to achieve alignment:
   - Design a standardized report format.
   - Develop consistent writing practices.
   - Create or adopt a uniform style guide and provide continuous training.
   - Define metrics to measure consistency of reporting.
3. *Evaluation* – Continuous improvement is facilitated by developing and reporting on KPIs. Success is a measurement of progress towards goals, the demonstration of repeated achievement, and an established level of performance. Understanding what is important and reporting the level of achievement is necessary for any organization to continuously improve. The following activities will be performed to achieve alignment:
   - Define consistent and meaningful measurements pertaining to the execution of compliance monitoring activities.
   - Establish measurements for execution to the change state elements.
   - Create reporting mechanisms to demonstrate achievement of KPI goals.
   - Track and monitor the completion of management actions.

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IV. COMPLIANCE MONITORING PRACTICES:

Compliance monitoring is performed by the ERO Enterprise in diverse environments within registered entities that vary in size and structure. While risk and the designs of controls may vary, the application of audit techniques and tools should not. Compliance monitoring practices address the consistent application of audit techniques and the use of uniform tools to carry out compliance monitoring activities. The use of common tools and practices is fundamental to the credibility and reliability of an auditor's report. Compliance monitoring practices must continue to adhere to guidance provided by the ROP and be grounded in specific requirements set out through GAGAS and IIA for conducting engagements. In this regard, these documents serve as our foundational principles for executing compliance activities, and our objective is to demonstrate their use in a more transparent manner.

A. Processes

Processes allow us to define a methodology or set of tools that, when applied in a similar fashion, should result in a consistent output. Defining and applying well-defined techniques, tools, and methods to perform compliance monitoring will drive the ERO Enterprise to audit, review, and assess information in a consistent manner that leads to similar results and conclusions.

1. *Audit Techniques* – Auditing, by design, should provide objective analysis and information needed to make decisions necessary to determine compliance. Utilizing foundational approaches presented by the IIA and GAGAS provide for the design and staffing of an engagement as well as fundamental activities related to audit planning, performance (production), communication (publish), and the monitoring of mitigation plans. Following this guidance will assure that audits are properly staffed, designed, and executed in a coordinated and consistent manner. The following activities will be performed to achieve alignment:
    - Evaluate existing planning activities and related processes to create a uniform design specifically focusing on:
        - Understanding the risks associated with the registered entity
        - Defining engagement objectives
        - Determining data request needs
        - Determining resource allocation and needs relative to scope
        - Understanding registered entity control design
        - Determining tests of controls to establish reasonable assurance of compliance with reliability standards
        - Documenting planning activities to support work and ensure that any on-site testing is properly designed, effective, and efficient
    - Evaluate existing production activities and related processes to create a uniform design
        - Develop consistent testing methodology
        - Set criteria for information requirements to achieve engagement objectives
        - Implement criteria for maintaining documentation of work
        - Assess existing templates to determine if they should be adopted, changed, or removed and what additional templates are required

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- Evaluate existing publication activities and related processes to create a uniform design (*this is addressed in the Systems section, III.B.2 "Reporting")
- Mitigation Plans – review processes and systems for documenting, tracking and validating the implementation of corrective actions

2. *Audit Planning Tools* – It is the responsibility of NERC to work with the Regional Entities to develop and provide useful tools. In certain instances these tools should also be beneficial to industry to evaluate risk, test their controls, understand the achieved compliance through those controls, and develop necessary corrective actions, as well as facilitate dialogue with the appropriate CEA. The following activities will be performed to achieve alignment:
   - Evaluate and adapt existing tools:
     - Actively Monitored List (AML) – modify the design to provide information relevant to the ERO Enterprise to empower the Region to determine a registered entity's audit scope based on risk and the understanding of controls
     - Annual Monitoring Plan – create a uniform ERO Enterprise Implementation Plan that is based on ROP coverage requirements and consideration of risk. Monitoring plans should:
       - Properly plan for required coverage
       - Balance resources for risk
       - Build in white space to add registered entities or flex for emerging risks
       - Be flexible to change engagements
       - Address risk relative to the entity
       - Understand staffing requirements relative to audits, spot checks, review of self-certification documentation and data submittals
     - FERC "13 – Questions" on Internal Compliance – Review the questions for incorporation into the risk assessment process.
     - Reliability Standard Audit Worksheet (RSAW) – Evaluate the document and potentially redesign it to assure it is a valuable tool that can be applied by auditors in the execution of their compliance monitoring work and by industry to have transparency to those approaches. Further, the processes must be reviewed for the maintenance and warehousing of the documents.
   - Continue to develop tools and identify opportunities for additional ones:
     - Entity Impact Evaluation (EIE) – The existing template needs to be reviewed to better define the attributes of risk that are necessary to monitor a registered entity for compliance with Reliability Standards, determine appropriate monitoring methods and scope (e.g., Audits, Spot Checking, etc.), and define the capture, retention, and maintenance of data.
     - Through the course of cataloguing tools relative to the documentation of systems, determine if additional tools exist that can be developed and applied to aid in audit planning.
3. *Compliance Monitoring Methods* – The ROP provides four primary compliance monitoring discovery methods to be used to assess compliance with Reliability Standards. In addition to

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these methods, self-reporting is a very important aspect of the program as it is the most efficient way to identify issues annually accounts for nearly two-thirds of reported violations. In this regard, the ERO Enterprise wants to look for the discovery methods to be complementary to this reporting mechanism. Annual plans should allocate resources to activities to address risk and comply with refined coverage requirements while providing flexibility to address emerging risks.

- *Audits* – Audits involve a significant amount of resources and time and should be reserved for high-risk and complex engagements. Audits should be scoped to address the potential risk the entity poses to the BPS and the potential risk to comply with established reliability standards. Audits may be performed off-site or on-site; scoping may be broad or narrow; testing depth will vary depending on the design of controls and the level of assurance that can be obtained to determine that controls are functioning as designed. In this regard, audits must be redesigned from the current rigid structure to a more flexible format that allows Regional Entities to select the standards for the audit scope. (During 2013 we will undertake a project to review the AML to design a tool that better aids ERO Enterprise audit planning). The design of the audit engagement will be based on multiple opinions and scoped according to risk and the need to comply with coverage requirements outlined in the ROP. Audits will not be "one size fits all."
- *Spot Checking* – Spot Checking is an effective method to validate self-certification, periodic data submittals, mitigation activities, Find, Fix and Track, and Technical Feasibility Exceptions. It is an effective method for monitoring corrective actions as a result of items noted through an engagement or responding to emerging or changing risk. The method provides a level of precision that allows a Region to quickly mobilize to address changing or newly identified risk. Annual Implementation Plans should be designed to allow resources to be deployed based on risk assessments and changing needs.
- *Periodic Data Submittals* – Data submittals provide a cost-effective method for verifying compliance with reliability standards. Data submittals should be used to verify information submitted through self-certifications, as a tool to follow up on corrective actions, and as a way to quickly assess a registered entity's capability of handling emerging risks. Periodic data submittals should be designed into the overall annual plan and also used as a method when on-site visits cannot be performed. Ensuring that these submittals are efficient and useful—and not simply intensive paper exercises—is important to their effectiveness.
- *Self-Certification* – The self-certification tool should be designed to effectively engage with registered entities out of audit cycle in order to monitor changes in systems and control design and to discuss self-identified findings to ensure continued compliance. Self-certifications should also be used as a method to maintain a perpetual entity risk profile that would aid in scoping future engagements or trigger potential spot checking. Self-certifications need to be reviewed and assessed by the Regional Entities to identify what is being reported and determine any needed actions. Activities necessary to evolve this method include:
    - Assessing the current data request template for modifications

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- Defining data and informational needs to minimize intrusiveness
- Designing a process to tailor self-certifications based on entity risk
- Building processes into annual planning to ensure certifications are reviewed and tested
- Creating a feedback process with the entity to provide possible process improvements or recommendations

B. Centers of Competency

The purpose of the Center of Competency will be to address a Multi-Registered Regional Entity's (MRRE) unique organizational structure. A center of competency will leverage a deep entity or functional expertise (at the Regional Entity level) to deliver an effective and efficient review that is applied in a consistent manner. Centers of competency will be built around three defining features:

- Demonstrated expertise
- Structured processes
- Continuous improvement to ensure approaches become more efficient

Skill sets will be used collaboratively across the ERO Enterprise to provide accountability within the regional footprint while activities are orchestrated out of the Center of Competency. An effective Center of Competency will optimize scarce resources, reduce engagements times, decrease duplication, and build on past successes.

V. PILOT PROGRAM:

The proposed Pilot Program will be outlined in the fifth concept paper, which collectively with the first four papers will form the basis of the informational filing with FERC in March 2013. General concepts and the purpose of the Pilot Program are being introduced within this paper to solicit discussion. The program will be managed in phases with the first phase beginning during the first half of 2013 and the final phase, which will lead to full implementation, occurring in the second half of 2015. Throughout each phase of the program, we will continue to refine audit tools and processes, deliver relevant training to develop staff capabilities, and openly communicate results while broadening capabilities and applications by Region and entity.

VI. CONCLUSION:

Restyling the compliance monitoring approach is built around reaching a desired end state that:

- Focuses on reliability to the Bulk Electric System
- Encourages self-monitoring of registered entities
- Fully utilizes discovery methods
- Balances risk and coverage to develop annual plans and design engagement;
- Utilizes tests of controls to validate compliance
- Delivers reports and findings that are relevant

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- Supports the use of uniform tools by highly trained professionals
- Effectively provides information to Enforcement
- Openly communicates results

The ERO Enterprise approach is grounded in foundational audit principles and the ERO Enterprise governing documents. Focusing on people, processes, and systems will drive consistency and uniformity of approach. Through the use of the Pilot Program, we will demonstrate tools and approaches while designs of systems and training of people will be refined to reach full implementation. This paper serves as a basis for developing direction, setting high-level projects and sub-projects, assigning ownership, and establishing delivery dates. Provided as an appendix to this paper are three tables that discuss the activities to be undertaken. These tables will evolve as the ERO Enterprise identifies specific activities that must occur to support the sustainable end state.

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APPENDIX

Table 1 - People

Primary Activity	Action	Regional Lead	Delivery Date
Acquire	Identify team to begin assessment	MRO	2/1/13
	Review existing job descriptions		5/1/13
	Identify and define core auditor competencies		7/1/13
	Develop standard staffing prototype		8/1/13
	Perform a regional staffing capability review and report results		10/1/13
	Create defined interviewing processes and interview training		10/1/13
	Create a long-term talent acquisition strategy and metrics		11/1/13
	Recommend proper staffing levels for risk and coverage		12/1/13
	Train staff how to interview candidates		
	Begin executing on acquisition strategy		
	Develop standardized annual reporting tool for staffing		12/1/13
Develop	Identify team to begin assessment	SERC	2/1/13
	Review all existing training tools and resources		5/1/13
	Provide recommendations on existing tools and needs		7/1/13
	Create development plan for staff, lead and managing auditors		
	Create tools to track training		
	Set minimum standards for training		
	Develop uniform auditor performance feedback tools		10/1/13
	Create training plan for existing staff		
	Create plan for newly acquired talent		
	Create annual review process for performance and development		12/1/13
	Reach full ERO Enterprise staff development		12/1/15
Retain	Identify team to begin assessment		2/1/13
	Review all existing retention tools – job growth, salary, etc.		5/1/13
	Report back recommendations		7/1/13
	Define key metrics for success of retention		
	Create annual reporting to discuss metrics		12/1/13

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Table 2 - Processes

Primary Activity	Action	Project Lead	Delivery Date
Techniques	Planning Activities:		
	Identify team to perform assessment		
	Review and perform analysis on all planning activities		
	Make recommendations for best practices and needs		
	Create a uniform planning process		
	Deploy the uniform planning process		
	Production Activities:		
	Identify team to perform assessment		
	Review and perform analysis on all production practices		
	Provide recommendations for best practices and needs		
	Establish processes for assessment and testing of controls		
Audit Planning Tools	Identify team to begin assessment of tools	WECC	2/1/13
	Review and assess all audit planning tools and resources		
	Provide recommendations on base practices and needs		
	Review Actively Monitored List and make change recommendations	NERC	5/1/13
	Review CMEP-IP and make change recommendations	NERC	5/1/13
	Review RSAWs and make change recommendations	NERC	9/1/13
	Restart the EIE project and further define deliverables		
	Develop annual plans that leverage monitoring tools		
	Evaluate the current design of tools for application		
Compliance Monitoring Tools	Identify team to begin assessment	RFC	
	Audit:		
	Define the planning, production and publication phases		
	Create common work-paper procedures		
	Assess processes for on/off site engagements and scoping		
	Spot Checks:		
	Assess existing procedures for spot checks		
	Provide recommendations for restyling spot check		
	Implement spot check process changes		
	Data Submittals:		
	Establish team to define parameters and uses of submittals	SERC	
	Self Certification:		
	Determine system needs to capture and track submitted data		
	Evaluate tool relative to self reporting and information needs		
Center of Competency	Identify team to assess uses of a COC to address MRREs		2/1/14
	Provide recommendations to design audits for MRREs		7/1/14
	Identify lead regions by MRRE		12/1/14
	Develop audit engagement plan for MRREs		2/1/15

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Table 3 – Systems

Primary Activity	Action	Project Lead	Delivery Date
Tools	Leverage the existing D&T/ITSG report to further develop actions		
	Identify team to begin assessment		4/1/13
	Catalogue and identify all systems, applications and tools		7/1/13
	Evaluate all systems, applications, and tools		
	Identify system and application needs and recommend new or develop		
	If new systems and applications are required develop RFP		
	Issue RFP / RFQ		
	Provide recommendations		
	Set implementation schedule		
	Sunset all systems, tools and applications based on recommendations		
Reporting	Identify team to begin assessment		
	Review all reporting formats and assess writing skill needs		
	Create a uniform reporting format		
	Deploy the uniform reporting format		
	Create uniform style guide		
	Identify COC by entity		
Evaluation	Identify team to begin assessment		
	Inventory and catalogue all ERO Enterprise applications and tools		

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Glossary of Terms:

1. Compliance Enforcement Authority (CEA) – The entity responsible for assessing performance or outcomes if an entity is compliant with the associated Reliability Standard. The Compliance Authority may be either NERC or the Regional Entity.

2. ERO Enterprise – Refers to NERC and the eight Regions collectively.

3. Multi Regional Registered Entities – Entities that operate across more than one defined regional territory.

4. Center of Competency – A Center of Competency will be level of demonstrated competency at the Regional Entity level.

5. Complex Standards – Circumstances or situations that require a specific skill set or experience that may not be a core competency within a given Region.

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Change State Element #1, Concept Paper
Restyle the Compliance Monitoring Approach

Feedback Questions for stakeholders:

1. From a registered entity perspective, how is the current compliance monitoring methods driving industry behavior. What should change?
2. What are the greatest burdens of time and resources for preparing for an audit and what can be done to alleviate the burden while still achieving reasonable assurance of compliance?
3. As a registered entity, what level of compliance monitoring and information gathering do you believe would provide NERC and Regional Entities assurance that you are meeting compliance obligations?
4. How does your entity sustain reasonable assurance of compliance with standards between scheduled engagements?
5. How should risk be considered in planning an audit? What elements of risk do you believe are relevant?
6. What are the anticipated challenges of considering risk for scoping and utilizing controls to gage compliance?
7. What are the anticipated benefits of monitoring activities considering risk for scoping and utilizing controls to gauge compliance? What are your concerns?
8. From a registered entity perspective, what types of reliability activities should be monitored with risk controls? Are these elements controllable? What reliability activities would not lend themselves to being monitored with risk controls?
9. As a registered entity, how do you feel professional judgment is being exercised today? What changes or improvements would you like to see?
10. Multi Regional Registered Entities - What are the most important considerations the ERO should focus on that will drive consistency or uniformity of the compliance program?

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Incorporating Risk Concepts into the Implementation of Compliance and Enforcement

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Incorporating Risk Concepts into the Implementation of Compliance and Enforcement

I. Introduction and The Need for Change

The Energy Policy Act of 2005 (the Act) created a reliability framework that includes the Federal Energy Regulatory Commission (FERC or the Commission), the Electric Reliability Organization (ERO) (designated as the North American Reliability Corporation (NERC)), and eight Regional Entities (NERC and the Regional Entities, collectively referred to as the ERO Enterprise) with thousands of stakeholders and nearly 2000 entities subject to the ERO's rules. Three of the primary responsibilities outlined by the Act are developing standards, promoting and monitoring compliance with those standards and enforcing acts of non-compliance with the standards – all with the overarching objective of avoiding cascading events and the resulting major loss of load.

Compliance and enforcement of the standards was delegated to the eight Regional Entities, subject to oversight by NERC and FERC. This responsibility came with the requirement and expectation that every violation, regardless of risk, be prosecuted. Violations came with the prospect of significant monetary penalties for noncompliance. This "zero tolerance" application of compliance and monitoring without regard to the risk to the bulk electric system (BES) has unduly focused attention and resources on compliance risk and administrative processes as opposed to reliability risk.

Over the last five years' through experience with the compliance and enforcement processes and feedback from stakeholders, the ERO Enterprise[1] has envisioned an end state that is founded on a risk-based approach. This vision will be developed through maturing the ERO Enterprise processes over the next three to five years and be tested through a pilot project as we reach full implementation[2]. It is not practical, effective or sustainable for the ERO Enterprise and Registered Entities to monitor and control all compliance to the same degree. Further, it is not practical, effective, nor sustainable for the ERO Enterprise and Registered Entities to treat all findings and discrepancies, as violations triggering the same degree of enforcement and evidentiary documentation. Where a violation does not pose a serious or higher risk to the reliability of the bulk power system, and the Registered Entity has a compliance program and internal controls that detect, assess, mitigates and self-reports the violation, the Regional Entity may decline to pursue and enforcement action.

[1] ERO Enterprise refers to NERC and the eight Regional Entities.
[2] The end-state envisioned will be developed over time, in part through pilot projects and the measured implementation of activities, tools and processes.

The risk-based approach the ERO Enterprise envisions will consider risk relative to the tools and processes applied to assure compliance as well as the disposition of instances of noncompliance incorporate risk concepts. To this end, the future risk-based approach of the CMEP will be a consistent (ERO Enterprise-wide) application of (A) compliance monitoring practices based on risk, (B) a "range of tools"[3] to prioritize and treat violations based on risk, (C) enforcement practices with clear distinctions based on risk to reliability and (D) a strengthened feedback loop from compliance monitoring and enforcement to the standards development process to incorporate considerations of actual risk into the standards development process.[4] This overall risk-informed end state will guide Registered Entities to be increasingly focused on reliability and toward self-critical corrective actions resulting in continuous contribution toward real reliability, rather than the current model. At the same time, the current enforcement and penalty model will be used for higher risk or serious violations.

This white paper discusses the end state envisioned as well as the benefits associated with incorporating risk management practices into the CMEP work and linking it to the standards development process through a feedback loop. Throughout the course of the whitepaper, the need and the basis for changing the compliance monitoring and enforcement work of the ERO Enterprise is established; the framework for changes to the compliance monitoring and enforcement work is presented; and the next steps to define the path forward and related activities are outlined. The changed state contemplated by this whitepaper is intended to be the basis for an informational filing by NERC with the Commission in March 2013.

II. The Proposed Changes Promote BES Reliability

The North American electric grid operating in real time is the world's most complex transmission system; in this regard, reliability risk is neither uniform across the grid nor constant over time, but is complex and interdependent. Assuring the reliability of this system requires understanding the risks that may impact its function and developing the controls to

[3] *See* Malcolm K. Sparrow, *The Regulatory Craft*, 100 (2000). Sparrow advocates using a "range of tools for procuring compliance and eliminating risks …." Our existing rules of procedure together with foundational documents referenced in the rules of procedure, such as the Yellow Book Government Audit Standards provide a range of tools which can be scoped and deployed based on risk. Those tools include audits, spot checks, data submittals and self-certifications. These tools, together with the ability of the Regional Entity to decline to enforce a violation, comprise a full "range of tools."

[4] These concepts will be implemented by (1) restyling the ERO's overall compliance approach to conform to well-established audit principles as described herein including the right to decline to pursue violations across the ERO Enterprise; (2) establishing the requirements for Regional Entity's records to facilitate NERC and FERC oversight; (3) establishing processes for information flow between compliance functions and enforcement functions as well as an open, transparent and clear approach as to which matters will be subject to enforcement procedures; and (4) redesigning the enforcement strategy to focus on serious or higher risks to the BES.

discover and mitigate those risks. Ultimately it is this proactive, risk-based approach that will allow the ERO Enterprise to provide reasonable assurance of current and future BES reliability.[5]

The end-state vision of a sound risk-based reliability approach will reflect principles that form the foundation for focus and prioritization, as well as recognition of the core elements that ensure reliability of the bulk electric system. In this end-state vision, the compliance, enforcement and standards elements form an integrated structure with focus on the priorities that most influence reliability. The alignment of processes, systems and resources will ensure the proper attention to those reliability matters. Lesser and more minor matters are considered and addressed in a far simpler fashion which encourages the documentation of internal self-corrective activities that diminish the potential for the accumulation of minor unaddressed matters.

The ERO must abandon "zero tolerance" compliance monitoring and enforcement because:

- The pursuit of all violations without regard to risk or administrative burden is neither effective nor sustainable.
- The focus has become documenting compliance, not reducing risk and improving reliability.
- Enforcement considers a historic state of reliability, not the current or future state of reliability.
- Improvements to processes, such as the administrative citation process or find, fix, track and report, reduce the ERO's administrative burden, but do not have commensurate impact on improving reliability and reducing industry's administrative burdens.

Therefore, to encourage and reward proactive self-assessment the ERO Enterprise should use a "full range of tools[6]" to shape compliance, monitoring and enforcement based on risk. The incorporation of risk management concepts into the ERO's work, from standards development to compliance monitoring and enforcement, will encourage compliance and risk mitigation.

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[5] Former FERC Commissioner and Chairman Joseph T. Kelliher stated: "The Energy Policy Act of 2005 did not outlaw blackouts and the reliability provisions of section 215 do not promise perfect reliability at any price." *See*, *Remarks of the Honorable Joseph T. Kelliher, Executive Vice President – Federal Regulatory Affairs, FPL Group, Inc., Reliability Primer for Lawyers and Energy Professionals, Energy Bar Association,* 6,7 (April 28, 2010), http://utilitysvcs.info/docs/Kelliher%20NERC%20speech.pdf

[6] A full "range of tools" includes the ability to decline to pursue a violation. *See also note 2, supra.*

III. Effective Regulation Uses Risk-Based Concepts

Moving from zero tolerance to a risk management approach requires a different way of assessing reliability concerns. Dr. Malcolm K. Sparrow advocates that regulators use a risk-based "problem solving" approach which he describes in his book, *The Regulatory Craft*[7], as the:

> systemic identification of important hazards, risks, or patterns of noncompliance; an emphasis on risk assessment and prioritization as a … basis for resource allocation decisions … capacity for designing and implementing effective, creative, tailor-made solutions for each identified problem; the use of a range of tools for procuring compliance and eliminating risks; and the recognition of the need to retain and enhance the agency's enforcement 'sting' while using enforcement actions economically and with the context of coherent compliance strategies.[8]

The ERO Enterprise will adopt a "problem solving" approach that incorporates risk-based practices into its work, similar to other regulatory bodies with compliance and enforcement responsibilities. This approach will increase BES reliability and ERO Enterprise efficiency and effectiveness. The following describes how other U.S. Federal entities use a risk-based problem solving approach.

Many US federal agencies responsible for compliance and enforcement utilize risk management practices. The Securities and Exchange Commission (SEC)[9], the Environmental Protection Agency (EPA)[10], and the Occupational Safety and Health Administration (OSHA)[11] all have

[7] *See* Sparrow, *supra* note 1.

[8] *Id.*

[9] In "Compliance Programs, Penalty Mitigation and the FERC" former FERC General Counsel and Chief of Staff John Moot cites an SEC action forgoing enforcement because "the company had quickly identified the violations, promptly reported them, remedied them internally through disciplinary actions, and taken prospective corrective action to avoid future violations." *See*, John C. Moot, *Compliance Programs, Penalty Mitigation and the FERC*, 29 Energy Law Journal 547, 562-563 (2008).

[10] The EPA's policy on Incentives for Self-Policing, Discovery, Disclosure, Correction and Prevention of Violations provides: "The revised Policy … is designed to encourage greater compliance with Federal laws and regulations that protect human health and the environment. It promotes a higher standard of self-policing by waiving gravity-based penalties for violations that are promptly disclosed and corrected, and which were discovered systematically-that is, through voluntary audits or compliance management systems." See, *Environmental Protection Agency, Incentives for Self-Policing: Discovery, Disclosure, Correction and Prevention of Violations*, 65 Fed. Reg. 19,618 (2000), http://www.epa.gov/oecaerth/resources/policies/incentives/auditing/auditpolicy51100.pdf cited by Moot, *supra* note 8 at 564-65.

[11] OSHA's "star" status program also seeks to improve safety and health outside of enforcement. Under the "star" program, OSHA can exempt employers from routine inspections and allow them to claim "star" status in exchange for maintaining exemplary safety records and satisfying other program certification requirements. The pursuit of "star" status improves employee safety and health, decreases regulatory costs and enhances an entity's reputation. S*ee* Orly Lobel, *Interlocking Regulatory and Industrial Relations: The Governance of Workplace Safety,* 57 ADMIN. L. REV. 1071, 1105-08 (2005).

policies, programs and discretion to encourage compliance and allow the agency to decline to pursue a violation based on the particular set of circumstances and facts.[12] Companies subject to regulations are encouraged to be self-policing "because government resources are limited, universal compliance cannot be achieved without active efforts by the regulated community to police themselves."[13]

FERC's processes provide "great flexibility in fashioning the most appropriate and effective remedies and sanctions for each violation…." This includes the ability to decline to pursue an enforcement matter. In its Revised Policy Statement on Enforcement[14] the Commission stated "between 2005 and 2007, Enforcement staff closed approximately 75% of its investigations without any sanctions being imposed, even though Enforcement staff found a violation in about half of those closed investigations."[15]

Risk-based concepts are clearly contemplated in NERC's Rules of Procedure Appendix 4C - Compliance Monitoring and Enforcement Program which provides: "Compliance Audit process conducted in the United States shall be based on professional auditing standards recognized in the U.S. including Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards, and standards sanctioned by the Institute of Internal Auditors."[16] These professional standards are well-established and well-accepted. They provide a principled basis for conducting the ERO's compliance monitoring work in a consistent manner and they incorporate risk-based concepts. For example, the Generally Accepted Government Auditing Standards (GAGAS) "provide a framework for conducting high quality audits with competence, integrity, objectivity and independence."[17] "GAGAS contains requirements and guidance

[12] *See*, John C. Moot, *Compliance Programs, Penalty Mitigation and the FERC*, 29 Energy Law Journal 547(2008).
[13] *See, Environmental Protection Agency, Incentives for Self-Policing: Discovery, Disclosure, Correction and Prevention of Violations, 65 Fed. Reg. 19,618 (2000),* http://www.epa.gov/oecaerth/resources/policies/incentives/auditing/auditpolicy51100.pdf *cited by Moot, supra note 8 at 564-65.*
[14] *See Revised Policy Statement on Enforcement,* 123 FERC ¶ 61,156 (2008).
[15] *Id.* at P 9. For examples of self-reports and investigations closed with no action, *see* 2011 Report on Enforcement Prepared by the Staff of the Office of Enforcement, Federal Energy Regulatory Commission (November 17, 2011), http://www.ferc.gov/legal/staff-reports/11-17-11-enforcement.pdf.
[16] *See GAO Government Audit Standards (December 1, 2011)*, 6.05, 6.16-6.22, 5.44(b.), citing *Institute of Internal Auditors (IIA) International Standards for the Professional Practice of Internal Auditing*. Chapter 6 "Field Work Standard for Performance Audits" provides an existing guide. For example, "adequacy of the audited entity's systems and processes to detect significant errors" is a factor affecting audit risk. The "nature, timing or extent" of the audit may be altered based on the auditor's assessment of internal controls. Similarly, the Institute of Internal Auditors (IIA) International Professional Practices Framework Performance standard 2130 – Control requires that the internal audit function "evaluate the adequacy and effectiveness of controls…" These themes are also common in American Institute of Certified Public Accountants (AICPA) Generally Accepted Auditing Standards (GAAS) – Standards of Field Work.
[17] *See GAO Government Audit Standards (December 1, 2011)*, 1.04.

dealing with ethics, independence, auditors' professional competence and judgment, quality control, the performance of field work and reporting."[18]

IV. The End State of the Compliance Monitoring and Enforcement Program

A. Transition to Compliance Monitoring Based on Risk

The ERO Enterprise is in the "assurance" business. There are three common risks – inherent risk[19], control risk[20], and detection risk,[21] that must be considered. The FERC approved reliability paradigm already addresses inherent risk to the BES in the functional model, tiers of standards, and degrees of violations. Accordingly, the Regional Entities' compliance staffs now seek to understand the inherent risk posed by Registered Entities to the BES by considering such factors as their registered functions and applicable standards, as well as their size, geography, technological capability, and past performance.

To move away from the existing compliance monitoring processes and incorporate a risk-based approach, the Regions will also need to understand the control risk posed by the Registered Entities, an effort that would require examining the procedures and controls[22] those entities have in place to reduce risk and comply with the standards. An agreed-upon method or set of criteria used by the ERO Enterprise that adequately addresses control risk will be developed through the course of the pilot project.[23] While the assessment methodology will be based on consistent foundational audit principles, the consideration of risk and actual design of controls will vary, as no two entities are exactly alike in system design, configuration, programs, plans, and business plans or functions performed. This approach therefore takes into account the differences in Registered Entities and the risks posed to the BES. It also reflects the well-established assurance work practice to document an understanding of controls during the conduct of work as opposed to using a generic one size fits all approach that ignores or does

[18] *Id*. at 1.05.

[19] Inherent risk is the risk posed by the Registered Entity because of intrinsic factors such as its registered functions. For example, all other factors being equal a TOP (Transmission Operator) poses more inherent risk to BES reliability than a PSE (Purchasing-Selling Entity).

[20] Control Risk refers to the risk that a violation or risk to BES reliability could occur but may not be detected and corrected or prevented by the Registered Entity's compliance program and internal control mechanism.

[21] Detection risk is the risk that the ERO Enterprise will not identify a serious or higher risk to BES reliability. Detection risk increases when inherent risk or control risk increases. Therefore, when control risk and/or inherent risk is high, audit scope and procedures must increase.

[22] *See GAO Government Audit Standards (December 1, 2011)*, 6.16-6.22, 5.44(b.), citing *Institute of Internal Auditors (IIA) International Standards for the Professional Practice of Internal Auditing*.

[23] Criteria such as the five principles of "highly reliable organizations" may be used in the beginning and refined over time – those five principles being: preoccupation with failure, reluctance to simplify, sensitivity to operations, commitment to resilience, and deference to expertise. *See generally* Kathleen Sutcliffe and Karl Weick, *Managing the Unexpected, Resilient Performance in an Age of Uncertainty*, John Wiley & Sons (2d ed. 2007).

not take into account the company's internal controls or the risk posed by the Registered Entity.

Once the ERO Enterprise establishes the method for understanding Registered Entities' risk and controls, the Regional Entities would refer to these characteristics to assess, evaluate and document the strength of those controls as part of their audits and to plan other compliance work. During the course of the pilot project the ERO will develop the practices, procedures and training to ensure consistency across the eight Regional Entities. During full deployment the ERO will continue to provide oversight and work with the eight Regional Entities to develop best practices and ensure consistency (and where applicable uniformity). Understanding both the risk and the environment within which the risk is occurring as well the Registered Entities' internal controls, the Regional Entities would take existing controls into account to develop the scope, method, and frequency of their compliance work.[24] The Regional Entities would also recognize that Registered Entities may exhibit varying levels of maturity vis-à-vis other members of the industry and/or in regard to their own distribution of resources.

These changes can be implemented by using the existing compliance monitoring tools including audits, spot checks, self-certifications, and data submittals. These tools can also be tailored both in terms of scope, conduct, and frequency based on risk and the Registered Entities' internal controls. Registered Entities that demonstrate an acceptable level of controls would be benefited by more focused testing because the risk controls could be documented and generally relied upon by the compliance staff in the conduct of the work.

The long-reaching benefits to reliability and to the industry members will be significant. Registered Entities will be encouraged to self-assess their actual controls on an ongoing basis and self-report any instances of non-compliance. These self-reports, absent significant risk to the BES, will be recorded by the Regional Entity in a segregated database without additional regulatory filings or approvals. The Regional Entity's determinations documented by work papers will be final. The Regional Entity will be accountable for and subject to oversight and audit by NERC and by FERC for the conduct of its work. The work of the Regional Entities' compliance personnel and the efforts by Registered Entities to demonstrate compliance will have a more focused scope. Thus, as a result of Registered Entities' implementing acceptable risk controls and self-reporting any instances of non-compliance, the cost of compliance will be aligned with the management of reliability risks and ultimately the cost of compliance will be

[24] Evaluating risk controls along these lines is not novel, and has been used in other industries, for example with respect to Audit Standard-5 (AS-5). *Approved by the Securities Exchange Commission, AS-5* allows auditors to scale the scope of an audit based on the strength of controls developed by the company being audited. *See PCAOB Release No. 2007-005A* (June 12, 2007). This method is also consistent with the GAO standards relating to internal controls. *See GAO Government Audit Standards* (December 1, 2011), paragraphs 6.16 - 6.22.

lower. The investments in strong procedures around reliability and security will have a far greater payoff in terms of the reliability and resiliency of the BES. Robust compliance monitoring will not only improve BES reliability but will also provide value for both the ERO Enterprise and Registered Entities.[25]

B. Transition to Prioritizing and Treating Violations in Accordance with their Risk

With an understanding of a Registered Entity's inherent and control risk, the Regional Entities' staff would then be able to consider whether and to what extent that entity's compliance with the standards poses a risk to BES reliability. The ERO Enterprise's[26] compliance monitoring and enforcement discretion will be guided by an understanding of the risk; the environment within which the risk is occurring; the Registered Entities' internal controls; any patterns of non-compliance; and the significance of the potential violation to BES reliability given the complexity, location, nature and size of the Registered Entity. Errors or potential violations that are detected through internal controls, corrected through a strong compliance culture, and self-reported generally should not be punished with administrative process, enforcement proceedings, or penalties absent a material risk to the BES.

If a Regional Entity declined to pursue a matter, it would be recorded in a database[27] that NERC and FERC could audit. This will enable the ERO Enterprise and the Registered Entities to expend their resources more efficiently and effectively, and shift focus beyond compliance risk to include meaningful self-assessments and an evaluation of risk to the BES, thereby improving the standards development process. Traditional enforcement will be reserved for matters that pose a serious or higher risk to the BES and penalties will be assessed to send clear signals to the industry about the most significant risks in order to create change.

This approach will introduce greater flexibility into the ERO Enterprise practices, which will allow it to focus on the higher risks to reliability while simultaneously providing clear signals to the Registered Entities about the ERO Enterprise's identified areas of concern and its risk prioritization. Moreover, this risk-based regulatory strategy will encourage strong internal controls and self-reporting such that self-reporting will be an objective measure of its success.

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[25] *See Ernst & Young, Leveraging Value from Internal Controls, 5 (2006)("By not aligning risk management and internal controls investments with strategic initiatives, companies are jeopardizing operational and financial performance and, over the long run, will not optimize return to shareholders.").* http://www.section404.org/UserFiles/File/research/Ernst/44_ernst_young_leveraging_value_from_internal_controls.pdf

[26] The ERO Enterprise refers to NERC and the eight Regional Entities.

[27] The database must be uniform across the eight Regional Entities and must be administratively easy for both Regional Entities and Registered Entities to use.

As the Commission has stated, "[a]chieving compliance, not assessing penalties is the central goal of our enforcement efforts."[28]

C. Transition to Utilizing Compliance Monitoring and Enforcement to Send Meaningful Signals Based on Risk

The ERO Enterprise will refine its use of the compliance monitoring and enforcement process to ensure that it provides more meaningful signals to the Registered Entities about the ERO Enterprise's identified areas of concern and its risk prioritization.

Going forward, the Regional Entity may decline to pursue possible violations that are promptly identified and reported as the result of an effective internal compliance program or controls before the occurrence of any harm. These matters will be recorded in a data base. The matter is then final as to the Registered Entity; the Regional Entity's decision and work papers are subject to audit by NERC and by FERC. This is important because it encourages the regulated community to adopt and enhance existing strong, effective controls which includes the correction of errors or instances of non-compliance that are detected. BES reliability depends on robust compliance programs and internal controls. The ERO Enterprise will retain the ability to impose penalties up to the statutory maximum and/or increased monitoring and broader audit scope, for those violations that pose a serious or higher risk and/or represent the failure to implement adequate controls.

Making a clear distinction between the ERO's response to violations that are detected, assessed and mitigated pursuant to robust internal controls and compliance programs and those matters that are discovered by the ERO or pose a serious risk to the BES will provide unambiguous signals about the ERO Enterprise's identified areas of concern and risk prioritization. More importantly, Registered Entities will strengthen their existing internal controls and compliance programs that promptly detect, assess, correct and self-report possible issues of noncompliance to the ERO Enterprise.

D. Transition to Reliability Standards Based on Risk

The ERO Enterprise will develop a feedback loop from compliance monitoring and enforcement to the standards development process that will assist in the identification and development of Reliability Standards that are intended to address the most significant risks to BES reliability. The ERO Enterprise will continue to leverage industry and ERO Enterprise subject matter experts in the standards development process and support those subject matter expert teams

[28] *See Policy Statement on Compliance,* 125 FERC ¶ 61,058 (2008) at P.1.

with legal and compliance staff expertise to help ensure that upon implementation the Reliability Standards address the intended risk to reliability and are clear, concise and narrowly drawn to avoid unintended consequences.

When a given Reliability Standard is found to be ineffective because it has only a minimal impact on reducing risk (or in fact increases risk), the ERO Enterprise will work to revise, replace or eliminate the Reliability Standard.

V. Next Steps: Implementing Risk-Based Concepts

NERC will address the key components of these changes in an informational filing made March 2013 to FERC. The key components include: (1) restyling the ERO's overall compliance approach to conform to well-established audit principles as described herein including the right to decline to pursue violations across the ERO Enterprise; (2) establishing the requirements for Regional Entity's records to facilitate NERC and FERC oversight; (3) establishing processes for information flow between compliance functions and enforcement functions as well as an open, transparent and clear approach as to which matters will be subject to enforcement procedures; and (4) redesigning the enforcement strategy to focus on serious or higher risks to the BES.

Presentations regarding these concepts and next steps will be made at the November NERC BOTCC, MRC and BOT meetings. In addition, there will be subsequent presentations at regularly scheduled meetings and supplemental webinars as needed to introduce and discuss the key change state elements and related activities. The ERO Enterprise anticipates that this model will mature and be fully deployed over the next three to five years.

The ERO Enterprise will also introduce these approaches through a pilot project[29] as the initial steps towards full implementation. FERC has previously recognized the value of pilot projects, pointing out that "[n]o matter how good the data suggesting that a regulatory change should be made, there is no substitute for reviewing the actual results of a regulatory action." Order No. 637, FERC Stats. & Regs. ¶ 31,091 (2000) at 31,279. The U.S. Court of Appeals for the D.C. Circuit agrees: "For at least 30 years this court has given special deference to agency development of such experiments, precisely because of the advantages of data developed in

[29]The pilot project will performed across and among the regions with ERO oversight in conjunction with selected registered entities, the results of which will be communicated as lessons learned in the overall development of the Compliance Enforcement Initiative.

the real world."[30] The goal of each pilot project will be to further define the risk-based approach and develop effective tools, training, procedures, and policies to allow the ERO Enterprise to deploy these concepts in a consistent manner across all Regional Entities. The ERO Enterprise will keep FERC apprised of the progress of the pilot projects, and at the conclusion of each pilot project, the ERO Enterprise will make appropriate revisions to the pilot projects and any necessary filings to deploy the pilot projects throughout the ERO Enterprise.

Beginning in November 2012 through early February 2013, NERC will be issuing a series of concept papers addressing the four key components described, the pilot project and a draft filing.

VI. Conclusion

The ERO Enterprise believes that the following benefits will result from employing risk-based methods:

- Improved Bulk Electric System reliability due to Registered Entities' enhancing their existing policies, processes and procedures; internal controls; and cultures of compliance that self-assess risk and compliance and promptly correct matters before they have a material impact on reliability.
- Improved standards development and retirement process because there is a compliance monitoring and enforcement feedback loop.
- Improved utilization of all participants' resources due to focus on higher risks.
- Increased efficiency for the ERO Enterprise and Registered Entities resulting in lower administrative costs because not all potential violations are processed.
- Drive consistency with the eight Regional Entities in compliance and enforcement.
- Improved Bulk Electric System reliability due to the use of the compliance monitoring and enforcement process to provide more meaningful signals about the ERO Enterprise's identified areas of concern and risk prioritization.

[30] *See, Interstate Natural Gas Association of America v. Federal Energy Regulatory Commission*, 285 F.3d 18, 24 (D.C. Cir. 2001)(http://ftp.resource.org/courts.gov/c/F3/285/285.F3d.18.00-1395.00-1380.00-1367.00-1360.00-1410.html)

From:	Quoc
To:	rsc
Cc:	dverner@nbpower.com; paul.difilippo@HydroOne.com; dbertagnolli@iso-ne.com
Subject:	FW: RCC Nov 2012 Meeting - TFSP Letter Regarding the NPCC Disturbance Monitoring Equipment Standard
Date:	Tuesday, November 20, 2012 2:58:08 PM
Attachments:	TFSP_Recommendations_PRC-002-NPCC-1_RCC_letter-Final.docx

Members, RSC

As requested by Mr. Verner, please see the attached FYI.

Thanks,
Quoc

From: Quoc
Sent: Tuesday, November 20, 2012 2:51 PM
To: Philip A. Fedora
Cc: dverner@nbpower.com; tfsp; Guy V. Zito; Lee R. Pedowicz; Gerard J. Dunbar
Subject: RCC Nov 2012 Meeting - TFSP Letter Regarding the NPCC Disturbance Monitoring Equipment Standard

Phil,

Attached, please find the TFSP letter regarding the NPCC Disturbance Monitoring Equipment Standard for the November 27, 2012 RCC Meeting.

Thanks,
Quoc

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A. Introduction

1. **Title:** **Disturbance Monitoring**

2. **Number:** PRC-002-NPCC-01

3. **Purpose:** Ensure that adequate disturbance data is available to facilitate Bulk Electric System event analyses. All references to equipment and facilities herein unless otherwise noted will be to Bulk Electric System (BES) elements.

4. **Applicability:**

   4.1. Transmission Owner

   4.2. Generator Owner

   4.3. Reliability Coordinator

5. **(Proposed) Effective Date:** To be established.

B. Requirements

R1. Each Transmission Owner and Generator Owner shall provide Sequence of Event (SOE) recording capability by installing Sequence of Event recorders or as part of another device, such as a Supervisory Control And Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control System (DCS) or part of Fault recording equipment. This capability shall: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island.

Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity.

1.2 Monitor the following at each location listed in 1.1:

1.2.1 Transmission and Generator circuit breaker positions

1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1.

1.2.3 Teleprotection keying and receive

R2. Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

2.1 All transmission lines.

2.2 Autotransformers or phase-shifters connected to busses.

2.3 Shunt capacitors, shunt reactors.

2.4 Individual generator line interconnections.

2.5 Dynamic VAR Devices.

2.6 HVDC terminals.

R3. Each Transmission Owner shall have Fault recording capability that determines the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R4. Each Generator Owner shall provide Fault recording capability for Generating Plants at and above 200 MVA Capacity and connected through a generator step up (GSU) transformer to a Bulk Electric System Element unless Fault recording capability is already provided by the Transmission Owner. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R5. Each Transmission Owner and Generator Owner shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

5.1 Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.)

5.2 Three phase currents and neutral currents.

5.3 Polarizing currents and voltages, if used.

5.4 Frequency.

5.5 Real and reactive power.

R6. Each Transmission Owner and Generator Owner shall provide Fault recording with the following capabilities: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

6.1 Each Fault recorder record duration shall be a minimum of one (1) second.

6.2 Each Fault recorder shall have a minimum recording rate of 16 samples per cycle

6.3 Each Fault recorder shall be set to trigger for at least the following:

6.3.1 Monitored phase overcurrents set at 1.5 pu or less of rated CT secondary current or Protective Relay tripping for all Protection Groups.

6.3.2 Neutral (residual) overcurrent set at 0.2 pu or less of rated CT secondary current.

6.3.3 Monitored phase undervoltage set at 0.85 pu or greater.

6.4 Document additional triggers and deviations from the settings in 6.3.2 and 6.3.3 when local conditions dictate.

R7. Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance Recording (DDR) capability that: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

7.1 Provides a minimum of 1 DDR per 3,000 MW of peak Load.

7.2 Records dynamic disturbance information with consideration of the following facilities/locations:

7.2.1 Major Load centers.

7.2.2 Major Generation clusters.

7.2.3 Major voltage sensitive areas.

7.2.4 Major transmission interfaces.

7.2.5 Major transmission junctions.

7.2.6 Elements associated with Interconnection Reliability Operating Limits (IROLs).

7.2.7 Major EHV interconnections between operating areas.

R8. Each Reliability Coordinator shall specify that DDRs installed, after the approval of this standard, function as continuous recorders. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R9. Each Reliability Coordinator shall specify that DDRs are installed with the following capabilities: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

9.1 A minimum recording time of sixty (60) seconds per trigger event.

9.2 A minimum data sample rate of 960 samples per second, and a minimum data storage rate for RMS quantities of six (6) data points per second.

9.3 Each DDR shall be set to trigger for at least one of the following (based on manufacturers' equipment capabilities):

9.3.1 Rate of change of Frequency.

9.3.2 Rate of change of Power.

9.3.3 Delta Frequency (recommend 20 mHz change).

9.3.4 Oscillation of Frequency.

R10. Each Reliability Coordinator shall establish requirements such that the following quantities are monitored or derived where DDRs are installed: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

10.1 Line currents for most lines such that normal line maintenance activities do not interfere with DDR functionality.

10.2 Bus voltages such that normal bus maintenance activities do not interfere with DDR functionality.

10.3 As a minimum, one phase current per monitored Element and two phase-to-neutral voltages of different Elements. One of the monitored voltages shall be of the same phase as the monitored current.

10.4 Frequency.

10.5 Real and reactive power.

R11. Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10, and

report this to the Regional Entity (RE) upon request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R12. Each Reliability Coordinator shall specify its DDR requirements including the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R13. Each Transmission Owner and Generator Owner that receives a request from the Reliability Coordinator to install a DDR shall acquire and install the DDR in accordance with R12. Reliability Coordinators, Transmission Owners, and Generator Owners shall mutually agree on an implementation schedule. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R14. Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

14.1 Maintenance and testing intervals and their basis.

14.2 Summary of maintenance and testing procedures.

14.3 Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)).

14.4 Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center).

14.5 Monthly verification of active analog quantities.

14.6 Verification of DDR and DFR settings in the software every six (6) years.

14.7 A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.

R15. Each Reliability Coordinator, Transmission Owner and Generator Owner shall share data within 30 days upon request. Each Reliability Coordinator, Transmission Owner, and Generator Owner shall provide recorded disturbance data from DMEs within 30 days of receipt of the request in each of the following cases: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

15.1 NERC, Regional Entity, Reliability Coordinator.

15.2 Request from other Transmission Owners, Generator Owners within NPCC.

R16. Each Reliability Coordinator, Transmission Owner and Generator Owner shall submit the data files conforming to the following format requirements: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

16.1 The data files shall be capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool as per the latest revision of IEEE Standard C37.111.

16.2 Disturbance Data files shall be named in conformance with the latest revision of IEEE Standard C37.232.

16.3 Fault Recorder and DDR Files shall contain all monitored channels. SOE records shall contain station name, date, time resolved to milliseconds, SOE point name, status.

R17. Each Reliability Coordinator, Transmission Owner and Generator Owner shall maintain, record and provide to the Regional Entity (RE), upon request, the following data on the DMEs installed to meet this standard: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

17.1 Type of DME.

17.2 Make and model of equipment.

17.3 Installation location.

17.4 Operational Status.

17.5 Date last tested.

17.6 Monitored Elements.

17.7 All identified channels.

17.8 Monitored electrical quantities.

C. Measures

M1. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Sequence of Event recording capability in accordance with 1.1 and 1.2. (R1)

M2. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 2.1 to 2.6. (R2)

M3. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability that determined the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements in accordance with R3.

M4. Each Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability for its Generating Plants at and above 200 MVA Capacity in accordance with R4.

M5. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it records for Faults, sufficient electrical quantities for each monitored Element to determine the parameters listed in 5.1 to 5.5. (R5)

M6. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 6.1 to 6.4. (R6)

M7. Each Reliability Coordinator shall have, and provide upon request, evidence that it established its area's requirements for Dynamic Disturbance Recording (DDR) capability in accordance with 7.1 and .2. (R7)

M8. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs installed after the approval of this standard function as continuous recorders. (R8)

M9. Each Reliability Coordinator shall have, and provide upon request, evidence that it developed DDR setting triggers to include the parameters listed in 9.1 to 9.3. (R9)

M10. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs monitor the Elements listed in 10.1 through 10.5. (R10)

M11. Each Reliability Coordinator shall have, and provide upon request, evidence that it documented additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10. (R11)

M12. Each Reliability Coordinator shall have, and provide upon request, evidence that it specified its DDR requirements which included the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners in the Reliability Coordinator's area. (R12)

M13. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it acquired and installed the DDRs in accordance with the specifications contained in the Reliability Coordinator's request, and a mutually agreed upon implementation schedule. (R13)

M14. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it has a maintenance and testing program for stand alone DME

(equipment whose only purpose is disturbance monitoring) that meets the requirements in 14.1 through 14.7. (R14)

M15. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided recorded disturbance data from DMEs within 30 days of the receipt of the request from the entities listed in 15.1 and 15.2. (R15)

M16. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it submitted the data files in a format that meets the requirements in 16.1 through 16.3. (R16)

M17. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it maintained a record of and provided to NPCC when requested, the data on DMEs installed meeting the requirements 17.1 through 17.8. (R17)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Transmission Owner and Generator Owner shall keep evidences for three calendar years for Measures 1, 5, 6, 13, 16 and 17.

The Transmission Owner shall keep evidence for three years for Measures 2 and 3.

The Generator Owner shall keep evidence for three years for Measure 4.

The Reliability Coordinator shall keep evidence for three years for Measures 7, 8, 9, 10, 11, 12, 16 and 17.

The Transmission Owner and Generator Owner shall keep evidences for twenty-four calendar months for Measures 14 and 15.

The Reliability Coordinator shall keep evidence for twenty-four calendar months for Measure 15.

If a Transmission Owner, Generator Owner or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit and all subsequent record.

1.4. Compliance Monitoring and Assessment Processes

- Self-Certifications
- Spot Checking
- Compliance Audits
- Self-Reporting
- Compliance Violation Investigations
- Complaints

1.5. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1 The Transmission Owner or Generator Owner provided the Sequence of Event recording capability meeting the bulk of R1 but missed…	Up to and including 10% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 10% and up to and including 20% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 20% and up to and including 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.
R2 The Transmission Owner provided the Fault recording capability meeting the bulk of R2 but missed…	Up to and including 10% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 10% and up to and including 20% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 20% and up to and including 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.
R3 The Transmission	Not applicable.	Not applicable.	Not applicable.	Fault recording capability that determines the

Owner failed to provide…				current zero time for loss of transmission Elements.
R4 The Generator Owner failed to provide Fault recording capability at…	Up to and including 10% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 10% and up to and including 20% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 20% and up to 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.
R5 The Transmission Owner or Generator Owner failed to record for the Faults…	Up to and including 10% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 10% and up to and including 20% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 20% and up to and including 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.
R6 The Transmission Owner or Generator Owner failed …	To provide Fault recording capability for up to and including 10% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1	To provide Fault recording capability for more than 10% and up to and including 20% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or	To provide Fault recording capability for more than 20% and up to and including 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in	To provide Fault recording capability for more than 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than ten (10) locations.

	through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for up to 2 locations.	deviations from the settings stipulated in 6.3 through 6.4 for more than two (2) and up to and including five (5) locations.	6.3 through 6.4 for more than five (5) and up to and including ten (10) locations.	
R7 The Reliability Coordinator failed to establish its area's requirements for…	Up to and including 10% of the required DDR coverage for its area as per 7.1and 7.2.	More than 10% and up to and including 20% of the required DDR coverage for its area as per 7.1 and 7.2.	More than 20% and up to and including 30% of the required DDR coverage for its area as per 7.1 and 7.2.	More than 30% of the required DDR coverage for its area as per 7.1 and 7.2.
R8 The Reliability Coordinator failed to specify that DDRs installed…	Not applicable.	Not applicable.	Not applicable.	Function as continuous recorders.
R9 The Reliability Coordinator failed to specify that DDRs are installed without…	Not applicable.	Not applicable.	Not applicable.	The capabilities listed in 9.1 through 9.3.
R10 The Reliability Coordinator failed to ensure that the quantities listed in 10.1 through 10.5 are monitored or derived…	Not applicable.	Not applicable.	Not applicable.	Where DDRs are installed.
R11 The Reliability Coordinator failed to document and report to the Regional Entity upon request additional settings and deviations from the required trigger settings described in R9	Up to two (2) facilities within the Reliability Coordinator's area that have a DDR.	More than two (2) and up to five (5) facilities within the Reliability Coordinator's area that have a DDR.	More than five (5) and up to ten (10) facilities within the Reliability Coordinator's area that have a DDR.	More than ten (10) facilities within the Reliability Coordinator's area that have a DDR.

and the required list of monitored quantities as described in R10 for…				
R12 The Reliability Coordinator failed to specify to the Transmission Owners and Generator Owners its DDR requirements including the DDR setting triggers established in R9 but missed…	Not applicable.	Not applicable.	Not applicable.	Established setting triggers.
R13 The Transmission Owner or Generator Owner failed to comply with the Reliability Coordinator's request installing the DDR in accordance with R12 for…	Up to and including 10% of the requirement set of the Reliability Coordinator's request to install DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 10% and up to 20% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 20% and up to 30% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 30% of the requirement set requested by the Reliability Coordinator and installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR OR The Reliability Coordinator, Transmission Owners, and Generator Owners failed to mutually agree on an implementation schedule.
R14 The Transmission Owner or Generator Owner…	Established a maintenance and testing program for stand alone DME but provided incomplete data for any one (1) of 14.1 through	Established a maintenance and testing program for stand alone DME but provided incomplete data for more than one (1) and up to and including three (3) of 14.1 through 14.7.	Established a maintenance and testing program for stand alone DME but provided incomplete data for more than three (3) and up to and including six (6) of 14.1 through 14.7.	Did not establish any maintenance and testing program for DME; OR The Transmission Owner or Generator Owner established a maintenance and testing program for DME but did not provide any data that

	14.7.			meets all of 14.1 through 14.7.
R15 The Reliability Coordinator, Transmission Owner or Generator Owner provided recorded disturbance data from DMEs but was late for…	Up to and including fifteen (15) days in meeting the requests of an entity, or entities in 15.1, or 15.2.	More than fifteen (15) days but less than and including thirty (30) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	More than 30 days but less than and including forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	More than forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.
R16 The Reliability Coordinator, Transmission Owner or Generator Owner failed to submit…	Up to and including two (2) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than two (2) and up to and including five (5) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than five (5) and up to and including ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.
R17 The Reliability Coordinator, Transmission Owner or Generator Owner failed to maintain or provide to the Regional Entity , upon request…	Up to and including two (2) of the items in 17.1 through 17.8.	More than two (2) and up to and including four (4) of the items in 17.1 to 17.8.	More than four (4) and up to and including six (6) of the items in 17.1 through 17.8.	More than six (6) of the items in 17.1 through 17.8.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	November 4, 2010	Adopted by NERC Board of Trustees	New
1	October 20, 2011	FERC Order issued approving PRC-002-NPCC-01 (FERC's Order became effective on October 20, 2011)	

Implementation Plan for PRC-002-NPCC-1

Disturbance Monitoring

Background

In developing the Implementation Plan for PRC-002-NPCC-1 the Standard Drafting Team considered the following:

1. The requirements listed in this Regional Standard are intended to cover all aspects of the utilization of Disturbance Monitoring equipment. The intent of the Standard is to be more stringent than the continent wide Standard under development at NERC. After the approved NERC continent wide Standard is issued, PRC-002-NPCC-1 will be revisited to eliminate any redundancies.

2. The refueling outage schedules of nuclear plants will be considered when determining their compliance.

3. Any implementation plan will be impacted by the resource availability and approval processes of the Reliability Coordinators, Transmission Owners, and Generator Owners.

4. It is assumed the Reliability Coordinators have already established their DDR needs. If not, "time zero" will be after the Reliability Coordinator issues the locations and needs for additional DDR equipment.

Effective Dates

1. Within two (2) years of FERC and Canadian entities' approvals, entities shall be 50 percent compliant at facilities required to have DME capabilities by:

   a. Installing Sequence of Events (SOE) capability at 50 percent of the facilities that previously had no SOE capability (percent complete will be based on the number of facilities completed)

   b. Installing additional SOE capability to facilities with existing SOEs such that 50 percent of the total required capability is complete (percent complete will be based on the number of SOE points required)

   c. Installing Fault Recording capability at 50 percent of the facilities that previously had no Fault Recording capability (percent complete will be

based on the number of facilities completed)

d. Installing additional Fault Recording capability to facilities with existing Fault Recording capability such that 50 percent of the required capability is complete (percent complete will be based on the number of traces required)

e. Installing Dynamic Disturbance Recording (DDR) capability at 50 percent of the facilities that previously had no DDR capability (percent complete will be based on the number of facilities completed versus those required by the Reliability Coordinator)

f. Installing additional DDR capability to facilities with existing DDR capability such that 50 percent of the required capability is complete (percent complete will be based on the number of elements as required by the Reliability Coordinator)

2. Within three (3) years of FERC and Canadian entities' approvals, entities shall be 75 percent compliant at facilities required to have DME capabilities by:

a. Installing SOE capability at 75 percent of the facilities that previously had no SOE capability (percent complete will be based on the number of facilities completed)

b. Installing additional SOE capability to facilities with existing SOEs such that 75 percent of the total required capability is complete (percent complete will be based on the number of SOE points required)

c. Installing Fault Recording capability at 75 percent of the facilities that previously had no Fault Recording capability (percent complete will be based on the number of facilities completed)

d. Installing additional Fault Recording capability to facilities with existing Fault Recording capability such that 75 percent of the required capability is complete (percent complete will be based on the number of traces required)

e. Installing DDR capability at 75 percent of the facilities that previously had no DDR capability (percent complete will be based on the number of facilities completed versus those required by the Reliability Coordinator)

f. Installing additional DDR capability to facilities with existing DDR capability such that 75 percent of the required capability is complete (percent complete will be based on the number of elements as required by the Reliability Coordinator)

3. Within four (4) years of FERC and Canadian entities' approvals, all (100 percent) SOE, Fault Recording, and DDR capability shall be installed to satisfy the requirements of this Standard.

Reference

NPCC Criteria:

A-5 Bulk Power System Protection Criteria

A-7 NPCC Glossary of Terms

A-10 Classification of Bulk Power System Elements

A-15 Disturbance Monitoring Equipment Criteria

NPCC Guides:

B-26 Guide for Application of Disturbance Recording Equipment

B-28 Draft Guideline for Generator Sequence of Event Monitoring

SP-6 Synchronized Event Data Reporting

A NPCC Directory will be developed for Disturbance Monitoring. It will contain supporting information and details from the Criteria and Guides that are not incorporated in the Standard.

Version History

Version	Date	Action	Change Tracking
1	January 6, 2010	Approved by NPCC Membership	
1	February 9, 2010	Approved by NPCC Board of Directors	
1	November 4, 2010	Approved by NERC Board of Trustees	
1	October 20, 2011	FERC Order issued approving PRC-002-NPCC-1 and its Implementation Plan	

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November 20, 2012

Members, Reliability Coordinating Committee
Messrs: Harvey J. Reed
Edward A. Schwerdt

Re: TFSP Response to the RCC request for clarification to NPCC Disturbance Monitoring Regional Standard PRC-002-NPCC-01 as it pertains to the changes to the BES definition and the resulting applicability expansion beyond the original intent.

Ladies and Gentlemen:

At the September 2012 Reliability Coordinating Committee (RCC) meeting, the RCC gave direction to the Task Force on System Protection (TFSP) to explore the possibility of providing an interpretation document which could stand with the existing approved NPCC regional standard. This would provide an avenue around (without going through the standards review process) the tremendous cost that would be borne by the member entities in the NPCC region due to the modification to definition of the term "BES".

At the September, 2012 meeting, the TFSP discussed the topic at length, coming to the conclusion, that the technical aspects of the document were sound with no avenue for any different interpretation. As a result, TFSP would like to review some previous statements made and put forth two actionable items for the RCC.

In regards to the expanded applicability resulting from the definition change, the TFSP does not support the automatic expanded applicability of PRC-002-NPCC-1 Standard to all facilities as defined by the NERC approved revised BES definition for the following reasons:

1. The standard's applicability to non-BPS facilities is not supported by the original SP-6 Technical Report.
2. There was a prior understanding by all involved in the development and approval of PRC-002-NPCC-1 that any future revision to the BES definition would necessitate a review and revision to this Standard based upon the final definition of the BES.
3. The cost associated with applying PRC-002-NPCC-1 to all facilities as defined by the NERC approved revised BES definition is prohibitive, unjustifiable, and places an undue burden on the entities in terms of financial and human resources. Without due regard given to the impact of the standard by the revised BES definition, this standard

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will no longer meet cost effectiveness requirements and will likely result in members spending less on other reliability improvements such as relay replacements.

Table 1 below provides the RCC with the estimated capital installation costs alone for several member utilities. Included in these costs are the engineering, construction, and test resources required for these installations. There will also be additional costs involved to provide the necessary communications to some of the smaller and more remote substations (where communications are not presently available) for physical retrieval of records, and additional equipment needed for archiving all the additional records. In addition, from an O&M perspective, there will be significant ongoing engineering and field testing resources required to accomplish the periodic verification, collection, analysis, and archival of the volumes of data that will be created. There will also be additional control center, ISO and field testing resources required to make application, schedule the outage, if necessary, and perform periodic maintenance tests and repair of the additional equipment. In many cases, this will result in the need for entity to add one or more additional full time employee to perform this work.

Table 1 – Estimated Capital Installation Costs if PRC-002-NPCC-1 Standard is Mandated to All BES Facilities as defined by the NERC Revised BES Definition

UTILITY	ADDITIONAL BES FACILITIES	INSTALLATION COST in MILLION
HYDRO ONE	51	$20
NGRID	100	$25
NU (Including NSTAR)	122	$41
UI	16	$1
CMP, NYSEG,RG&E	142	$57
Con Ed	196	$23
NBPT	15	$2

In addition, TFSP notes the following:

1. There is an underlying flaw in the NPCC process which allows for a change to a critical glossary term used in standards without a resulting review of the standards which utilize the term.
2. It appears that the RSAR procedure as defined in the Regional Reliability Standard Development Procedure is unclear or is not being followed. Attempts by one member entity to have an RSAR processed have been unsuccessful due to an apparent requirement that there

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be technical justification for an RSAR modification request, there is no mention of this requirement in the NPCC procedure document.

The TFSP acknowledges that the approved PRC-002-NPCC-1 standard is an extremely comprehensive and will ensure the adequate monitoring of all BPS facilities in the NPCC region. Indeed it would be advantageous for all electrical facilities, regardless of importance on the electrical grid, to be subject to the requirements set out in this standard. Realistically though, the resulting cost for accomplishing this would be excessive and is only used here to illustrate the TFSP assertion that the cost effective application of standards is a critical component in a reliability organizations mandate.

In summary, what must be recognized and given proper consideration is the impact on standards when an underlying definition of a defined term used in standards is modified.

As stipulated in the NPCC Regional Reliability Standards Development Process Document, the RCC "will also provide a technical advisory role in the Regional Reliability Standards development procedure through recommendations."

The TFSP requests the following action items to be taken by the RCC:

1. Advise RSC that an RSAR should be approved to review and revise PRC-002-NPCC-1 immediately to clarify the intended applicability of the standard in light of the new NERC approved BES definition. To accomplish this objective, the NPCC RSC staff position of requiring a technical justification for a RSAR must be waived in lieu of a cost effectiveness justification. Once a Standards Drafting Team has been convened, the TFSP recommends that the applicability of the standard be expanded beyond the present definition of BES in the NPCC region (A10 testing) to comply with the intent of the approved NERC BES definition.

2. Advise RSC that NPCC process changes be investigated to ensure NPCC specific standards utilizing defined terms, that undergo a revision, be reviewed by the applicable Task Force who are the subject matter experts for the affected standard. If that Task Force sees the need for a revision, an RSAR should be initiated to make changes to the standard.

The Task Force on System Protection respectively requests your support for the above recommendations as a way for NPCC to formally address the issue.

I will be available at the November 27, 2012 RCC meeting to review with you the above recommendation.

NPCC, Inc.

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Yours very truly,

Daren

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NPCC
Regional Reliability Reference Directory # 1
Design and Operation of the Bulk Power System

Task Force on Coordination of Planning Revision Review Record:
December 01, 2009

Adopted by the Members of the Northeast Power Coordinating Council, Inc., on December 01, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

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Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0			**New**
1	**4/20/2012**	**Errata changes in Appendix B and Appendix E.**	**Errata**

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1.0 Introduction

1.1 Title - Design and Operation of the Bulk Power System

1.2 Directory Number 1

1.3 Objective

The objective of these criteria is to provide a "design-based approach" to ensure the **bulk power system** is designed and operated to a level of reliability such that the loss of a major portion of the system, or unintentional separation of a major portion of the system, will not result from any design **contingencies** referenced in Sections 5.4.1 and 5.4.2. In NPCC the technique for assuring the reliability of the **bulk power system** is to require that it be designed and operated to withstand representative **contingencies** as specified in this Directory. Analyses of simulations of these **contingencies** include assessment of the potential for widespread cascading outages due to overloads, instability or voltage collapse. Loss of small portions of a system (such as radial portions) may be tolerated provided these do not jeopardize the reliability of the remaining **bulk power system**.

Criteria described in this document are to be used in the design and operation of the **bulk power system.** These criteria are applicable to all entities which are part of or make use of the **bulk power system**.

The characteristics of a reliable **bulk power system** include adequate **resources** and transmission to reliably meet projected customer electricity demand and energy requirements as prescribed in this document and include:

a. Consideration of a balanced relationship among the fuel type, capacity, physical characteristics (peaking/base **load**/etc.), and location of **resources**.

b. Consideration of a balanced relationship among transmission system **elements** to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.

c. Transmission systems should provide flexibility in switching arrangements, voltage control, and other control measures

1.4 Effective Date - December 01, 2009

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1.5 Background

This Directory was developed from the NPCC A-2 criteria document - Basic Criteria for the Design and Operation of Interconnected Power Systems (May 6, 2004 version). Guidelines and Procedures for consideration in the implementation of this Directory are provided in the Appendices.

1.6 Applicability

1.6.1 Functional Entities

Reliability Coordinators
Transmission Operators
Balancing Authorities
Planning Coordinators
Transmission Planners
Resource Planners

2.0 Terms Defined in this Directory

Terms appearing in bold typeface in this Directory (including the Appendices) are defined in Appendix A.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing requirements that are associated with this Directory include, but may not be limited to:

3.1 EOP-001-0 - Emergency Operations Planning
3.2 FAC-011-2 - System Operating Limits Methodology for the Operations Horizon
3.3 IRO-002-1 - Reliability Coordination - Facilities
3.4 IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
3.5 MOD-010-0 - Steady-State Data for Transmission System Modeling and Simulation
3.6 MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
3.7 MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation
3.8 MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures
3.9 MOD-014-0 — Development of Interconnection-Specific Steady State System Models
3.10 MOD-015-0 — Development of Interconnection-Specific Dynamics System Models
3.11 MOD-016-1 — Actual and Forecast Demands, Net Energy for Load,

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Controllable DSM

3.12 TOP-001-1 — Reliability Responsibilities and Authorities
3.13 TOP-002-2 — Normal Operations Planning
3.14 TOP-003-0 — Planned Outage Coordination
3.15 TOP-004-2 — Transmission Operations
3.16 TPL-001-0 — System Performance Under Normal Conditions
3.17 TPL-002-0 — System Performance Following Loss of a Single BES Element NPCC Regional Reliability Standard Requirements
3.18 TPL-003-0 — System Performance Following Loss of Two or More BES Elements
3.19 TPL-004-0 — System Performance Following Extreme BES Events
3.20 TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports
3.21 TPL-006-0 — Assessment Data from Regional Reliability Organizations
3.22 VAR-001-1 — Voltage and Reactive Control

4.0 NPCC regional Reliability Standards Requirements

None

5.0 NPCC Full Member, More Stringent Criteria

NPCC provides a forum for coordinating the design and operations of its five Reliability Coordinator Areas. NPCC shall conduct regional and interregional studies, and assess and monitor Planning Coordinator Area studies and Reliability Coordinator operations to assure conformance to these criteria through committees, task forces, and working groups.

It is the responsibility of each Reliability Coordinator to ascertain that their portion of the **bulk power system** is operated in conformance with these criteria. It is the responsibility of each Transmission Planner and Planning Coordinator to ascertain that their portion of the **bulk power system** is designed in conformance with these criteria

5.1 General Requirements

Specific system conditions may require Planning Coordinators or Reliability Coordinators to develop criteria which are more stringent than those set out herein. Any constraints imposed by these more stringent criteria will be observed. It is also recognized that these Criteria are not necessarily applicable to those **elements** that are not a part of the **bulk power system** or in the portions of a system where instability or overloads will not jeopardize the reliability of the remaining **bulk power system.**

5.1.1 Design Criteria

These design criteria will be used in the assessment of the **bulk power system** by each of the NPCC Transmission Planners and Planning Coordinators, and in the reliability testing at the Transmission Operator, Reliability Coordinator and Regional Council levels.

Design studies shall assume **power** flow conditions utilizing transfers, **load** and generation conditions which stress the system. Transfer capability studies shall be based on the **load** and generation conditions expected to exist for the period under study. All **reclosing** facilities shall be assumed in service unless it is known that such facilities will be rendered inoperative.

S**pecial protection systems (SPS)** shall be used judiciously and when employed shall be installed, consistent with good system design and operating criteria found in Directory #7 – *Special Protection Systems*.

A SPS may be used to provide protection for infrequent **contingencies**, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. A **SPS** may also be applied to preserve system integrity in the event of severe facility outages and extreme **contingencies.** The decision to employ a **SPS** shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.

The requirements of **special protection systems** are defined in the NPCC *Bulk Power System Protection Criteria*, (Directory#4), and the *Special Protection Systems*, (Directory #7).

5.1.2 Operating Criteria

Coordination among and within the Reliability Coordinator Areas of NPCC is essential to the reliability of interconnected operations. Timely information concerning system conditions shall be transmitted by the NPCC Reliability Coordinators to other NPCC Reliability Coordinators, adjacent Reliability Coordinators or other entities as needed to assure reliable operation of the **bulk power system**.

The operating criteria represent the application of the design criteria to inter-Reliability Coordinator Area, intra- Reliability Coordinator Area operation.

The operating criteria define the minimum level of reliability that shall apply to inter-Reliability Coordinator Area operation. Where inter-Reliability Coordinator Area reliability is affected, each Reliability

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Coordinator shall establish limits and operate so that the **contingencies** stated in Section 5.5.1 and 5.5.2 can be withstood without causing a **significant adverse impact** on other Reliability Coordinator Areas.

When adequate **bulk power system** facilities are not available, **special protection systems** (SPS) may be employed to maintain system security.

Two categories of transmission transfer capabilities, normal and **emergency**, are applicable. Normal transfer capabilities are to be observed unless an **emergency** is declared.

5.1.3 Data Exchange Requirements for Modeling and System Analysis

It is the responsibility of NPCC and NPCC Members to protect the proprietary nature of the following information and to ensure it is used only for purposes of efficient and reliable system design and operation. Also, any sharing of such information must not violate anti-trust laws.

For reliability purposes, Reliability Coordinators shall share and coordinate forecast system information and real time information to enable and enhance the analysis and modeling of the interconnected **bulk power system** by security application software on energy management systems. Each Registered Entity within an NPCC Reliability Coordinator Area shall provide needed information to its Reliability Coordinator as required. Analysis and modeling of the interconnected power system is required for reliable design and operation. Data needed to analyze and model the electric system and its component facilities must be developed, maintained, and made available for use in interconnected operating and planning studies, including data for fault level analysis.

Reliability Coordinators and Registered Entities shall maintain and submit, as needed, data in accordance with applicable NPCC Procedures.

Data submitted for analysis representing physical or control characteristics of equipment shall be verified through appropriate methods. System analysis and modeling data must be reviewed annually, and verified on a periodic basis. Generation equipment, and its component controllers, shall be tested to verify data.

5.2 Resource Adequacy – Design Criteria

The probability (or risk) of disconnecting **firm load** due to resource deficiencies shall be, on average, not more than one day in ten years as

determined by studies conducted for each Resource Planning and Planning Coordinator Area. Compliance with this criterion shall be evaluated probabilistically, such that the loss of **load** expectation (LOLE) of disconnecting **firm load** due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or **load** relief from available operating procedures.

5.3 Resource Adequacy – Operating Criteria

Each Balancing Authority shall have procedures in place to schedule outages and deratings of **resources** in such a manner that the available **resources** will be adequate to meet the Resource Planner's and Planning Coordinator's forecasted demand and **reserve** requirements, in accordance with the NPCC *Operating Reserve Criteria* (Directory#5).

For consistent evaluation and reporting of **resource** adequacy, it is necessary to measure the net capability of generating units and **loads** utilized as a **resource** of each Planning Coordinator Area.

5.4 Transmission Design Criteria

The portion of the **bulk power system** in each Planning Coordinator Area and in each Transmission Planning Area shall be designed with sufficient transmission capability to serve forecasted demand under the conditions noted in Sections 5.4.1 and 5.4.2. These criteria will also apply after any critical generator, transmission circuit, transformer, series or shunt compensating device or HVdc pole has already been lost, assuming that the Planning Coordinator Area generation and **power** flows are adjusted between outages by the use of **ten-minute reserve** and where available, phase angle regulator control and HVdc control.

Anticipated transfers of **power** from one Planning Coordinator Area to another, as well as within Planning Coordinator Areas, shall be considered in the design of transmission facilities. Transmission transfer capabilities shall be determined in accordance with the conditions noted in Sections 5.4.1 and 5.4.2.

5.4.1 Stability Assessment

Stability of the **bulk power system** shall be maintained during and following the most severe of the **contingencies** stated below, with due regard to **reclosing**. For each of the **contingencies** below that involve a fault, **stability** shall be maintained when the simulation is based on

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fault clearing initiated by the **"system A" protection group**, and also shall be maintained when the simulation is based on **fault clearing** initiated by the **"system B" protection group**.

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section with **normal fault clearing**.

b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with **normal fault clearing**. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the Reliability Coordinating Committee specifically accepts each request for exclusion.

c. A permanent phase to ground fault on any transmission circuit, transformer, or bus section with **delayed fault clearing**.

d. Loss of any **element** without a fault.

e. A permanent phase to ground fault on a circuit breaker with **normal fault clearing**. (**Normal fault clearing** time for this condition may not always be high speed.)

f. Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault

g. The failure of a circuit breaker to operate when initiated by a **SPS** following: loss of any **element** without a fault; or a permanent phase to ground fault, with **normal fault clearing**, on any transmission circuit, transformer or bus section.

5.4.2 Steady State Assessment

a. Each Transmission Planner shall design its system in accordance with these criteria and its own voltage control procedures and criteria, and coordinate these with adjacent Transmission Planner Areas**.** Adequate **reactive power** resources and appropriate controls shall be installed in each Transmission Planner Area to maintain voltages within

normal limits for pre-**disturbance** conditions, and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in 5.4.1.

b. Line and equipment loadings shall be within normal limits for pre-**disturbance** conditions and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in 5.4.1.

5.4.3 Fault Current Assessment

Each Transmission Planner and Planning Coordinator shall establish procedures and implement a system design that ensures equipment capabilities are adequate for fault current levels with all transmission and generation facilities in service for all potential operating conditions, and coordinate these procedures with adjacent Planning Coordinator Areas.

5.5 Transmission Operating Criteria

Scheduled outages of facilities that affect inter-Reliability Coordinator Area reliability shall be coordinated sufficiently in advance of the outage to permit the affected Reliability Coordinators to maintain reliability. Each Reliability Coordinator shall notify adjacent Reliability Coordinators of scheduled or forced outages of any facility on the NPCC Transmission Facilities Notification List and of any other condition which may impact on inter-Reliability Coordinator Area reliability. Work on facilities which impact inter-Reliability Coordinator Area reliability shall be expedited to minimize the time that the facilities are out of service.

Individual Reliability Coordinator Areas shall be operated in a manner such that the **contingencies** noted in Section 5.5.1 and 5.5.2 can be withstood and do not adversely affect other Reliability Coordinator Areas.

Appropriate adjustments shall be made to Reliability Coordinator Area operations to accommodate the impact of **protection group** outages, including the outage of a **protection group** which is part of a Type I **special protection system**. For typical periods of forced outage or maintenance of a **protection group**, it can be assumed, unless there are indications to the contrary, that the remaining **protection** will function as designed. If the **protection group** will be out of service for an extended period of time, additional adjustments to operations may be appropriate considering other system conditions and the consequences of possible failure of the remaining **protection group**.

5.5.1 Normal Transfers

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Pre-**contingency** voltages, line and equipment loadings shall be within normal limits. Unless specific instructions describing alternate action are in effect, normal transfers shall be such that manual **reclosing** of a faulted **element** can be carried out before any manual system adjustment, without affecting the **stability** of the **bulk power system**.

Stability of the **bulk power system** shall be maintained during and following the most severe of the **contingencies** stated below, with due regard to **reclosing.** For each of the **contingencies** stated below that involves a fault, **stability** shall be maintained when the simulation is based on **fault clearing** initiated by the **"system A" protection group**, and also shall be maintained when the simulation is based on **fault clearing** initiated by the **"system B" protection group**.

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with **normal fault clearing**.

b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with **normal fault clearing**. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the Reliability Coordinating Committee specifically accepts each request for exclusion.

c. A permanent phase to ground fault on any transmission circuit, transformer, or bus section with **delayed fault clearing**.

d. Loss of any **element** without a fault.

e. A permanent phase to ground fault on a circuit breaker, with **normal fault clearing**. (**Normal fault clearing** time for this condition may not always be high speed.)

f. Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault.

g. The failure of a circuit breaker to operate when initiated by a **SPS** following: loss of any **element**

without a fault; or a permanent phase to ground fault, with **normal fault clearing**, on any transmission circuit, transformer or bus section.

Reactive power resources shall be maintained in each Reliability Coordinator Area in order to maintain voltages within normal limits for pre-**disturbance** conditions, and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in the foregoing. Adjoining Reliability Coordinators shall mutually agree upon procedures for inter-Reliability Coordinator Area voltage control.

Line and equipment loadings shall be within normal limits for pre-**disturbance** conditions and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in the foregoing.

Since **contingencies** b, c, e, f, and g, are not confined to the loss of a single **element**, individual Transmission Operators and Reliability Coordinators may choose to permit a higher post **contingency** flow on remaining facilities than for **contingencies** a and d. This is permissible providing operating procedures are documented to accomplish corrective actions; the loadings are sustainable for at least the anticipated time required to effect such action, and other Transmission Operator Areas or Reliability Coordinator Areas will not be subjected to the higher flows without prior agreement.

5.5.2 Emergency Transfers

When **firm load** cannot be supplied within normal limits in a Transmission Operator Area, or a portion of a Transmission Operator Area, transfers may be increased to the point where pre-**contingency** voltages, line and equipment loadings are within **applicable emergency limits**. **Emergency** transfer levels may require generation adjustment before manually **reclosing** faulted **elements**.

Stability of the **bulk power system** shall be maintained during and following the most severe of the following **contingencies**, and with due regard to **reclosing**:

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with **normal fault clearing**.

b. The loss of any **element** without a fault.

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Immediately following the most severe of these **contingencies**, voltages, line and equipment loadings will be within **applicable emergency limits**.

5.5.3 Post Contingency Operation

Immediately after the occurrence of a **contingency**, the status of the **bulk power system** must be assessed and transfer levels must be adjusted, if necessary, to prepare for the next **contingency**. If the readjustment of generation, **load** resources, phase angle regulators, and direct current facilities is not adequate to restore the system to a secure state, then other measures such as voltage reduction and shedding of firm **load** may be required. System adjustments shall be completed as quickly as possible, but in all cases within 30 minutes after the occurrence of the **contingency**.

Voltage reduction need not be initiated and firm **load** need not be shed to observe a post **contingency** loading requirement until the **contingency** occurs, provided that adequate response time for this action is available after the **contingency** occurs and other measures will maintain post **contingency** loadings within **applicable emergency limits**.

Emergency measures, including the pre-**contingency** disconnection of **firm load** if necessary, must be implemented to limit transfers to within the requirements of 5.5.2 above.

5.5.4 Operation under High Risk Conditions

Operating to the **contingencies** listed in Sections 5.5.1 and 5.5.2 is considered to provide an acceptable level of **bulk power system** security. Under certain unusual conditions, such as severe weather, the expectation of occurrence of some **contingencies**, and the associated consequences, may be judged to be temporarily, but significantly, greater than the long-term average expectation. When these conditions, referred to as high risk conditions, are judged to exist in a Transmission Operator Area, consideration should be given to operating in a more conservative manner than that required by the provisions of Sections 5.5.1 and 5.5.2.

5.6 Extreme Contingency Assessment

Extreme **contingency** assessment recognizes that the **bulk power system** can be subjected to events which exceed, in severity, the **contingencies** listed in Section 5.4.1. One of the objectives of extreme **contingency** assessment is to

determine, through planning studies, the effects of extreme **contingencies** on system performance. This is done in order to obtain an indication of system strength, or to determine the extent of a widespread system **disturbance**, even though extreme **contingencies** do have low probabilities of occurrence.

The specified extreme **contingencies** listed below are intended to serve as a means of identifying some of those particular situations that could result in a widespread **bulk power system disturbance**. It is the responsibility of each Planning Coordinator Area to identify any additional extreme **contingencies** to be assessed.

Assessment of the extreme **contingencies** listed below shall examine post **contingency** steady state conditions, as well as **stability**, overload, cascading outages and voltage collapse. Pre-**contingency load** flows chosen for analysis shall reflect reasonable **power** transfer conditions within or between Planning Coordinator Areas.

Analytical studies shall be conducted to determine the effect of the following extreme **contingencies**:

a. Loss of the entire capability of a generating station.

b. Loss of all transmission circuits emanating from a generating station, switching station, dc terminal or substation

c. Loss of all transmission circuits on a common right-of-way.

d. Permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, with **delayed fault clearing** and with due regard to **reclosing**.

e. The sudden dropping of a large **load** or major **load** center.

f. The effect of severe **power** swings arising from **disturbances** outside the Council's interconnected systems.

g. Failure of a **special protection system**, to operate when required following the normal **contingencies** listed in Section 5.4.1.

h. The operation or partial operation of a **special protection system** for an event or condition for which it was not intended to operate.

i. Sudden loss of fuel delivery system to multiple plants, (i.e. gas pipeline **contingencies**, including both gas transmission lines and gas mains.)

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Note: The requirement of this section is to perform extreme **contingency** assessments. In the case where extreme **contingency** assessment concludes there are serious consequences, an evaluation of implementing a change to design or operating practices to address such **contingencies** shall be conducted.

5.7 Extreme System Conditions Assessment

The **bulk power system** can be subjected to wide range of other than normal system conditions that have low probability of occurrence. One of the objectives of extreme system conditions assessment is to determine, through planning studies, the impact of these conditions on expected steady-state and dynamic system performance. This is done in order to obtain an indication of system robustness or to determine the extent of a widespread system **disturbance**. Each Transmission Planner and Planning Coordinator has the responsibility to incorporate special simulation testing to assess the impact of extreme system conditions.

Analytical studies shall be conducted to determine the effect of design **contingencies** under the following extreme conditions:

a. Peak **load** conditions resulting from extreme weather conditions with applicable **rating** of electrical **elements**.

b. Generating unit(s) fuel shortage, (i.e. gas supply adequacy)

After due assessment of extreme system conditions, measures may be utilized, where appropriate, to mitigate the consequences that are indicated as a result of testing for such system conditions. .

Prepared by: Task Force on Coordination of Planning

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.

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Revisions pertaining to the Appendices or any other portion of the document such as Links glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References:

NPCC Glossary of Terms
Bulk Power System Protection Criteria (Directory#4)
Emergency Operations (NPCC Directory #2)
Special Protection Systems (Directory #7))

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Appendix A - Definition of Terms

Applicable emergency limits - These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitations, etc.

Emergency limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes.

The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system **stability** performance, and should not adversely affect the operation of the **bulk power system**.

The limiting condition for equipment loadings should be such that cascading outages will not occur due to operation of protective devices upon the failure of facilities. (Various definitions of equipment **ratings** are found elsewhere in this glossary.)

Bulk power system - The interconnected electrical systems within north-eastern North America comprising **generation** and transmission facilities on which **faults** or **disturbances** can have a **significant adverse impact** outside of the local area. In this context, local areas are determined by the Council members.

Contingency - An event, usually involving the loss of one or more **elements,** which affects the **power** system at least momentarily.

NPCC Specific Definitions:

NPCC Emergency Criteria **Contingencies** - The set of **contingencies** to be observed when operating the **bulk power system** under **emergency** conditions. (Document C-1; also reference Document A-2, Section 6.2 - Emergency Transfers.)

NPCC Normal Criteria **Contingencies** - The set of **contingencies** to be observed when operating the **bulk power system** under normal conditions. (Document C-1; also reference Document A-2, Section 6.1 - Normal Transfers.)

Double Element Contingency - A **contingency** which involves the loss of two **elements**. (Document C-1)

Single Contingency - A single event which may result in the loss of one or more **elements.**

Single Element Contingency - A **contingency** involving the loss of one **element**. (Document C-1)

Limiting Contingency - The **contingency** which establishes the **transfer capability**. (Document C-1)

First Contingency Loss - The largest **capacity** outage including any assigned Ten-Minute Reserve which would result from the loss of a single **element** (Documents A-6 and C-1)

Second Contingency Loss - The largest **capacity** outage which would result from the loss of a single **element** after allowing for the First Contingency Loss. (Documents A-6 and C-1)

Disturbance - Severe oscillations or severe step changes of current, voltage and/or frequency usually caused by **faults**.

System Disturbance - An event characterized by one or more of the following phenomena: the loss of **power** system **stability**; cascading outages of circuits; oscillations; abnormal ranges of frequency or voltage or both.

Element - Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section.

Limiting Element - The element that is either operating at its appropriate **rating** or would be, following a limiting **contingency** and, as a result, establishes a system limit.

Emergency - Any abnormal system condition that requires automatic or manual action to prevent or limit loss of transmission facilities or **generation** supply that could adversely affect the **reliability** of the electric system.

Specific to NPCC: An **Emergency** is considered to exist in an Area if **firm load** may have to be shed.

Fault Clearing

Delayed fault clearing - Fault clearing consistent with correct operation of a breaker failure **protection group** and its associated breakers, or of a backup **protection group** with an intentional time delay.

High speed fault clearing - Fault clearing consistent with correct operation of high speed relays and the associated circuit breakers without intentional time delay.
Notes: The specified time for high-speed relays in present practice is 50 milliseconds (three cycles on a 60Hz basis) or less. [IEEE C37.100-1981]. For planning purposes, a total clearing time of six cycles or less is considered high speed.

Normal fault clearing - Fault clearing consistent with correct operation of the **protection system** and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that **protection system**.

Load - The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

NPCC Specific Definitions:

Firm Load - Loads that are not **Interruptible Loads**.

Interruptible Load - Loads that are interruptible under the terms specified in a contract.

Power

Apparent Power - The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilovoltamperes (kVA) or megavoltamperes (MVA).

Reactive Power - The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVAr).

Real Power - The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

Protection - The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.

Protection group - A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups.

Notes:
(a) Variously identified as Main Protection, Primary Protection, Breaker Failure Protection, Back-Up Protection, Alternate Protection, Secondary Protection, A Protection, B Protection, Group A, Group B, System 1 or System 2.

(b) Pilot protection is considered to be one protection group. Protection system
Element Basis One or more protection groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete protection of that **element**.

Terminal Basis
One or more protection groups, as above, installed at one terminal of a power system **element**, typically a transmission line.

Pilot Protection - A form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line.

Rating - The operational limits of an electric system, facility, or **element** under a set of specified conditions.

Reclosing

Autoreclosing - The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker. Autoreclosing does not include automatic closing of capacitor or reactor circuit breakers.

High-speed autoreclosing - The autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle.

Manual Reclosing - The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised.

Supervision- A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., **synchronism-check**).

Synchronism-check - refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.

Relay - An electrical device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).

Reliability - The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — **Adequacy** and **Security**.

Adequacy — The ability of the electric system to supply the aggregate electrical **demand** and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system **elements**.

Security — The ability of the electric system to withstand **disturbances** such as electric **short circuits** or unanticipated loss of system **elements**.

Reserve - In normal usage, reserve is the amount of **capacity** available in excess of the **demand**

Reserve Requirement - That capability above firm system **demand** required to provide for regulation, **load** forecasting error, equipment forced and scheduled outages, and local area supply **adequacy**

NPCC Specific Definitions:

Non-Synchronized Reserve — That portion of operating capacity which is available by synchronizing a generator to the network, and that capacity which can be made available by reducing load that is dependent on starting a generator to replace energy that is supplied from the grid. Non-Synchronized Reserve also includes the capacity achieved through the implementation of voltage reduction. (Documents A-6 and C-1)

Operating Reserve - The sum of **ten-minute** and **thirty-minute reserve**. (Documents A-3, A-6, and A-1)

Reserve on **Automatic Generation Control (AGC)** - That portion of **synchronized reserve** which is under the command of an automatic controller to respond to **load demands** without need for manual action. (Documents A-6 and C-1)

Synchronized Reserve - The unused capacity from resources that are synchronized to the system and ready to achieve claimed capacity (Documents A-6 and C-1)

Ten-minute reserve - The sum of **synchronized** and **non-synchronized reserve** that is fully available in ten minutes. (Documents A-6 and C-1)

Thirty-Minute Reserve - The sum of synchronized and non-synchronized reserve that can be utilized within thirty minutes of receiving an activation request, excluding capacity assigned to ten minute reserve. (A-6, C-1)

Resource - Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load.

Significant adverse impact - With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from **faults** or **disturbances**, shall be deemed as having **significant adverse impact**:

a. instability:
- any instability that cannot be demonstrably contained to a well defined local area,
- any loss of synchronism of generators that cannot be demonstrably contained to a well-defined local area.

b. unacceptable system dynamic response:

• an oscillatory response to a contingency that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event.

c. unacceptable equipment tripping:

• tripping of an un-faulted **bulk power system** element (element that has already been classified as **bulk power system**) under planned system configuration due to operation of a protection system in response to a stable power swing,

• the operation of a Type I or Type II **Special Protection System** in response to a condition for which its operation is not required

d. voltage levels in violation of **applicable emergency limits**;

e. loadings on transmission facilities in violation of **applicable emergency limits**.

Special Protection System (SPS) – A protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. Automatic underfrequency load shedding as defined in the NPCC Directory #2 - Emergency Operations - is not considered a SPS. Conventionally switched, locally controlled shunt devices are not **special protection systems**.

Stability - The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or **disturbances**.

Small-Signal Stability - The ability of the electric system to withstand small changes or **disturbances** without the loss of synchronism among the synchronous machines in the system.

Transient Stability - The ability of an electric system to maintain synchronism between its parts when subjected to a **disturbance**, and to regain a state of equilibrium following that **disturbance**.

Appendix B - Guidelines and Procedures for NPCC Area Transmission Reviews

1.0 Introduction

NPCC has established a Reliability Assessment Program to bring together work done by NPCC, Transmission Planners and Planning Coordinators relevant to the assessment of **bulk power system reliability**. As part of the Reliability Assessment Program, the Task Force on System Studies (TFSS) is charged on an ongoing basis with conducting periodic reviews of the **reliability** of the planned bulk power transmission system of each Planning Coordinator Area of NPCC and the transmission interconnections to other Planning Coordinator Areas. The purpose of these reviews is to determine whether each Planning Coordinator Area's planned bulk power transmission system is in conformance with the NPCC *Design and Operation of the Bulk Power System* (Directory #1). Since it is the intention of the NPCC that the *Basic Criteria* in Directory #1 be consistent with the NERC *Standards*, conformance with the NPCC *Basic Criteria* in Directory #1 assures consistency with the NERC *Standards*.

To assist the TFSS in carrying out this charge, each NPCC Planning Coordinator shall conduct an annual assessment of the **reliability** of the planned bulk power transmission system within the Planning Coordinator Area and the transmission interconnections to other Planning Coordinator Areas (an Area Transmission Review), in accordance with these Guidelines, and present a report of this assessment to the TFSS for review. Each Planning Coordinator is also responsible for providing an annual report to the Compliance Committee in regard to its Area Transmission Review in accordance with the *NPCC Reliability Compliance and Enforcement Program* (Document A-8).

The NPCC role in monitoring conformance with the NPCC *Basic Criteria* in Directory #1 is limited to those instances where non-conformance could result in adverse consequences to more than one Planning Coordinator Area. If in the process of conducting the **reliability** review; problems of an intra-Reliability Coordinator Area nature are identified, NPCC shall inform the affected systems and the Planning Coordinator within which the systems are located, but follow-up concerning resolution of the problem shall be the Planning Coordinators responsibility and not that of NPCC. The affected Planning Coordinator will notify NPCC on a timely basis as to the resolution of the identified problem. If the problem is of an inter-Reliability Coordinator Area nature, NPCC shall inform the affected Planning Coordinators and, further, shall take an active role in following-up resolution of the identified problem.

2.0 Purpose of Area Review Presentation

The purpose of the presentation associated with an Area Transmission Review is to demonstrate that the Planning Coordinators planned transmission system, based on its projection of available **resources**, is in conformance with the NPCC *Basic Criteria* in Directory #1. By such a presentation, the Task Force will satisfy itself that the criteria have been met and, in general, that the **reliability** of the NPCC Interconnected Systems will be maintained. Analysis of this material should include a review of **Special Protection Systems**, as well as an assessment of the potential for widespread cascading due to overloads, instability or voltage collapse. In addition, the potential consequences of failure or misoperation of Dynamic Control Systems (DCS), which include Transmission Control Devices as defined in the NERC *Standards*, should be addressed.

This review by the TFSS does not alter Planning Coordinators and/or Company responsibilities with respect to their system's conformity with the NPCC *Basic Criteria* in Directory #1.

3.0 The Study Year to be considered

It is suggested that a study year of 4 to 6 years from the reporting date is a realistic one, both from the viewpoint of minimum lead times required for construction, and the ability to alter plans or facilities. The reviews may be conducted for a longer term beyond 6 years to address identified marginal conditions that may have longer lead-time solutions

4.0 Types and Frequency of Reviews

Each Planning Coordinator is required to present an annual transmission review to TFSS. However, the review presented by the Planning Coordinator may be one of three types: a Comprehensive (or Full) Review, an Intermediate (or Partial) Review, or an Interim Review.

A Comprehensive Review is a thorough assessment of the Planning Coordinator’s entire bulk power transmission system, and includes sufficient analyses to fully address all aspects of an Area Transmission Review as described in Section 5.0. A Comprehensive Review is required of each Planning Coordinator at least every five years. TFSS may require a Planning Coordinator to present a Comprehensive Review in less than five years if changes in the Planning Coordinator’s planned facilities or forecasted system conditions (system changes) warrant it.

In the years between Comprehensive Reviews, Planning Coordinators may conduct

either an Interim Review, or an Intermediate Review, depending on the extent of the Planning Coordinator's system changes since its last Comprehensive Review. If the system changes are relatively minor, the Planning Coordinator may conduct an Interim Review. In an Interim Review, the Planning Coordinator provides a summary of the changes in planned facilities and forecasted system conditions since its last Comprehensive Review and a brief discussion and assessment of the impact of those changes on the bulk power transmission system. No new analyses are required for an Interim Review.

If the Planning Coordinator's system changes since its last Comprehensive Review are moderate or concentrated in a portion of the Planning Coordinator's system, the Planning Coordinator may conduct an Intermediate Review. An Intermediate Review covers all the elements of a Comprehensive Review, but the analyses may be limited to addressing only those issues considered to be of significance, considering the extent of the system changes. If the system changes are major or pervasive, the Planning Coordinator should conduct a Comprehensive Review.

In March of each year, each Planning Coordinator shall present to the TFSS a proposal for the type of review to be conducted that year. TFSS will consider each Planning Coordinator's proposal and either indicate their concurrence, or require the Planning Coordinator to conduct a more extensive review if the Task Force feels that such is warranted based on the Planning Coordinator's system changes since its last Comprehensive Review. Area Interim Review reports shall be presented to TFSS by the end of that calendar year, and Area Intermediate and Comprehensive Review reports shall be presented to TFSS by April of the following year.

5.0 Format of Presentation – Comprehensive and Intermediate Review

Introduction

- Reference the most recent Area Comprehensive Review and any subsequent Intermediate or Interim reviews as appropriate.
- Describe the type and scope of this review.
- For a Comprehensive Review, describe the existing and planned **bulk power system** facilities included in this review.
- Describe changes in system facilities, schedules and **loads** since the most recent Comprehensive Review.
- Include maps and one-line diagrams of the system showing proposed changes as necessary.
- Describe the selected demand levels over the range of forecast system demands.

- Discuss projected firm transfers and interchange schedules.

Study results demonstrating conformance with Section 5.4 of NPCC Directory #1, *Design and Operation of the Bulk Power System* entitled, "Transmission Design Criteria", which includes evaluation of contingencies after any critical generator, transmission circuit, transformer, series or shunt compensating device or HVDC pole has already been lost.

a) Discuss the scope of the analyses. The analyses conducted for a Comprehensive Review should be thorough, but an Intermediate Review may focus on specific areas of the system, specific system conditions, or a more limited set of "critical" **contingencies**.

b) Steady State Assessment

- Discuss the **load** model, power factor, demand side management, and other modeling assumptions used in the analysis. Discuss the methodology used in voltage assessments. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)

- Provide supporting information on the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe results.

- Include plots of "base case" **load** flows with all lines in service for the various conditions studied, e.g., peak, off-peak, and heavy transfers.

- Discuss the **load** flows showing the effects of major planned changes on the system.

- Discuss applicable transfer limits between contiguous areas.

- Discuss the adequacy of voltage performance and voltage control capability for the planned bulk power transmission system.

- Include in the study the planned (including maintenance) outage of any bulk electric equipment (including **protection** systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

c) Stability Assessment

Discuss and/or refer to significant studies showing the effect on the system of **contingencies** as specified in Section 5.4.1 of NPCC Directory #1, *Design and Operation of the Bulk Power System*, entitled "Stability Assessment" and report on the most severe **contingencies** in the following manner:

- Provide supporting information on the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe results.

- Nature of fault, **elements** switched, switching times.

- Plots of angles versus time for significant machines, HVdc and SVC response, voltages at significant buses and significant interface flows.

- Include the effects of existing and planned **protection systems**, including any backup or redundant systems.

- Include the effects of existing and planned control devices.

- Include in the study the planned (including maintenance) outage of any bulk electric equipment (including **protection systems** or their components) at those demand levels for which planned (including maintenance) outages are performed.

For a Comprehensive or Intermediate Review, discuss the **load** model and other modeling assumptions used in the analysis. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)

d) Fault Current Assessment

- Discuss the methodology and assumptions used in the fault current assessment. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)

- Discuss instances where fault levels exceed equipment capabilities and measures to mitigate such occurrences.

- Discuss changes to fault levels at stations adjacent to other Planning Coordinator Areas.

Extreme Contingency Assessment

a) Discuss the scope of the analyses. The analyses conducted for a Comprehensive Review should be thorough, but an Intermediate Review may focus on specific areas of the system, specific system conditions, or a more limited set of "critical" **contingencies**.

b) Provide supporting information on the extreme **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe results.

c) Discuss and/or refer to significant **load** flow studies showing the base case and the post fault conditions for the **contingencies** as specified in Section 5.6 of Directory #1 entitled "Extreme Contingency Assessment". Report on the most severe **contingencies** tested.

d) Discuss and/or refer to significant **stability** studies showing the effect on the system of **contingencies** as specified in Section 5.6 of Directory #1. Report on the most severe **contingencies** tested.

e) In the case where **contingency** assessment concludes serious consequences, conduct an evaluation of implementing a change to address such **contingencies**.

Extreme System Condition Assessment

a) Discuss the scope of the analyses.

b) Discuss and/or refer to significant **load** flow studies showing the effect on the steady state performance of extreme system conditions as specified in Section 5.7 of Directory #1, entitled "Extreme System Condition Assessment". Report on the most severe system conditions and **contingencies** tested.

c) Provide supporting information on the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe results.

d) Discuss and/or refer to significant **stability** studies showing the effect on the dynamic performance of extreme system conditions as specified in Section 5.7 of Directory #1. Report on the most severe system conditions and **contingencies** tested.

e) In the case where extreme condition assessment concludes serious consequences, conduct an evaluation of implementing measures to mitigate such consequences.

Review of Special Protection Systems (SPSs)

a) Discuss the scope of review. A Comprehensive Review should review all the existing, new, and modified **SPSs** included in its transmission plan. An Intermediate Review may focus on the new and modified **SPSs**, and just those existing **SPSs** that may have been impacted by system changes since they were last reviewed.

b) For those **SPSs** whose failure or misoperation has an inter-Planning Coordinator Area or interregional effect, discuss and/or refer to appropriate **load** flow and **stability** studies analyzing the consequences.

c) For those **SPSs** whose failure or misoperation has only local or inter-company consequences, discuss and/or refer to **load** flow and **stability** studies demonstrating that this is still the case for the time period being reviewed.

d) For instances where a **SPS** which was formerly considered to have only local consequences is identified as having the potential for inter-Planning Coordinator Area effects, for the time period being reviewed, the TFSS should notify the Task Forces on Coordination of Planning, System Protection and Coordination of Operation. In such instances a complete review of the **SPS** should be made, as per the *Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems (SPS)* in Directory #7.

Review of Dynamic Control Systems (DCSs)

For those DCSs whose failure or misoperation may have an inter-Planning Coordinator Area or interregional effect, discuss and/or refer to appropriate **stability** studies analyzing the consequences of such failure or misoperation in accordance with the Joint Working Group (JWG)-1 report, "Technical Considerations and Suggested Methodology for the Performance Evaluation of Dynamic Control Systems". A Comprehensive Review should address all potentially impactive existing and new DCSs, but an Intermediate Review may focus on new DCSs and just those existing DCSs that may have been impacted by system changes since they were last reviewed.

Review of Exclusions to the *Basic Criteria*.

Review any exclusions granted under the NPCC *Guidelines for Requesting Exclusions to Sections 5.4.1(b) and 5.5.1(b) Directory #1 Design and Operation of the Bulk Power System* (Appendix E). A Comprehensive Review should address all exclusions, but an Intermediate Review may focus

on just those exclusions that may have been impacted by system changes since they were last reviewed.

Overview Summary of System Performance for Year Studied

6.0 Format of Presentation - Interim Review

Introduction of Interim Review

Reference the most recent Comprehensive Review and any subsequent Intermediate or Interim Reviews as appropriate.

Changes in Facilities (Existing and Planned) and Forecasted System Conditions Since the Last Comprehensive Review.

a) **Load** Forecast

b) Generation **Resources**

c) Transmission Facilities

d) **Special Protection Systems**

e) Dynamic Control Systems

f) Exclusions

Brief Impact Assessment and Overview Summary

The Planning Coordinator will provide a brief assessment of the impact of these changes on the **reliability** of the interconnected **bulk power system**, based on engineering judgment and internal and joint system studies as appropriate.

7.0 Documentation

The documentation required for a Comprehensive or Intermediate Review should be in the form of a report addressing each of the **elements** of the above presentation format. The report should be accompanied by the Planning Coordinator'**s bulk power system** map and one-line diagram, summary tables, figures, and appendices, as appropriate. The report may include references to other studies performed by the Planning Coordinator or by utilities within the Planning Coordinator Area that are relevant to the Area review, with appropriate excerpts from those studies.

The documentation required for an Interim Review should be in the form of a

summary report (normally not exceeding 5 pages), containing a description of system changes and a brief assessment on their impact on the **reliability** of the interconnected **bulk power system**.

8.0 Task Force Follow-Up Procedures

8.1 Once a Planning Coordinator has presented its Review report to the TFSS, TFSS will review the Planning Coordinator's report and any supporting documentation and:

a. Consider whether to accept the report as complete and in full conformance with these Guidelines. If the report is found to be unacceptable, TFSS will indicate to the Planning Coordinator the specific areas of deficiency, and request the Planning Coordinator to address those deficiencies.

b. Consider their concurrence with the results and conclusion(s) of the Planning Coordinator's Review. If there is not concurrence, TFSS will indicate to the Planning Coordinator the specific areas of disagreement, and work with the Planning Coordinator to try to achieve concurrence. If agreement has not been reached within a reasonable period of time, TFSS shall prepare a summary of the results of its review, including a discussion of the Planning Coordinators of disagreement.

8.2 If the results of the Area Review indicates that the Planning Coordinator's planned bulk power transmission system is not in conformance with NPCC Directory #1, TFSS will request the Planning Coordinator to develop a plan to achieve conformance with the Criteria.

8.3 If the Area Review indicates an overall **bulk power system** reliability concern (not specific to the Planning Coordinator's planned bulk power transmission system), TFSS will consider what additional studies may be necessary to address the concern, and prepare a summary discussion and recommendation to the Task Force on Coordination of Planning.

8.4 Upon completion of an Area Review, TFSS will report the results of the review to the Task Force on Coordination of Planning and to the Reliability Coordinating Committee.

Appendix C - Procedure for Testing and Analysis of Extreme Contingencies

1.0 Introduction

Extreme **Contingencies** (ECs) are tested "as a measure of system strength", in order to identify potential patterns of weakness in the bulk power transmission system. This procedure for the testing and analysis of ECs should be used when testing ECs for NPCC studies or studies submitted for NPCC review.

This procedure applies to **reliability** studies that consider the overall performance of the interconnected systems of the NPCC Planning Coordinator Areas. It principally applies to NPCC - wide studies of the **bulk power system**, and generally does not apply to studies normally conducted by NPCC Planning Coordinators that concentrate on individual or a limited number of facilities. This procedure applies to NPCC Overall and Area Transmission Reviews, and may be applicable to other **reliability** studies conducted by the Planning Coordinators, and even to individual facility investigations, where such studies and investigations consider the overall performance of the interconnected systems of the NPCC Planning Coordinator Areas. Certain Transmission Planners or Planning Coordinators may elect to completely mitigate the effects of specific ECs.

Finally, this procedure should be followed in multi-regional **reliability** studies in which NPCC is an active participant, to the extent that this is possible within the framework of such multi-regional efforts.

2.0 Choosing Contingencies for Testing

The ECs are defined in the NPCC Directory #1- Design and Operation of the **Bulk Power System**, and in the NERC Standards. Testing should focus on those ECs expected to have the greatest potential effect on the interconnected system. Particular attention should be paid to contingencies which would result in major angular power shifts, e.g., interruption of shorter transmission paths carrying heavy power flows, leaving longer transmission paths as the only remaining paths. Additionally, contingencies which would result in reversal of major power transfers, e.g., loss of major ties in a neighboring region or Area when said region or Area was transferring power away from the area of interest, should be considered for their impact in subjecting the system to severe power swings (reference EC type “f”). In considering specific **contingencies** to be investigated in an NPCC **reliability** study, all relevant testing done at the Planning Coordinator level should first be reviewed.

In general, a **contingency** in a particular Planning Coordinator Area should be studied, if requested by any other Planning Coordinator, based on a reasonable surmise that the requesting Planning Coordinator may be adversely affected.

3.0 Modeling Assumptions

The assumed generation dispatch is a major consideration in all EC testing. In general, EC testing should use a dispatch pattern considered to be highly probable for the year and **load** level being studied. Intra-Reliability Coordinator Area inter-Reliability Coordinator Area and, where appropriate, inter-regional transfers should be simulated at a level which is experienced or expected at least 75% of the time on a flow duration basis, up to the maximum operating limit for the interfaces being tested. It is not the NPCC intent to test the worst imaginable extreme, but EC tests should be severe.

Each Planning Coordinator shall specify the appropriate Planning Coordinator **load** representation (e.g. active and reactive power as a function of voltage) for use in NPCC **reliability** studies. This applies to long term stability tests or post-transient loadflows as well as **transient stability** tests.

4.0 Evaluating Individual Test Results

A question in evaluating the results of a particular test run is - “Does the system "pass" or "fail" for this **contingency**?” While in the final analysis this is a matter of informed engineering judgment, factors which should be considered include:

1. Lines or transformers loaded above **short time emergency ratings**,

2. Buses with voltage levels in violation of **applicable emergency limits**, (which vary depending on the location within the system),

3. Magnitude and geographic distribution of such overloads and voltage violations across the system,

4. Transient generator angles, frequencies, voltages and power,

5. Operation of Dynamic Control Systems and **Special Protection Systems** (SPS),

6. Oscillations that could cause generators to lose synchronism or lead to dynamic instability,

7. net loss of source resulting from any combination of loss of synchronism of one or more units, generation rejection or runback initiated by SPS, or any other defined system separation,

8. Identification of the extent of the Planning Coordinator Area (s) involved for any indicated instability or islanding (the involvement of more than one

Planning Coordinator Area, should be a major consideration),

9. **Relay** operations or the proximity of apparent impedance trajectories to **relay** trip characteristics,

10. The angle across opened breakers,

11. Adequacy of computer simulation models and data.

Finally, a judgment should be attempted as to whether a "failure" is symptomatic of a basic system weakness, or just sensitivity to a particular EC. For example, should failures turn up for several EC tests in a particular part of the system, it is likely that a basic system weakness has been identified.

The loss of portions of the system should not necessarily be considered a failed result, provided that these losses do not jeopardize the integrity of the overall **bulk power system**.

NPCC study groups should avoid characterizations like "successful" and "unsuccessful" when commenting on individual runs. Rather, the specific initial conditions directly causing or related to the failure, the complete description of the nature of the failure (e.g., voltage collapse, instability, system separation, as well as the facilities involved), and the extent of potential impact on other Planning Coordinator Areas should be reported.

5.0 Evaluating the Results of a Program of EC Testing

The NPCC Directory #1 document - "*Design and Operation of **Bulk Power System***", calls for testing of Extreme **Contingencies** (EC) "as a measure of system strength." The results of all NPCC **reliability** studies are made available to the Planning Coordinators as a guide for planners and designers in the conduct of their future work. The focus of NPCC reports, then, should be on indicating those portions of the system in which basic system weaknesses may be developing, rather than on the results of one specific **contingency**.

Any patterns of weaknesses should be identified, which may include reference to earlier NPCC **reliability** studies and/or Planning Coordinator or member system investigations. There is also a need to distinguish between a "failed" test which indicates sensitivity only to a particular **contingency** run and a "failed" test which indicates a more general system weakness (always keeping in mind the severity of possible consequences of the **contingency**). Actions taken by member systems or Planning Coordinators to reduce the probability of occurrence or mitigate the consequences of the **contingency** should also be cited.

NPCC follow-up, after publication of a final report, is appropriate only for instances

of possible general system weakness. In these instances, the results should be specifically referred to the affected Planning Coordinator or Planning Coordinators for further and more detailed investigation with subsequent reporting to NPCC.

Appendix D - Guidelines for Area Review of Resource Adequacy

1.0 Introduction

NPCC has established a Reliability Assessment Program to bring together work done by the NPCC and Planning Coordinators relevant to the assessment of **bulk power system reliability**. As part of the Reliability Assessment Program, each Planning Coordinator submits to the Task Force on Coordination of Planning its resource adequacy assessment consistent with these guidelines. The Task Force is charged, on an ongoing basis, with reviewing and recommending NPCC Reliability Coordinating Committee approval of these reviews of **resource** adequacy of each Planning Coordinator Area of NPCC.

Resources refer to the total contributions provided by supply-side and demand-side facilities and actions. Supply-side facilities include all generation sources within a Planning Coordinator Area and firm capacity backed purchases from neighboring systems. Demand-side facilities include measures for reducing or shifting **load**, such as conservation, **load** management, interruptible **loads**, dispatchable **loads** and small identified generation which is not metered at the control centers.

The NPCC role in monitoring conformance with the NPCC Directory #1 - *Design and Operation of Bulk Power System* is essential because under this criterion, each Planning Coordinator determines its resource requirements by considering interconnection assistance from other Planning Coordinators, on the basis that adequate **resources** will be available in those Planning Coordinator Areas. Because of this reliance on interconnection assistance, inadequate **resources** in one Planning Coordinator Area could result in adverse consequences in another Planning Coordinator Area.

It is recognized that all Planning Coordinators may not necessarily express their own **resource** adequacy criterion as stated in the NPCC Basic Criteria in Directory #1. However, the NPCC Basic Criteria provides a reference point against which a Planning Coordinator's **resource** adequacy criterion can be compared.

The NPCC will not duplicate reviews and studies completed by member systems and Planning Coordinators**.** The NPCC may reference these reviews in appropriate NPCC reports.

2.0 Purpose of Presentation

The purpose of the presentation associated with a **resource** adequacy review is to show that each Planning Coordinator's proposed **resources** are in accordance with the NPCC Directory #1 - *Design and Operation of the Bulk Power System.*
By such a presentation, the Task Force will satisfy itself that the proposed **resources** of each NPCC Planning Coordinator will meet the NPCC Resource Adequacy -

Design Criteria, as defined NPCC Directory #1, over the time period under consideration. The review by the Task Force on Coordination of Planning does not replace Planning Coordinator and/or company responsibility to assess their systems in conformity with the NPCC Basic Criteria in Directory #1.

3.0 Time Period to be Considered

The time period to be considered for a Planning Coordinator's Comprehensive **Resource** Review will be five years and be undertaken every three years. In subsequent years, the Planning Coordinator shall conduct Annual Interim Reviews that will cover, at a minimum, the remaining years studied in the Comprehensive Review. Based on the results of the Annual Interim Review, the Task Force may recommend that the Planning Coordinator conduct the next Comprehensive Review at a date earlier than specified above. Comprehensive and Interim reviews are normally expected to be presented to the Task Force before the beginning of the first time period covered by the assessment.

4.0 Format of Presentation and Report – Comprehensive Review

Each Planning Coordinator should include in its presentations and in the accompanying report documentation, as a minimum, the information listed below. At its own discretion, the Planning Coordinator may discuss other related issues not covered specifically by these guidelines.

4.1 Executive Summary

4.1.1 Briefly illustrate the major findings of the review.

4.1.2 Provide a table format summary of major assumptions and results.

4.2 Table of Contents

4.2.1 Include listing of all tables and figures.

4.3 Introduction

4.3.1 Reference the previous NPCC Area Review.

4.3.2 Compare the proposed **resources** and **load** forecast covered in this NPCC review with that covered in the previous review

4.4 Resource Adequacy Criterion

4.4.1 State the Planning Coordinator's **resource** adequacy criterion.

4.4.2 State how the Planning Coordinator criterion is applied; e.g., **load** relief steps.

4.4.3 Summarize **resource** requirements to meet the criteria for the time period under consideration. If interconnections to other Planning Coordinators and regions are considered in determining this requirement, indicate the value of the interconnections in terms of megawatts.

4.4.4 If the Planning Coordinator criterion is different from the NPCC criterion, provide either an estimate of the **resources** required to meet the NPCC criteria or a statement as to the comparison of the two criteria.

4.4.5 Discuss **resource** adequacy studies conducted since the previous Area Review, as appropriate.

4.5 Resource Adequacy Assessment

4.5.1 Evaluate proposed **resources** versus the requirement to reliably meet projected electricity demand assuming the Planning Coordinator's most likely **load** forecast.

4.5.2 Evaluate proposed **resources** versus the requirement to reliably meet projected electricity demand assuming the Planning Coordinator’s high **load** growth scenario.

4.5.3 Discuss the impact of **load** and **resource** uncertainties on projected Planning Coordinator Area **reliability** and discuss any available mechanisms to mitigate potential **reliability** impacts.

4.5.4 Review the impacts that major proposed changes to market rules may have on Planning Coordinator Area **reliability**.

4.6 Proposed Resource Capacity Mix

4.6.1 Discuss any **reliability** impacts resulting from the proposed **resources** fuel supply and transportation or environmental considerations.

4.6.2 Describe available mechanisms to mitigate any potential **reliability** impacts of **resource** fuel supply, demand resource response, transportation issues and/or environmental considerations.

4.6.3 Discuss any **reliability** impacts related to an **Area**'s compliance with state, Federal or Provincial requirements (such as environmental, renewable energy, or greenhouse gas reductions).

5.0 Format of Presentation and Report – Annual Interim Review

The Annual Interim Review should include a reference to the most recent Comprehensive Review; a listing of major changes in: facilities and system conditions, **load** forecast, generation resources availability; related fuel supply and transportation information, environmental considerations, demand response programs, transfer capability and **emergency** operating procedures. In addition, the assessment should also include a comparison of major changes in market rules, implementation of new rules, locational requirements, and installed capacity requirements. Finally, the report should include a brief impact assessment and an overall summary.

The Planning Coordinator will provide a brief assessment of the impact of these changes on the **reliability** of the interconnected **bulk power system**. This assessment should be based on engineering judgment, internal system studies and appropriate joint interconnected studies. To the extent that engineering judgment or existing studies can be used to clearly demonstrate that a Planning Coordinator Area is expected to meet the NPCC resource adequacy criterion, detailed system LOLE studies are not required.

The documentation for the Annual Interim Review should be in the form of a summary report (normally not exceeding three to five pages.)

Sections A and B should describe the **reliability** model and program used for the **resource** adequacy studies discussed in Section 4.5. Section C should describe the Task Force follow-up procedures.

A. <u>Description of Resource Reliability Model</u>

1.1 Load Model

1.1.1 Description of the **load** model and basis of period **load** shapes.

1.1.2 How **load** forecast uncertainty is handled in model.

1.1.3 How the electricity demand and energy projections of interconnected entities within the Planning Coordinator Area that are not members of the Planning Coordinator Area are addressed.

1.1.4 How the effects (demand and energy) of demand-side management programs (e.g., conversion, interruptible demand, direct control **load** management, demand (**load**) response programs) are addressed.

1.2 Supply Side **Resource** Representation

1.2.1 Resource Ratings

1.2.1.1 Definitions.

1.2.1.2 Procedure for verifying **ratings**. Reference NPCC Document B-9, *Guide for Rating Generating Capability*.

1.2.2 Unavailability Factors Represented

1.2.2.1 Type of unavailability factors represented; e.g., forced outages, planned outages, partial derating, etc.

1.2.2.2 Source of each type of factor represented and whether generic or individual unit history provides basis for existing and new units.

1.2.2.3 Maturity considerations, including any possible allowance for in-service date uncertainty.

1.2.2.4 Tabulation of typical unavailability factors.

1.2.3 Purchase and Sale Representation.

1.2.3.1. Describe characteristics and level of dependability of transactions.

1.2.4 Retirements.

1.2.4.1 Summarize proposed retirements.

1.3 Representation of Interconnected System in Multi-Area **Reliability** Analysis, including which Planning Coordinator Areas and regions are considered, interconnection capacities assumed, and how expansion plans of other Planning Coordinators and regions are considered.

1.4 Modeling of Variable and Limited Energy Sources.

1.5 Modeling of Demand Side Resources and Demand (**Load**) Response Programs.

1.5.1 Description should include how such factors as in-service date uncertainty, **rating**, availability, performance and duration are addressed.

1.6 Modeling of all **Resources**.

1.6.1 Description should include how such factors as in-service date uncertainty; capacity value, availability, **emergency** assistance, scheduling and deliverability are addressed.

1.7 Other assumptions i.e., internal transmission limitations, maintenance over-runs, fuel supply and transportation and environmental constraints.

1.8 Incorporate the **reliability** impacts of market rules.

B. Other Factors, If Any, Considered in Establishing Reserve Requirement Documentation

The documentation required to meet the requirements of the above format should be in the form of summaries of studies performed within a Planning Coordinator Area, including references to applicable reports, summaries of reports or submissions made to regulatory agencies.

C. Task Force Follow-Up Procedures

Once a specific Planning Coordinator has made a presentation or a series of presentations to the Task Force on Coordination of Planning, the latter shall:

1. Prepare a brief summary of key issues discussed during the presentation.

2. Note where further information was requested and the results of such further interrogations.

3. Note the specific items that require additional study and indicate the responsibilities for undertaking these studies.

4. Recommend approval to the Reliability Coordinating Committee.

Appendix E - Guidelines for Requesting Exclusions to Sections 5.4.1 (B) and 5.5.1 (B) of NPCC Directory #1 – *Design and Operation of the Bulk Power System*

1.0 Introduction

The Northeast Power Coordinating Council (NPCC) was formed to promote the **reliability** and efficiency of electric service of the interconnected **bulk power system** of the members of the NPCC by extending the coordination of their system design and operations as cited in the NPCC Memorandum of Agreement. Towards that end, the Member Systems of NPCC adopted the *Basic Criteria for Design and Operation of Interconnected Power Systems* (Directory #1 – *Design and Operation of the Bulk Power System*), which establishes the minimum standards for design and operation of the interconnected **bulk power system** of NPCC. In accordance with those standards, the **bulk power system** should be designed and operated so as to withstand certain specific **contingencies**.

One such **contingency**, listed under Section 5.4.1(b), Transmission Design Criteria - **Stability** Assessment, and under Section 5.5.1(b), Transmission Operating Criteria - Normal Transfers, involves "simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with normal **fault clearing**." Although this **contingency** is normally included in the NPCC Criteria, the Basic Criteria in Directory #1 define specific conditions for which a multiple circuit tower situation is an acceptable risk and, therefore, can be excluded.

Directory #1 also allows for requests for exclusion from this **contingency**, on the basis of acceptable risk, for other instances of multi-circuit tower construction. All exclusions must be approved by the Reliability Coordinating Committee (RCC). An acceptance of a request for exclusion is dependent on the successful demonstration that such exclusion is an acceptable risk. These guidelines describe the procedure to be followed and the supporting documentation required when requesting exclusion, and establishes a procedure for periodic review of exclusions of record.

2.0 Documentation

The documentation supporting a request for exclusion to Sections 5.4.1(b) and 5.5.1(b) of the Basic Criteria must include the following:

2.1 A description of the facilities involved, including geographic location, length and type of construction, and electrical connections to the rest of the interconnected power system;

2.2 Relevant design information pertinent to the assessment of acceptable risk, which might include: details of the construction of the facilities, geographic or

atmospheric conditions, or any other factors that influence the risk of sustaining a multi-circuit **contingency**;

2.3 An assessment of the consequences of the occurrence of a multi-circuit **contingency**, including, but not limited to, a discussion of levels of exposure and probability of occurrence of **significant adverse impact** outside the local area;

2.4 For existing facilities, the historical outage performance, including cause, for multi-circuit **contingencies** on the specific facility (facilities) involved as compared to that of other multi-circuit tower facilities;

2.5 For planned facilities, the estimated frequency of multi-circuit **contingencies** based on the historical performance of facilities of similar construction located in an area with similar geographic climate and topography.

3.0 Procedure for obtaining an Exclusion

The following procedure shall be used in obtaining exclusion to Sections 5.4.1(b) or 5.5.1(b) of Directory #1:

3.1 The entity requesting the exclusion (the Requestor) shall submit the request and supporting documentation to the Task Force on System Studies (TFSS) after acceptance has been granted by the Requestor's own Planning Coordinator, if such process is applicable.

3.2 TFSS shall review the request, verify that the documentation requirements have been met, and determine the acceptability of the request.

3.3 If TFSS deems the request acceptable, TFSS shall request the Task Force on Coordination of Planning (TFCP), the Task Force on Coordination of Operation (TFCO), and the Task Force on System Protection (TFSP) to review the request. The Requestor shall provide copies of the request and supporting documentation to the other Task Forces as directed by TFSS. If additional information is requested by the other Task Forces as part of their assessment, the Requestor will provide this information directly to the interested Task Force, with a copy to the TFSS. The other Task Forces shall review the request and indicate their acceptance or non-acceptance to TFSS.

3.4 If any of the four Task Forces determines the request is not acceptable, TFSS will respond to the Requestor with the determination and inform the RCC and the other Task Forces of the decision.

3.5 TFSS shall notify TFCP, TFCO, and TFSP of an exclusion that has been accepted by the Task Forces and the basis for the exclusion. The TFSS will then make a recommendation to the RCC regarding the exclusion.

3.6 The NPCC Policy for Alternative Dispute Resolution is available for use if the decision is unacceptable to the Requestor.

Upon acceptance of the requested exclusion by the RCC, TFSS shall so notify the Requestor and update a summary list of the exclusions. The summary list and supporting documents shall be maintained by NPCC.

4.0 Periodic Review of Exclusions of Record

Exclusions shall be reviewed within the Planning Coordinator's transmission reviews as provided in *Guidelines for NPCC Area Transmission Reviews* (NPCC Directory #1 – Appendix C). This review shall verify that the basis for each exclusion is still valid. TFSS shall notify TFCP, TFCO, TFSP, and the RCC when a Planning Coordinator's transmission review has determined exclusion is no longer applicable, and revise the exclusion summary list accordingly.

Appendix F – Procedure for Operational Planning Coordination

1.0 Introduction

The Reliability Coordinators (RC) of the Northeast Power Coordinating Council, Inc. (NPCC) require access to the security data specified in this procedure in order to adequately assess the reliability of the NPCC bulk power system. All users of the electric systems, including market participants, must supply such data to the NPCC Reliability Coordinators. Coordination among and within the Reliability Coordinator Areas (RC Area) of NPCC is essential to the reliability of interconnected operations. Timely information concerning system conditions should be transmitted by the NPCC RC Areas to other RC Areas as needed to assure reliable operation of the **bulk power system**. One aspect of this coordination is to ensure that adjacent RC Areas and neighboring systems are advised on a regular basis of expected operating conditions, including generator, transmission and **system protection**, including Type I **special protection system,** outages that may materially reduce the ability of an RC Area to contribute to the reliable operation of the interconnected system, or to receive and/or render assistance to another RC Area. To the extent practical, the coordination of outage schedules is desirable in order to limit the severity of such impacts.

To ensure that there is effective coordination for system **reliability** concerns, this document establishes procedures for the exchange of information regarding load/capacity forecasts, including firm sales and firm purchases, generator outage schedules, and transmission outage schedules for those facilities that may have an adverse impact on other RC Area(s). It also details general action that may be taken to improve the communication of problems as well as specific topics that may be discussed in regularly scheduled, pre-arranged conference call meetings or in conference calls arranged in anticipation of problems such as capacity deficiency or inadequate light load margin in one or more RC Areas.

Participants and other recipients of the information provided by this process must adhere to the NERC *Confidentiality Agreement for Electric System Operating Reliability Data*.

2.0 Load/Capacity Forecasts

2.1 Twice yearly, by May 15th and November 15th respectively, the Operations Planning Working Group (CO 12) will perform a summer and winter assessment for the next season. The methodology and format of the seasonal report will be presented in NPCC Document C-45, "CO-12 Seasonal Assessment Methodology," currently under development.

The results will be reviewed by the NPCC Task Force on Coordination of Operation (TFCO) and the NPCC Reliability Coordinating Committee (RCC) in advance of the spring and autumn meetings of both groups.

2.2 Each week, each RC Area will review its weekly net resource capacity margin, as defined in Attachment A, for the twelve weeks to follow and forward the information to the NPCC Staff for distribution to all NPCC RC Areas. If an NPCC RC Area identifies a deficiency or light load condition, the RC Area should identify the cause(s) and mitigation measures that have been implemented, or will be implemented, to manage the issue.

3.0 Generator Outage Coordination

3.1 Each RC Area should exchange current and expected critical generation outages.

4.0 Transmission Outage Coordination

4.1 Advance Planning of Transmission Facility Outages

NPCC Document Directory#1, *Basic Criteria for Design and Operation of Interconnected Power Systems,* requires that scheduled outages of transmission facilities that affect **reliability** between RC Areas be coordinated sufficiently in advance of the outage to permit the affected RC Area to maintain **reliability**. For the purposes of this procedure, each RC should exchange critical transmission outages as identified in coordination agreements with their interconnected neighbors and jointly develop and maintain a Facilities Notification List.

4.2 Facilities Notification List

The NPCC Facilities Notification List, Attachment D, has two components:

1) the NPCC Transmission Facilities Notification List; and
2) the list of NPCC Type I **special protection systems**.

The Facilities Notification List is developed by each RC Area and specifies all facilities that, if removed from service, may have a significant, direct or indirect impact on another RC Area's transfer capability. The cause of such impact might include stability, voltage, and/or thermal considerations.

Prior to October 1st of each year, each RC Area will review and update its Facilities Notification List and coordinate necessary changes with other appropriate NPCC RC Areas. Prior to January 1st, and after review by the TFCO, the approved, updated Facilities Notification List will be posted on the NPCC secure website.

The Task Force on System Protection develops yearly the list of NPCC Type 1 **special protection systems** with input from the Task Force on System Studies.

It should be noted that revisions to the Facilities Notification List only will not follow the NPCC Process for Open Review due to the secure nature of the information contained, and Attachment D is not openly published with this Procedure.

A temporary reconfiguration of the network may result in an outage to one or more facilities not listed in Attachment D having an impact on other NPCC RC Areas. It is the responsibility of the RC experiencing the condition to notify impacted RCs in a timely manner and provide updated status reports during the condition.

4.3 Notifications of Work

4.3.1 Notification requirements should be defined in interconnected coordination agreements. The time frames identified below are the minimum notification requirements.

4.3.2 The initiating RC will advise affected RCs of all applications for outages of facilities on the Facilities Notification List, including those which have been planned.

All outages to equipment listed in the Facilities Notification List should be planned with as much lead time as practical.

Normally, notification for work on facilities covered by this instruction will be submitted to the appropriate RC Areas at least two (2) working days prior to the time the facility is to be taken out of service.

When an RC Area receives an outage notification from another RC Area, prompt attention will be given to the notification and appropriate comments rendered. Analysis will be conducted by each RC Area in accordance with internal procedures.

4.3.3 An RC Area will not normally remove from service any transmission facility, which might have a **reliability** impact on an RC Area without prior notification to and appropriate review by that RC Area. In the event of an **emergency** condition, each RC Area may take action as deemed appropriate. Other RC Areas should be notified immediately.

An RC Area will make every effort to reschedule routine (non-emergency) transmission outages that severely degrade the reliability of an adjacent RC Area or neighboring system.

4.3.4 Each RC Area will advise the other affected RC Areas of any protection outage associated with RC Area tie line facilities. Coordination agreements may identify additional reporting

requirements associated with protection outages.

5.0 Data Providers

NPCC entities are to provide the data in order to adequately assess the reliability of the NPCC bulk power system.

6.0 Specific Communications

Conditions in an RC Area that may have an impact on another RC Area should be communicated in a clear and timely manner. Specific communications are conducted as follows:

6.1 Weekly

Each Thursday a conference call will be initiated by the NPCC Staff to discuss operations expected during the seven-day period starting with the following Sunday. Operations personnel from the NPCC RC Areas will participate. In advance of the conference call, each RC Area will prepare the data specified in Attachments A and B, and forward it to the NPCC Staff a minimum of one hour in advance of the scheduled call. The completed "NPCC Weekly Conference Call Generating Capacity Worksheet," Attachment B, together with the list of "Twelve Weeks Projections of Net Margins," Attachment C, will be forwarded to the conference call participants by the NPCC Staff.

Each RC will review its weekly capacity margins for the next twelve week period. If a deficiency or light load condition is identified, the RC will identify the cause of the deficiency or light load condition and discuss proposed mitigation measures.

The NPCC Staff will prepare Conference Call Notes that will be forwarded to the conference call participants and members of the TFCO by the following Friday afternoon.

If a deficiency or light load condition, or if adverse system operating conditions are expected within the next week, any RC Area may recommend that an Emergency Preparedness Conference Call (NPCC Document C-01) take place at an appropriate time.

Items of particular concern that should be discussed during the weekly conference call are described in Attachment C.

6.2 Emergency Preparedness Conference Call

Whenever adverse system operating or weather conditions are expected, any RC Area may request the NPCC Staff to arrange an Emergency Preparedness Conference Call (NPCC Document C-01) to discuss operating details with appropriate operations management personnel from the NPCC RC Areas and neighboring systems.

6.3 Daily Conference Calls

Each of the NPCC Reliability Coordinator Area control rooms participate in a regularly scheduled daily conference call. The goal of this call is to alert NPCC Reliability Coordinators of any potential emerging problems. Subjects for discussion are limited to credible events which could impact the ability of a Reliability Coordinator to serve its load and meet its operating reserve obligations, or which would impose a burden to the Interconnection.

Procedure for Operational Planning Coordination – Attachment A

Load and Capacity Table Instructions

and

Generating Capacity Worksheet Instructions

Week Beginning	The seven day period for which data is to be reported is defined as starting with the Sunday following the conference call through the following Saturday.
Installed Generating Capacity (Line Item 1)	Include all available generation at its maximum demonstrated capability for the appropriate seasonal capability period.
Firm Purchases (Line Item 2)	Include only those transactions where capacity is delivered. Exclude "energy only" transactions.
Firm Sales (Line Item 3)	Include only those transactions where capacity is delivered. Exclude "energy only" transactions.
Net Capacity (Line Item 4)	Add Installed Generating Capacity and Firm Purchases. Subtract Firm Sales. (Line 1+Line 2-Line3)
Peak Load Forecast (Line Item 5)	The peak load forecast should be the best estimate of the RC Area's maximum peak load exposure anticipated for the week reported.
Available Reserve (Line Item 6)	Subtract Peak Load Forecast from Net Capacity. (Line 4-Line5.)
Demand Side Management (Line Item 7)	Include only maximum capability which can be obtained by operator initialization within four (4) hours.

Attachment A (continued)	
Known Unavailable Capability (Line Item 8)	Include all known outages, as well as those deratings or unit outages presently forced out, unavailable, on extended cold standby or which are anticipated to remain out of service. This would also include capacity unavailable due to transmission constraints.
Net Reserve (Line Item 9)	Available Reserve plus Demand Side Management minus Known Unavailable Capacity. (Line 6+Line 7-Line 8)
Required Operating Reserve (Line Item 10)	The methodology used by each RC Area in calculating operating reserve must, as a minimum, meet the requirements of NPCC Document A-06, "Operating Reserve Criteria." Methodologies differing from the A-06 requirements should be clarified in Attachment B, "NPCC Weekly Conference Call Generating Capacity Worksheet," under the tab for "Operating Reserve."
Gross Margin (Line Item 11)	Subtract Required Operating Reserve from Net Reserve. (Line 9-Line 10)
Unplanned Outages (Line Item 12)	Estimate the amount of generating capacity which will be unavailable. This quantity should be based on historical averages for forced outages and deratings.
Net Resource Capacity Margin (Line Item 13)	Subtract Unplanned Outages from Gross Margin. A positive value reflects surplus reserve. A negative value reflects a deficiency. (Line 11-Line 12)
Forecast High / Low Temperatures and Days (Line Item 14)	Include the expected high and low temperatures for the RC Area for the week, and indicate the day on which they are expected to occur.

Attachment A (continued)	
Seasonal High / Low Temperatures (Line Item 15)	Include the expected high and low forecast seasonal temperatures for the RC Area.
Minimum Load Forecast (Line Item 16)	The minimum load forecast should be the best estimate of the RC Area's minimum load exposure anticipated for the week reported.
Minimum Resources (Line Item 17)	The Minimum Resources are the Reliability Coordinator Area's total expected on-line generator minimum output capability and must-take purchases.
Light Load Margin (Line Item 18)	Subtract Minimum Resources from Minimum Load Forecast. A negative number indicates a light load condition. (Line 16-Line 17)

Procedure for Operational Planning Coordination – Attachment B

NPCC Weekly Conference Call Generating Capacity Worksheet

The "NPCC Weekly Conference Call Generating Capacity Worksheet" is an active Excel spreadsheet used each week to assist in the calculation of the data discussed during the weekly conference call. A blank template, in Microsoft Office Excel 2003, is available from the NPCC office.

Procedure for Operational Planning Coordination - Attachment C

CONDITIONS FOR DISCUSSION

Items of particular concern that should be discussed during a conference call include, but are not limited to, the following:

- anticipated weather;
- largest first and second contingencies;
- operating reserve requirements and expected available operating reserve;
- capacity deficiencies;
- potential fuel shortages or potential supply disruptions which could lead to energy shortfalls;
- light load margins;
- general and specific voltage conditions throughout each system or RC Area;
- status of short term contracts and other scheduled arrangements, including those that impact on operating reserves;
- additional capability available within twelve hours and four hours;
- generator outages that may have a significant impact on an adjacent RC Area or neighboring system;
- transmission outages that might have an adverse impact on internal and external energy transfers;
- potential need for emergency transfers;
- expected transfer limits and limiting elements;
- a change or anticipated change in the normal operating configuration of the system, such as the temporary modification of relay protection schemes so that the usual and customary levels of protection will not be provided, or the arming of special protection systems not normally armed, or the application of abnormal operating procedures; and
- update of the abnormal status of NPCC Type I special protection systems forced out of service.

Attachment D

NPCC Facilities Notification List

Attachment D is not publicly available due to the confidential nature of the information presented.

Appendix G - Procedures for Inter Reliability Coordinator Area Voltage Control

1.0 Introduction

This Procedure provides general principles and guidance for effective inter-Transmission Operator Area voltage control, consistent with the NPCC, Directory #1, "Design and Operation of the Bulk Power System," and applicable NERC Standards. Specific methods to implement this Procedure may vary among Transmission Operators, depending on local requirements. Coordinated inter- Transmission Operator Area voltage control is necessary to regulate voltages to protect equipment from damage and prevent voltage collapse. Coordinated voltage regulation reduces electrical losses on the network and lessens equipment degradation. Local control actions are generally most effective for voltage regulation. Occasions arise when adjacent Transmission Operators can assist each other to compensate for deficiencies or excesses of **reactive power** and improve voltage profiles and system security.

2.0 Principles

Each Transmission Operator develops, and operates in accordance with, its own voltage control procedures and criteria which are consistent with NPCC, Inc. Criteria and NERC Standards. Adjacent Transmission Operators should be familiar with the respective criteria and procedures of their neighboring Transmission Operators should mutually agree upon procedures for inter- Transmission Operator Area voltage control. Whether inter- Transmission Operator Area voltage control is carried out through specific or general procedures, the following should be considered and applied:

2.1 To effectively coordinate voltage control, location and placement of metering for **reactive power** resources and voltage controller status should be consistent between adjacent Transmission Operators.

2.2 the availability of **voltage regulating transformers** in the proximity of **tie lines**;

2.3 voltage levels, limits, and regulation requirements for stations on either side of an inter- Transmission Operator Area interface;

2.4 the circulation of **reactive power** (export at one tie point in exchange for import at another);

2.5 **tie line** reactive losses as a function of real **power** transfer;

2.6 reactive **reserve** of on-line generators;

2.7 shunt reactive device availability and switching strategy; and

2.8 **static VAR compensator** availability, reactive **reserve**, and control strategy.

3.0 Procedure

Transmission Operators maintain normal voltage conditions, in accordance with their own individual or joint operating policies, procedures and applicable interconnection agreements. In the event the system state changes to an abnormal voltage condition, the Transmission Operator in which the abnormal condition is originating should immediately take corrective action. If the corrective control actions are ineffective, or the Transmission Operator has insufficient reactive resources to control the problem, assistance may be requested from other Transmission Operators.

3.1 Normal Voltage Conditions

The **bulk power system** is operating with Normal Voltage Conditions when:

- actual voltages are within applicable normal (pre-**contingency**) voltage ranges; and
- expected post-**contingency** voltages are within applicable post-**contingency** minimum and maximum levels following the most severe **contingency** specified in Directory #1 "Design and Operation of the Bulk Power System."

Each Transmission Operator should maintain a mix of static and dynamic resources, including reactive **reserves**.

3.1.1 Providing that it is feasible to regulate reactive flows on its **tie lines**, each Transmission Operator should establish a mutually agreed upon voltage profile with adjacent Transmission Operators and with other neighboring systems. This voltage profile should conform to the provisions of the relevant interconnection agreements and may provide for:

- The minimum and maximum voltage at stations at or near terminals of inter-Transmission Operator Area tie lines;
- The receipt of reactive flow at one tie point in exchange for delivery at another;
- The sharing of the reactive requirements of **tie lines** and series regulating equipment (either equally or in proportion to line lengths, etc.); and
- The transfer of **reactive power** from one Transmission Operator to another.

This voltage profile, adjusted for changes in operating conditions, should be considered as the basis for determining which Transmission Operator should implement necessary measures to alleviate abnormal voltage conditions affecting more than one Transmission Operator as discussed in 3.2.10 below.

3.1.2 Each Transmission Operator should anticipate voltage trends and initiate corrective action in advance of critical periods of heavy and light **loads**.

4.0 Procedure for Triennial Monitoring and Reporting of Inter-Area Voltage Control

4.1 On, or shortly before, the first of July, the TFCO Secretary will write to each TFCO member, requesting a written response by the end of July in the form of:

a) A copy of any new procedures and principles between the reporting Reliability Coordinator and adjacent Reliability Coordinators providing detailed application, or,

b) a copy of any new understanding, such as the minutes of an operating committee meeting between Reliability Coordinators, indicating that such detailed application is not required, and why;

c) a copy of any revisions to the procedures and principles, or understandings currently on file at NPCC, that exists between the reporting Reliability Coordinator and adjacent Reliability Coordinators;

d) a response indicating no change to existing procedures and principles, or understandings currently on file at NPCC.

4.2 The TFCO Secretary will draft a report summarizing the extent to which responses indicated conformance with the NPCC Procedures, and will forward it to TFCO members at least two weeks prior to the October TFCO meeting.

4.3 Following TFCO review and adoption, the TFCO Chairman will forward the report to the Chairman of the Reliability Coordinating Committee (RCC) recommending acceptance or other action as deemed appropriate. This will normally be forwarded three weeks prior to the next regularly scheduled RCC meeting.

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NPCC
Regional Reliability Reference Directory # 5
Reserve

Task Force on Coordination of Operations Revision Review Record:
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Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	**12/2/2010**		**New**
1	**10/11/2012**	**Revised/clarified Criteria: (radial source cont., time zero)**	**Revisions**

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1.0 Title **Reserve**

1.1 Directory Number 5

1.2 Objective

The purpose of this Directory is to present the requirements with which the applicable entity must plan for and deploy adequate **reserve**. This Directory provides minimum requirements governing the amount, availability, distribution, and activation of **reserve** in addition to those specified in applicable NERC standards.

1.3 Effective Date **December 2, 2010**

1.4 Background

This Directory was developed from the NPCC A-6 Operating Reserve Criteria document. Guidelines and procedures for consideration in the implementation of this Directory are provided in the Appendices. Content from various NPCC B and C documents was used in both the body of this Directory and in the Appendices.

1.5 Applicability

1.5.1 Functional Entities

Balancing Authorities
Reliability Coordinators
Load Serving Entities
Generator Owners

2.0 Terms Defined in this Directory

NPCC-defined terms found in this Directory appear in bold typeface and can be found in the NPCC Glossary.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing requirements that are associated with this Directory include, but may not be limited to:

BAL-001
BAL-002
BAL-003
BAL-005
EOP-002

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Full Member, More Stringent Criteria

In the continuous operation of electric power systems, **operating capacity** is required to meet forecast demand, including an allowance for error, to provide protection against equipment failure which has a reasonably high probability of occurrence, and to provide adequate regulation of frequency and **tie line** power flow. The **operating capacity** in excess of that required for actual load is commonly referred to as **reserve.**

5.1 **Ten-Minute Reserve** Requirements

NPCC **ten-minute reserve** meets the requirement for the contingency reserve within the NERC standards. Each Balancing Authority shall have **ten-minute reserve** available to it that is at least equal to its **first contingency loss. Ten-minute reserve** shall be sustainable as specified in section 5.13.

5.2 Restoration of **Ten-Minute Reserve**

If a Balancing Authority becomes deficient in **ten-minute reserve** or forecasts a deficiency without counting the contribution of either curtailment of interruptible loads that is not part of normal operations, and/or public appeals:

5.2.1 It shall restore its ten-minute reserve as soon as possible and within the duration specified by the appropriate NERC standard.

5.2.2 If 5.2.1 cannot be achieved, minimize the magnitude and duration of **ten-minute reserve** deficiency.

Refer to Appendix 3, Section 3.1 for guidance on the restoration of ten-minute reserve.

If the actions identified in Appendix 3 do not fully restore **ten-minute reserve** within the specified duration, see Directory 2, "Emergency Operations," to determine additional actions required.

5.3 **Thirty-Minute Reserve** Requirements

Each Balancing Authority shall have **thirty-minute reserve** available to it that is at least equal to one-half its **second contingency loss**. **Thirty-minute reserve** shall be sustainable as specified in section 5.13.

5.4 Restoration of **Thirty-Minute Reserve**

If a Balancing Authority is deficient in **thirty-minute reserve** for four hours, or if it forecasts a deficiency of any duration beyond a four hour horizon, refer to Appendix 3, Sections 3.6 and 3.7 for guidance on the restoration of **thirty-minute reserve**.

No further corrective actions are required if the actions in Appendix 3, Sections 3.6 and 3.7, do not restore **thirty-minute reserve**.

5.5 Requirement for **Synchronized Reserve** Available Within Ten Minutes

Requirements for **synchronized reserve** available within ten minutes for NPCC Balancing Authorities shall be based on demonstrated performance. The requirements shall not be more than 100% or less than 25% of the **ten-minute reserve** requirement.

5.5.1 Computing Adjustments to the Requirement of **Synchronized Reserve** Available Within Ten Minutes

The requirement for **synchronized reserve** available within ten minutes shall be adjusted based upon the Balancing Authority's past performance in returning its Area Control Error (ACE) to pre-contingency values, or to zero, within fifteen minutes following loss of resource, in accordance with the following relationship:

- The requirement for **synchronized reserve** available within ten minutes shall be reduced to a minimum of 25 percent of the **ten-minute reserve** requirement in steps of 10 percent of the **ten-minute reserve** requirement for every time a Balancing Authority successfully

returns its ACE to pre-contingency values, or to zero, following successful recoveries for events meeting or exceeding the NPCC reportable event threshold. Successful recoveries that occur in the same month as a failure shall not be counted in that month towards a reduced synchronized reserve requirement. However, successful recoveries subsequent to a failure can be counted in the next month provided there are no failures in that month.

- The requirement for **synchronized reserve** available within ten minutes shall increase by 20 percent of the **ten-minute reserve** requirement for every time a Balancing Authority fails to return its ACE to pre-contingency values or to zero within fifteen minutes when a contingent Balancing Authority experiences a contingency whose size is greater than or equal to the NPCC Reportable Event Threshold but less than the NERC Disturbance Control Standard default reporting threshold of 80% of the **first contingency loss**. The maximum requirement for **synchronized reserve** available within ten minutes shall be 100 percent of the Balancing Authority's **ten-minute reserve** requirement.

- Changes in the requirement for **synchronized reserve** available within ten minutes shall be calculated within twenty days after the end of each month. The new requirement for **synchronized reserve** available within ten minutes is applied on the first calendar day of the new month following the calculation of the new requirement and shall remain in effect for the full month.

5.5.2 Restoration of **Synchronized Reserve** Available Within Ten Minutes

If a Balancing Authority becomes deficient in the NPCC requirement for **synchronized reserve** available within ten minutes, it shall be restored according to the time constraints specified for **ten minute reserve**. If a Balancing Authority becomes deficient in meeting its requirement for **synchronized reserve** available within ten minutes, Appendix 3 provides guidance for eliminating the deficiency.

5.6 Distribution of **Reserve**

Reserve available to a Balancing Authority shall be distributed so as to ensure that it can be utilized without exceeding individual element ratings or transfer limitations.

5.7 Activation of Inter-Balancing Area **Reserve**

When a Balancing Authority acquires **reserve**, through direct procurement, bilateral or multi-lateral operating agreements, or through reserve sharing

agreements from another Balancing Authority, the provider of the **reserve** shall deliver an increase in energy equal to the amount of **reserve** acquired when the acquiring Balancing Authority requests its activation. Unless the provider experiences its own contingency, it shall not initiate the curtailment of an existing or planned energy sale to any Balancing Authority to support the activation of the **reserve** that was acquired until the contingent Balancing Authority has recovered from the contingency. **Reserve** acquired from another Balancing Authority shall be sustainable as specified in section 5.13.

Inter-Balancing Area **reserve** may be acquired by NPCC Balancing Authorities beyond that specified in section 5.8. All activations of inter-Balancing Area **reserve** are subject to the following constraints:

- Decision-making related to the specific resources to be activated to provide inter-Balancing Area **reserve** is restricted to the affected Balancing Authorities.

- Due to the potential difficulties in managing interchange schedules in a timely and consistent manner and in monitoring the deliverability of inter-Balancing Area **reserve** with intermediary Balancing Authorities and Reliability Coordinators, the provision of inter-Balancing Area **reserve** shall be limited to adjacent Balancing Authorities only, unless specifically facilitated by an approved NPCC procedure or multilateral Balancing Authority/Reliability Coordinator procedure.

- The activation of inter-Balancing Area **reserve** shall be implemented by either step changes to interchange schedules, by normal ramping of interchange schedules or by dynamic transfers. Where dynamic transfers are used to activate inter-Balancing Area **reserve**, it must be agreed to by the affected Balancing Authorities, and approved by the TFCO. Host and acquiring Balancing Authorities and Reliability Coordinators may establish and document further restrictions for these activation techniques.

- If inter-Balancing Area **reserve** is utilized for a Disturbance Control Standard recovery or an NPCC **reportable event**, it shall be activated within 5 minutes of the disturbance.

- The Balancing Authority acquiring **reserve** from a host Balancing Authority shall continually update the host Balancing Authority and affected Reliability Coordinators with any changes to the scheduling of inter-Balancing Area **reserve**.

- When inter-Balancing Area **reserve** is activated, the acquiring Balancing Authority notifies the host Balancing Authority to agree on interchange schedule modifications, and the host Balancing Authority activates the

reserve. **Reserve** activation is subject to the concurrence of the affected Reliability Coordinators.

- When an energy transaction associated with Inter-Balancing Area **reserve** terminates at the end of a scheduling period (i.e., the **reserve** is not scheduled in the subsequent scheduling period), the Balancing Authorities participating in the transaction shall agree on the terms of the schedule change in advance. As a minimum, these terms shall address the start time, ramp rate, and duration of the curtailment of the **reserve** being delivered.

5.8 Simultaneous Activation of **Ten-Minute Reserve**

Simultaneous activation of **ten-minute reserve** (SAR) is a program in which two or more Balancing Authorities agree to individually maintain but jointly activate **ten-minute reserve** to facilitate a more rapid recovery from an NPCC Reportable Contingency (500 MW or greater; 300 MW or greater for New Brunswick) or for stressed system conditions. Balancing Authority participation in SAR is contingent on submission of the form located in Appendix 7 and approval by Task Force on Coordination of Operation. This form will also be used to indicate if a Balancing Authority wishes to act as the SAR Coordinator for the SAR program, contingent upon the approval of TFCO. All participating Balancing Authorities in the SAR program shall form an electrically contiguous area. Adjacent and directly connected non NPCC Balancing Authorities may participate in the Simultaneous Activation of Ten- Minute Reserve program described in this Directory.

Given that **reserve** is not shared under this arrangement, the SAR program is not a Reserve Sharing Group as defined by NERC.

Recovery from a large loss of resource(s) can be achieved faster by simultaneously activating **ten-minute reserve** in several Balancing Areas. Assisting Balancing Authorities provide SAR energy by implementing schedule changes with a zero ramp time, assuring that the reserve being activated responds as quickly as possible. Simultaneous activation of **ten minute reserve** is implemented in order to:

- more quickly relieve the initial stress placed on the interconnected transmission system following a large loss of **generation** or energy purchase
- effect an improvement in **reliability** achieved by the faster recovery
- assist in achieving compliance with the NERC Disturbance Control Standard (DCS)

- provide relief for transmission overloads, low voltage, or other abnormal conditions which evolve over time without an actual contingency, but might not otherwise be relieved by normal **reserve** pickup response**.**

When the resource loss is a generator, the contingent Balancing Authority's loss equals the total output of the generator irrespective of any energy or capacity sales from that generator to any other Balancing Authority. See Appendix 4 for guidance related to resource losses that occur at a specific point of delivery, and the source Balancing Authority cannot deliver energy on another path.

Balancing Authorities that participate in the Simultaneous Activation of Reserve program shall do so in accordance with the requirements in sections 5.8.1 through 5.8.6 below. Contingent Balancing Authorities are solely responsible for their DCS recovery.

5.8.1 Preliminary **Reserve** Assessment

On a continuing basis, participating Balancing Authorities shall keep the SAR Coordinator(s) informed of the largest, single **generation** or import energy transaction **contingency** in their respective Balancing Areas.

Information pertaining to a Balancing Authority's inability to participate in SAR shall be reported to the SAR Coordinator by the participating Balancing Authorities.

5.8.2 Notification of Contingency

A participating Balancing Authority may choose to implement the SAR program if it experiences a loss of **generation** or imported energy transactions equal to or greater than an NPCC **reportable event**, or for stressed system conditions.

A participating Balancing Authority that suffers a contingency meeting the activation threshold and wishes to receive SAR assistance shall report the following information to the SAR Coordinator via the direct telephone lines:

- Time T+0 (see below)
- If applicable, name of generating resource and megawatts lost
- If applicable, name of energy purchase and megawatts lost
- Megawatts of assistance requested including that provided by the Contingent Balancing Authority
- Cause of SAR request.

For a loss of resource, T+0 is estimated to be consistent with the time specified in section 5.17 below, rounded to the nearest minute. This

estimate is for event identification purposes only, and the T+0 used for compliance determination will be performed after-the-fact, consistent with section 5.17 below. For system conditions not directly associated with a contingency, it is the time of the request for SAR assistance.

The contingent Balancing Authority shall request SAR assistance, providing sufficient time for the SAR Coordinator to distribute the shares, and for the assisting Balancing Authorities s to implement the schedule changes within five minutes of the contingency, allowing for a full 10 minutes to provide the reserve assistance assigned prior to the expiration of the 15 minute NERC Disturbance Recovery Period. This time constraint also applies for NPCC **reportable events** that are less than the Disturbance Control Standard reporting threshold.

5.8.3 Allocation of SAR

The SAR Coordinator shall assign 100% of the contingency to the Contingent and Assisting Balancing Authorities collectively. The SAR Coordinator shall assign allocations to the Assisting Balancing Authorities that are within their respective response capability.

After receiving a request for the activation of SAR, the SAR Coordinator shall:

a. Determine each Balancing Authority's SAR allocation in accordance with the following:
   - At least fifty percent (50%) of a loss is allocated to the Contingent Balancing Authority.
   - The remainder of a loss is normally allocated among the Assisting Balancing Authorities.
   - A Balancing Authority shall not be requested to provide more assistance during a **reserve** pickup than is required to meet its own largest **contingency**.

b. Immediately inform each Balancing Authority of its SAR allocation, the time that the schedule change is effective, and the time that the **contingency** occurred.

c. SAR participants may activate additional **reserve** beyond the SAR allocations to assure that the needed **ten minute reserve** is provided successfully. The Balancing Authority receiving SAR assistance may activate additional reserve to prepare for the eventual withdrawal of SAR assistance.

5.8.4 Provision of SAR Assistance

Assisting Balancing Authorities shall initiate immediate action to provide their allocated SAR assistance**.**

The Contingent Balancing Authority shall initiate immediate action to provide its share assigned by the SAR Coordinator to recover from the resource loss, and the Contingent Balancing Authority shall prepare for the replacement of the SAR assistance energy assigned to assisting Balancing Authorities.

Assisting Balancing Authorities shall activate **ten-minute reserve** and provide assistance by **interchange schedules** that are:

a. Implemented at a zero time ramp rate immediately following allocation notification.

b. Maintained until the Contingent Balancing Authority requests a return to normal up to a maximum of thirty minutes.

c. Sustained, from the time of implementation, for a minimum of ten minutes unless reliability is affected adversely.

5.8.5 Termination of SAR

The Contingent Balancing Authority shall notify the SAR Coordinator when it wishes to terminate the delivery of SAR assistance.

- The SAR Coordinator shall notify all participating Balancing Authorities and confirm the time that the activation is terminated. Revised **interchange schedules** are mutually established as required so that the Assisting Balancing Authorities properly recall assistance.
- The Contingent Balancing Authority shall replace the **reserve** assistance assigned to assisting Balancing Authorities in a manner consistent with mutually established **interchange schedules**.
- **Interchange schedules** associated with SAR shall be ramped out at a ten-minute ramp rate following communications initiated by the Contingent Balancing Authorities, resulting in mutually established **interchange schedules**.
- In the event that a Contingent Balancing Authority is not prepared to replace the remaining portion of its **reserve** obligation within the time specified in section 5.8.4, the Contingent Balancing Authority shall arrange for additional assistance in accordance with applicable policies and agreements covering **interchange** and **emergency** assistance.

5.8.6 Reallocation and/or Subsequent **Contingencies**

In the event that the reliability of an Assisting Balancing Authority becomes jeopardized, that Balancing Authority may cancel all or part of its allocation (using a step schedule change) by notifying the SAR Coordinator, which shall then notify the Contingent Balancing Authority to increase its SAR allocation to replace the assistance that has been withdrawn.

In the event that a subsequent loss of **generation** or imported energy transaction occurs during the period when SAR is in progress, regardless of the size of the **contingency**, the second Contingent Balancing Authority may, at its discretion, withdraw SAR assistance and request the SAR Coordinator to reallocate the assistance in accordance with the provisions of this procedure. Upon such notification, the SAR Coordinator shall notify the first Contingent Balancing Authority of the amount of withdrawal. Both Contingent Balancing Authorities shall immediately enter new **interchange schedules** that reflect the loss of the assistance, using a zero time ramp.

In the event that a second Balancing Authority experiences a **contingency** that qualifies for SAR, the SAR Coordinator shall allocate assistance from the remaining Assisting Balancing Authorities in accordance with this procedure, upon the request of that Contingent Balancing Authority.

If the second **contingency** occurs in the Balancing Authority that has incurred the first **contingency**, that Balancing Authority may request additional assistance, in accordance with this procedure, regardless of the size of the **contingency**.

5.9 Energy Scheduling and Managing **Reserve**

A Balancing Authority shall meet its requirement for **reserve** using resources within its Balancing Area and/or obtain deliverable **reserve** from other Balancing Authorities.

When a Balancing Authority acquires energy from another Balancing Authority that is immediately recallable, the acquiring Balancing Authority:

a. shall not use such energy to meet its **reserve** requirements, and resources displaced by the energy must remain available to cover for the curtailment of said energy at any time; and,

b. shall adjust its **ten-minute reserve** requirement to cover the larger of the Balancing Authority's **first contingency loss**, or the largest sum of such energy acquisitions that could be withdrawn at the same time due to a single contingency or event.

A Balancing Authority acquiring energy not associated with the capacity used to meet **reserve** requirements of another Balancing Authority is the only Balancing Authority that can use this energy to augment its **reserve**. The Balancing Authority providing such energy is obligated to advise the acquiring Balancing Authority of any change in the surplus status of the energy.

5.10 Requirements for **Reserve on Automatic Generation Control (AGC)**

Balancing Authorities shall have available and deploy sufficient **reserve on Automatic Generation Control (AGC)** to meet NERC control performance standards. R**eserve on Automatic Generation Control (AGC)** shall be sustainable as specified in section 5.13. NPCC Balancing Authorities operating synchronously within the Eastern Interconnection may meet a portion of their requirements for **reserve on Automatic Generation Control (AGC)** by participating in ACE Diversity Interchange as described in section 5.11. See Appendix 5 for the NPCC control performance standard reporting processes.

5.11 ACE Diversity Interchange

ACE Diversity Interchange (ADI) is a method of regional regulation among participating Balancing Authorities that can achieve a mutual reduction in requirements for **reserve on Automatic Generation Control (AGC)** and generator output adjustments. ADI uses the sign diversity of the Area Control Error (ACE) values of the participating Balancing Authorities to achieve this mutual reduction. ADI is a form of supplemental regulation as permitted by NERC Standards.

All participating Balancing Authorities in ACE Diversity Interchange shall form an electrically contiguous area. Adjacent and directly connected non NPCC Balancing Authorities may participate in ACE Diversity Interchange. Participation in ACE Diversity Interchange is contingent on submission of the form located in Appendix 7 and approval by TFCO.

This form will also be used to indicate if a Balancing Authority wishes to act as the ADI Coordinator for the ADI participants, contingent upon the approval of TFCO.

Balancing Authorities that participate in Ace Diversity Interchange (ADI) shall do so in accordance with the requirements in section 5.11.1 & 5.11.2 below.

5.11.1 ADI General Requirements

In order to participate in ADI, Balancing Authorities shall establish the appropriate data exchange and apply the ADI term to their respective ACE in AGC.

Transmission limits or other internal constraints that preclude the normal implementation of ADI shall be communicated immediately to the ADI Coordinator. Whenever normal implementation of the procedure is precluded, the ADI Coordinator shall notify the other participants.

The industry sign standard for ACE is used, i.e., a negative ACE indicates under-generation. The ADI sign convention is such that a positive ADI allocation will make the adjusted ACE of the participating Balancing Authority less negative with respect to the unadjusted ACE. The positive ADI limit will restrict the amount of positive ADI that can be allocated to make a participating Balancing Authority's adjusted ACE less negative with respect to a negative unadjusted ACE. The converse is applied to positive ACE values and negative ADI allocation and limits.

Inadvertent interchange is affected by the implementation of ADI. In general the unadjusted ACE values have equal likelihood over an hour to be positive or negative. ADI allocations will be monitored carefully for inequitable or inordinately large accumulations of inadvertent. These issues will be addressed and remedied promptly.

ADI may be biased to correct for inadvertent among participants that have accumulated balances that are opposite in sign. Two or more ADI participants may engage in this activity. At least one participant's accumulated inadvertent balance must be opposite in sign to the other's.

5.11.2 ADI Methodology

Changes to the ADI states (enable/disable) and parameters are coordinated through the ADI Coordinator. The ADI Coordinator has the authority to globally disable ADI. Following this action, all participants shall be notified. A change to an individual participating Balancing Authority's enable/disable status is communicated electronically and is available to all participants.

The participating Balancing Authorities have the authority to disable their respective participation in ADI. The ADI Coordinator has the capability to disable any individual participating Balancing Authority, but shall only do so at the participating Balancing Authority's request, unless a reliability problem requires immediate action by the ADI Coordinator.

a) The ADI Coordinator notifies all participating Balancing Authorities of any changes in a participating Balancing Authority's ADI state.
b) The ADI Coordinator has the authority to enable or disable ADI exchange and/or related parameters if:

- Control Performance is adversely affected by the ADI
- ADI contributes to inordinately large or inequitable accumulations of inadvertent
- Flows on the transmission system are affected adversely by ADI.
- Data received from a participating Balancing Authority do not meet the data refresh criterion.

c) Participating Balancing Authorities determine their level of participation in conjunction with the NPCC Working Group CO-1. ADI values that determine the limit for total ADI participation shall be recommended by NPCC Working Group CO-1 and require approval by the TFCO. All changes that affect ADI participation must be communicated through the ADI Coordinator. Limit changes to control inadvertent accumulations will be made simultaneously by the ADI Coordinator and communicated to all participants.
d) Any Participating Balancing Authority may request that ADI be enabled or disabled globally.
e) All actions to globally enable or disable ADI or otherwise modify ADI parameters shall be communicated by the ADI Coordinator to the other ADI participants. A concise reason for the change is to be given.
f) Participating Balancing Authorities will disable ADI participation if AGC execution is paused, suspended, placed in a monitor mode, or if data quality problems result in an unreliable calculation of the unadjusted ACE.
g) The NPCC Control Performance Working Group (CO-1) shall monitor the ADI process to determine the appropriate ADI operating parameters and to assure that reliability is not adversely affected by its use. CO-1 shall periodically verify that unadjusted ACE values used for ADI assignments are reasonably close to an equal distribution of positive and negative values, and monitor ADI monthly on and off peak accumulations to assure that inadvertent accumulations are not experiencing a significant adverse impact. CO-1 will assure that any increase in ADI limits will not have an adverse impact on reliability, and will coordinate any limit and parameter changes with NPCC CO-8 members of participating Balancing Authorities.
h) As ADI is treated as a pseudo-tie, data retention requirements shall match those specified for tie-line data in accordance with applicable NERC standards.

5.12 Frequency Responsive **Reserve**

See Appendix 1 for NPCC-specific reporting procedures.

5.13 Sustainability of **Operating Reserve**

Synchronized reserve, **ten-minute reserve**, and **thirty-minute reserve** available to a Balancing Authority, if activated, shall be sustainable for at least one hour from the time of activation. Balancing Authorities shall determine their sustainability requirement for reserve on Automatic Generation Control (AGC) based on their ability to achieve compliance with relevant standards, with due consideration of their operating characteristics.

5.14 Resource-Specific Requirements

The Balancing Authority is responsible for meeting the following:

a) **Synchronized reserve**, **ten-minute reserve**, and **thirty-minute reserve** cannot be provided from loads where the same capacity is included in demand response programs and would result in double counting the same capacity.
b) Loads cannot provide **synchronized reserve** if the reduction in load is dependent on starting a generator to replace energy that is supplied from the grid.
c) To be eligible to provide **synchronized reserve**, **ten-minute reserve**, or **thirty-minute reserve**, the Load Serving Entity or Generator Owner responsible for the **Resource** shall meet the metering and testing requirements of the relevant Balancing Authorities.
d) To be eligible to provide **synchronized reserve**, **ten-minute reserve**, or **thirty-minute reserve**, the **Resource** shall continuously meet the dispatch instruction requirements of the relevant Balancing Authority(s).
e) To be eligible to provide **synchronized reserve**, **ten-minute reserve**, or **thirty-minute reserve**, the Load Serving Entity or Generator Owner responsible for the **Resource** shall meet the requirements specified by the relevant Balancing Authorities for operating limits and response rate, so that available **reserve** shall be computed accurately.
f) To be eligible to provide **synchronized reserve**, **ten-minute reserve**, or **thirty-minute reserve**, the Load Serving Entity or Generator Owner responsible for the **Resource** providing inter-Balancing Area **reserve** shall not offer the same reserve to more than one acquiring Balancing Authority for the same scheduling interval.
g) When energy and **reserve** are being provided concurrently from a **Resource** for a host and acquiring Balancing Authority respectively, a host Balancing Authority providing inter-Balancing Area **reserve** cannot count that **reserve** to

meet its own **reserve** requirement, and, the acquiring Balancing Authority cannot count capacity that is allocated for energy to the host Balancing Authority as **reserve**.

5.15 Reporting of Simultaneous Activation of **Reserve** Events

Contingent Balancing Authorities initiating a SAR event have successfully recovered when their ACE crosses zero (or returns to the ACE value just prior to the loss of resource if it was negative) within 15 minutes of the occurrence of the contingency.

Assisting Balancing Authorities have successfully provided their assistance if either of the following conditions exists:

(1) ACE crosses zero after the step schedule change to provide their assistance has been entered and within fifteen minutes of the time of the contingency, or;
(2) If their ACE was negative just prior to the step schedule change to provide their assistance, their ACE returns to the negative ACE value just prior to the schedule change and within fifteen minutes of the time of the contingency.

Assisting Balancing Authorities are not subject to the above recovery evaluations if the notification time for assistance supplied by the SAR Coordinator is not less than five minutes from the time of contingency.

If an assisting Balancing Authority has not provided its assistance successfully per either (1) or (2) above, and, the notification time was within five minutes of the occurrence of the contingency, then the assisting Balancing Authority shall provide a written explanation to the TFCO. If an assisting Balancing Authority incurs 3 shortfalls within the most recently completed twelve months, TFCO is empowered to take actions they deem to be appropriate up to and including termination from future participation in the SAR program. See Appendix 2 for reporting details.

If a Balancing Authority receiving or providing assistance experiences a resource loss when an SAR event is in progress, that Balancing Authority may adjust their ACE by the amount of the resource loss and use that adjusted ACE in the evaluation of the success of its recovery.

5.16 Light Load Conditions

Guidance for mitigating adverse light load conditions is provided in Appendix 6.

5.17 Determining the Time Associated With the Loss of a Resource

The determination of time T+0 for resource losses is consistent with the methodology described in the NERC Performance Standard Reference Guide. For performing compliance evaluations, time T+0 for NPCC Reportable Events is determined by the following process:

1. A sliding 60 second interval (with EMS scan rate data as a source) is used to determine when the magnitude of the resource loss qualifies as an NPCC Reportable Event.
2. When the change in output of the resource loss exceeds the NPCC Reportable Event Threshold within a sliding 60 second interval, time T+0 is the first observation of declining output within that sliding 60 second interval.
3. When the change in output of the resource loss exceeds the DCS Event Threshold within a sliding 60 second interval, time T+0 is the first observation of declining output within that sliding 60 second interval.
4. If (2) and (3) above result in differing computations of T+0, the DCS computation in (3) takes precedence.
5. Any portion of the resource loss preceding the sliding 60 second interval identified in (2) and/or (3) is not included in the determination of the megawatts lost for the event.

Prepared by: Task Force on Coordination of Operation

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of the document such as Links glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References: *NPCC Glossary of Terms* (Document A-7)
Emergency Operations (NPCC Directory #2)

Appendix 1 - Monitoring Procedures for Interconnected System Frequency Response

Introduction

The objective of this procedure is to provide a broader data base for further studies and to aid in the calculation of the observed frequency response. These frequency response observations are also used in determining the frequency bias settings to be used in the AGC systems of the NPCC Balancing Authorities. The NPCC Control Performance Working Group (CO-1) will monitor the results of all NPCC Balancing Authorities produced from the procedure.

Definition

For this reporting process, the system frequency deviation threshold specified for NPCC **reportable events** is used, but only those deviations occurring within 5 seconds are included in the analyses specified below.

Procedure

Balancing Authorities will record the following data for each reportable Frequency Deviation Event:

- date and time of the event
- pre-contingent Balancing Authority load
- Balancing Area response, which is the difference between the pre-contingent actual net interchange and the average actual net interchange during the post-event steady state period as defined below. (For HQTE, the Balancing Area response equals the magnitude of the **resource** loss.)
- pre-event frequency
- minimum transient frequency
- post-event steady-state frequency before AGC action.

The post event steady state period is typically between 12 seconds and 20 seconds following disturbance initiation. From this data, the following information will be derived:

- transient frequency deviation
- steady-state frequency deviation
- observed frequency response for the event

- frequency response as a percentage of pre-contingent Balancing Authority load

Data Reporting

Balancing Authorities will report events with a calculated frequency response (MW/ .1 Hz) that is less than 1% of the pre-contingent actual load on an annual basis.

To comply with NERC requirements for computing the frequency bias setting within AGC, the average value of the observed frequency response samples computed within this procedure is determined on an annual basis.

Data and results from this procedure are retained for at least 5 years.

Appendix 2 - Monitoring Procedures for Reserve Criteria

Introduction

This procedure establishes the monitoring and reporting processes for resource losses in addition to those required for meeting the NERC Disturbance Control Standard (DCS). NPCC Control Performance Working Group (CO-1) has primary responsibility for performing the monitoring and reporting processes described herein.

Monitoring Criteria

As an indication of adequacy **of ten-minute reserve**, the monitoring and reporting criteria for Balancing Authorities within NPCC focus on performance during **reportable events** where the supply side **resource** loss is equal to or less than the **first contingency loss**.

NBSO and NSPI function as a reserve sharing group for recovery from their larger losses of **resource**, the 80% threshold applies to the largest **first contingency loss** within their combined Balancing Areas.

All supply side **resource** losses that resulted in the utilization of Procedures for Simultaneous Activation of ten-minute reserve (SAR) are reported to and reviewed by CO-1.

Monthly Monitoring Procedures

For each **reportable event** not utilizing Simultaneous Activation of Reserve (SAR), an NPCC Area Trouble Report is completed by the Balancing Authority experiencing the contingency, using the appropriate reporting form. Balancing Authorities requesting SAR assistance complete the appropriate contingent SAR reporting form. Balancing Authorities providing SAR assistance complete the appropriate assistance SAR reporting form.

At the conclusion of each calendar month, NPCC Balancing Authorities review all of their **reportable events** and any SAR assistance that was provided. Each Balancing Authority sends an electronic copy of the report completed for each of their **reportable events** and any SAR assistance within a month to the Chair of CO-1 (or his/her designee). All reports in a month are due by the tenth calendar day of the following month.

Each month, CO-1 monitors the performance of the SAR program, including the timeliness of schedule changes, the successful provision of the assigned assistance, and any anomalies that may have occurred in each SAR event. CO-1 shall report any anomalies or performance shortfalls to the TFCO.

Quarterly Monitoring Procedures

The Chair (or his or her designee) of CO-1 compiles all monthly submissions at the end of each quarter to determine Disturbance Control Standard (DCS) compliance for all NPCC Balancing

Authorities. The DCS results are forwarded to the NERC office, the NPCC Compliance Committee, and to CO-1.

Annual Monitoring Procedures

CO-1 prepares an annual summary for the Task Force on Coordination of Operation (TFCO) indicating, for each Balancing Authority and for NPCC as a whole, the number of violations and the number of events for which performance was successful. The summary report also compares current year's performance with the performance of the four previous years. CO-1 provides supplementary information, as necessary, to the TFCO for their review.

The Chair of CO-1 (or his/her designee) on an annual basis produces an electronic archive of all reportable events, and distributes the archive to CO-1 members and NPCC Staff.

Appendix 3 - Procedures during Abnormal Operating Conditions

1.0 Introduction

This procedure provides specific instructions to Balancing Authorities for: making notifications upon the occurrence of deficiencies in **reserve;** restoration of **ten minute reserve**, **synchronized reserve** available within ten minutes, and **thirty minute reserve;** addressing persisting deficiencies of **ten-minute reserve;** and, addressing a regional deficiency of **ten-minute reserve.**

2.0 Objectives

2.1 To mitigate the impact of an evolving event.

2.2 To alert other Balancing Authorities and Reliability Coordinators when any Balancing Authority is deficient, or anticipates being deficient, in **reserve**.

2.3 To enhance reliability within NPCC through the sharing of resources when any Balancing Authority becomes deficient in **ten-minute reserve** and cannot restore it in a timely manner as described in section 5.2 of Directory 5.

2.4 To return to normal operating conditions as soon as possible.

3.0 Action to Mitigate Ten-Minute Reserve Shortages

Procedures to address shortages of **ten-minute reserve** are provided in this section.

3.1 Actions When Becoming Deficient in **Ten-Minute Reserve**

To minimize the magnitude and duration of **ten-minute reserve** deficiency, a Balancing Authority may implement any or all of the actions below, in no implied order:

- Commit sufficient off-line supply-side **resources** to create additional **ten-minute reserve** within the restoration period specified in section 5.2 above.
- Recall applicable exports respecting Balancing Authority operating procedures. The source Balancing Authority of the applicable exports shall give proper notification to the sink Balancing Authority**.**
- Obtain additional **resources** from outside the Balancing Authority in accordance with regional and local practices. These additional **resources** shall not be from the portion of another Balancing Authority's **reserve** that is needed to meet the other Balancing Authority's **reserve** requirements in coincident hours.
- Recall planned generator outages and coordinate with the Reliability Coordinator for possible assistance available by recalling transmission outages

(or taking other actions) that will increase **reserve** or **transfer capability** if it can reasonably be expected that additional **resources** are available to assist in reducing or eliminating the shortage.

- Count **interruptible load** (not firm **load**) that can be interrupted within ten minutes in its **ten-minute reserve**, if it has not already been counted.
- Count voltage reduction that can be implemented within ten minutes in its **ten-minute reserve**, if it has not already been counted.
- Consider the use of Public Appeals if sufficient time exists to activate them, or if the shortage is expected to last for an extended period.

3.2 Deficiencies of the **Synchronized Reserve** Available Within Ten Minutes

When a Balancing Authority becomes deficient in the **synchronized reserve** available within ten minutes but is not deficient in **ten-minute reserve**, the deficient Balancing Authority considers any or all of the following actions in no implied order to eliminate or minimize the deficiency as soon as practical:

- Activate off-line generation to increase the supply of the **synchronized reserve available within ten minutes**.
- Re-dispatch online generation to increase the supply of the **synchronized reserve** available within ten minutes.
- Obtain additional **resources** from outside the Balancing Area in accordance with regional and local practices. These **resources** cannot be from the portion of another Balancing Authority's **reserve** that is needed to meet the other Balancing Authority's **reserve** requirements in coincident hours.
- Disconnect **interruptible load** (not firm **load**), which are not contributing to the **synchronized reserve** available within ten minutes due to implementation delays in excess of ten minutes, if permitted by market and other applicable rules.

3.3 Notifications

When a Balancing Authority becomes deficient or forecasts a deficiency in either the **synchronized reserve** available within ten minutes or **ten-minute reserve**, and, the Balancing Authority cannot restore these reserves using the actions specified in section 3.1 and 3.2 of this Appendix, the following actions are required:

- The Balancing Authority informs its Reliability Coordinator.
- The Reliability Coordinator considers the need to initiate, or request NPCC Staff to initiate, an NPCC Emergency Preparedness Conference Call among the Reliability Coordinators of NPCC, and PJM and MISO if necessary.

These actions are repeated whenever there is a change in the status of the available **reserve** with respect to their corresponding restoration requirements specified above.

3.4 Persisting Deficiency of **Ten-Minute Reserve**

If the Balancing Authority remains deficient after implementing all of the applicable actions stated above, the Balancing Authority notifies its Reliability Coordinator so that the Reliability Coordinator may request that the NPCC Staff survey each Balancing Authority to complete the information in Attachment A, providing each Balancing Authority's **first contingency loss**, **ten-minute reserve** and its requirement**, thirty-minute reserve** and its requirement, and each Balancing Authority's **Total Transfer Capability (TTC)** to and from other Balancing Authorities. In response to the above notification from the Balancing Authority, its Reliability Coordinator coordinates the transfer of emergency energy between Balancing Authorities so that the deficient Balancing Authority will ultimately increase the **ten-minute reserve** available to it.

3.5 Regional Deficiency of **Ten-Minute Reserve**

When two or more NPCC Balancing Authorities are deficient in **ten-minute reserve** and all off line generation that could contribute to alleviating the shortages in the deficient Balancing Authorities has been activated, then a **Regional Reserve Deficiency** is declared. During a **Regional Reserve Deficiency**, the Regional Reserve Deficiency Coordinator performs a manual **Emergency Regional Reserve Re dispatch**, allocating **Emergency Regional Reserve Dispatch Energy** (as energy or capacity) optimally among NPCC Balancing Authorities, coordinating available resources within or between Balancing Authorities:

- To provide for greater transfer capability between the Balancing Authorities**.**
- To free transmission-constrained energy and/or capacity.
- To allocate the remaining **ten-minute reserve** among the Balancing Authorities in a manner which will improve reliability, considering each Balancing Authority's ability to control schedules at its electrical boundaries and the Balancing Authority's ability to recover from its **first contingency loss.**

An NPCC Reliability Coordinator serves as the Regional Reserve Deficiency Coordinator. To serve as the Regional Reserve Deficiency Coordinator, an NPCC Reliability Coordinator shall submit a form requesting this role as described in Appendix 7, subject to approval by TFCO.

3.6 Actions When Becoming Deficient in **Thirty-Minute Reserve**

To minimize the magnitude and duration of a **thirty-minute reserve** deficiency, a Balancing Authority may implement any or all of the actions below, in no implied order:

- Obtain additional **resources** from outside the Balancing Authority in accordance with regional and local practices. These additional **resources** shall not be from the portion of another Balancing Authority's **reserve** that is

needed to meet the other Balancing Authority's **reserve** requirements in coincident hours.

- Recall planned generator outages and coordinate with the Reliability Coordinator for possible assistance available by recalling transmission outages that will increase **reserve** or **transfer capability** if it can reasonably be expected that additional resources are available to assist in reducing or eliminating the shortage.
- Recall applicable exports or convert applicable exports to a recallable product and include this energy and/or capacity in its **thirty-minute reserve,** while respecting Balancing Authority operating procedures. The source Balancing Authority of the applicable exports gives proper notification to the sink Balancing Authority if this action is taken**.**
- Count **interruptible load** (not firm **load**) that can be interrupted within thirty minutes in its **thirty-minute reserve**, if it has not already been counted.
- Count voltage reduction that can be implemented within thirty minutes in its **thirty-minute reserve**, if it has not already been counted.

3.7 Actions When Forecasting a Deficiency Of **Thirty Minute Reserve**

- Count additional **resources** from outside the Balancing Authority in accordance with regional and local practices. These additional **resources** shall not be from the portion of another Balancing Authority's **reserve** that is needed to meet the other Balancing Authority's **reserve** requirements in coincident hours.
- Obtain additional resources from inside the Balancing Authority in accordance with regional and local practices.

Attachment A

Reserve Summary

Area	First Contingency Loss	Required 30 Minute Reserves	Available 30 Minute Reserves	Required 10 Minute Reserves	Available 10 Minute Reserves
Maritimes					
Michigan					
NE					
NY					
Ontario					
PJM					
Québec					

Total Transfer Capability

To >	Mar.	Mich.	NE	NY	Ontario	PJM	Québec
From:							
Maritimes							
Michigan							
NE							
NY							
Ontario							
PJM							
Québec							

Appendix 4 - Guidelines for SAR Allocation Following Radial Source Contingencies

1.0 Introduction

If the resource loss is an energy transaction being received from another Balancing Authority connecting via radial source lines and that energy can no longer be delivered at the point of delivery, the source Balancing Authority has no practical means of replacing that energy. The energy that was sinking in the other Balancing Authorities must be replaced in a timely manner.

2.0 Handling of Radial Source Contingencies with Several Balancing Authorities Receiving Energy

Radial source tie lines crossing Balancing Area boundaries may have energy delivered over these lines to more than one Balancing Authority. Handling of large contingencies on radial sources crossing Balancing Area boundaries is described in section 4 below. The methodology presented in section 4.0 below is a generic guide to be used for allocation of SAR assistance whenever a contingency occurs on a radial source tie line that results in more than one Balancing Authority losing an energy transaction. .

3.0 Radial Source Contingencies with Counter flow Transactions

Coincident with energy transactions delivered out of the Balancing Authority on radial source tie lines, countervailing transactions may be scheduled simultaneously into the Balancing Authority. The contingency loss of one of these lines when it is carrying counter flow transactions may be a relatively small net energy loss to the interconnection. However, the size of the individual counter flow transactions could be quite large. The methodology presented in section 4 below may be used for allocation of SAR assistance whenever radial line contingencies with counter flow transactions occur. In instances when the net of the scheduled transactions is less than the **reportable event** threshold, the net interchange schedules may be ramped out instead of using the SAR procedure. The SAR Coordinator and the Balancing Authorities party to the transactions may agree to this action and the duration of the ramp.

4.0 SAR Allocations for Radial Source Contingencies with More Than One Balancing Authority Receiving Energy

Some of the radial source tie lines crossing Balancing Area boundaries from HQTE to NYISO, ISO-NE, and NBSO have maximum transfer capabilities in excess of the Balancing Authority's single largest internal capacity contingency. Energy may be delivered over these lines to more than one Balancing Authority, with transmission service being provided by the Transmission Service Provider for the Balancing Authority to which the respective line is directly connected. A Balancing Authority may limit the flow such that the loss would not exceed its largest single contingency to maintain

reserve requirements at reasonable levels. Transmission restrictions in other Balancing Authorities may also limit these flows.

As the delivering entity, HQTE has no practical means to provide **reserves** from its own system in the event of the loss of a radial source tie line. When only the directly connected Balancing Authority receives the delivery, it can treat the energy as an internal source and carry reserve to cover the sudden loss. However, when the energy is delivered to more than one Balancing Authority, the responsibility for the directly connected Balancing Authority to carry all of the reserve can become overly burdensome.

This section describes the handling of large contingencies on radial sources crossing Balancing Area boundaries, such as Hydro-Québec (HQTE) to NYISO. At times, these flows may be composed of simultaneous energy deliveries to the directly connected Balancing Authority and one or more other Balancing Authorities. It allows for the use of the SAR procedure to allocate the portion of energy not designated for the directly connected receiving Balancing Authority to other Balancing Authorities participating in the Simultaneous Activation of **Ten-Minute Reserve** Procedure.

This same methodology can be applied for scenarios with simultaneous imports and exports of energy (counter flow transactions) by one or more Balancing Authorities on radial sources crossing Balancing Area boundaries. The Balancing Authority losing its ability to deliver energy may receive negative assistance shares from other Balancing Authorities. In these scenarios, affected Balancing Authorities should require smaller generation changes to restore ACE while the procedure is in effect and should have a longer period to adjust fully after the contingency. The use of negative assistance is illustrated in examples 5 and 6 in Section 4.2 below.

4.1 Management of NPCC Radial Source Contingencies

SAR support for radial source contingencies will be limited to SAR participants. Radial Source transactions will be limited to only one intermediary Balancing Authority (BA) unless all Balancing Authorities on the scheduling path are SAR participants. Non-SAR participants are expected to recover energy sinking in their respective BAs in accordance with prevailing NERC Standards.

Each hour the SAR Coordinator must be notified of scheduled wheel-through transactions among SAR participants.

Due to current software limitations, the New Brunswick Balancing Authority is exempt from the requirement to provide hourly schedule information to the SAR Coordinator. Such information will be provided at the time of the contingency.

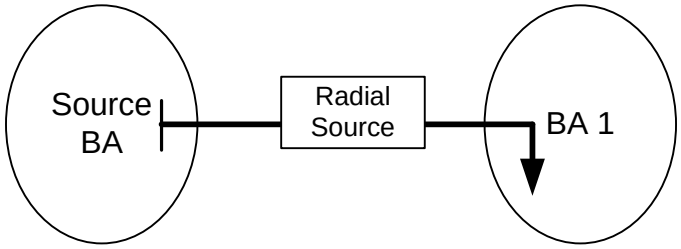
When SAR is requested, the SAR Coordinator will incorporate wheel-through transactions in its SAR software.

All ETAG(s) will be curtailed using phone communications by all applicable BAs.

E-tags will be maintained to account for the contingency and relevant SAR related activity. Four examples that apply to the management of Radial Source Contingencies that occur within NPCC for SAR and non-SAR events are provided below.

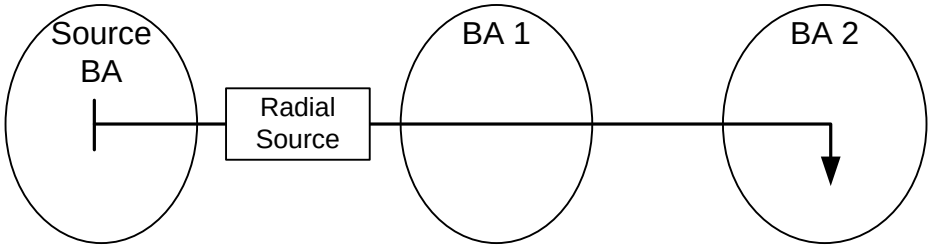
Example 1 Source BA and Sink BA1

The net energy flows from the radial Source BA and sinks in BA1 at the receiving end of that radial tie.	BA1 is responsible to recover for the entire loss as if the source was a generator inside the BA 1 footprint. Immediately following the contingency loss of the radial tie, the source and directly connected Balancing Authorities will verbally communicate. If the MW loss is greater than the NPCC reportable event threshold, or, if system conditions are stressed, BA1 may call for SAR. When SAR is requested, BA1 notifies the SAR Coordinator The ETAG(s) associated with the energy delivered to BA1 is curtailed immediately over a zero minute ramp due to the flow path being removed.



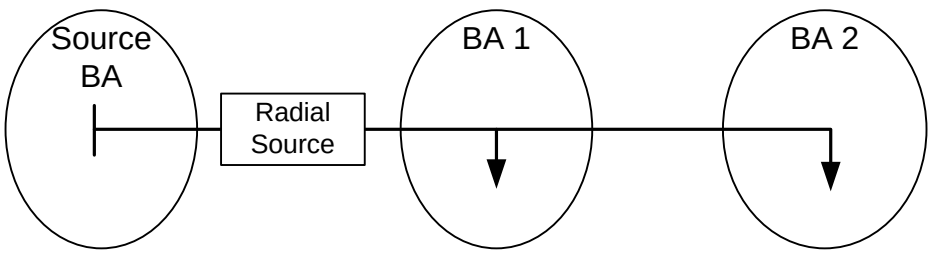
Example 2 Source BA, intermediary BA1, and sink BA2.

The net energy is wheeled from the radial Source BA through BA1 and sinks in BA2. This example applies to SAR participants.	BA2 is responsible to recover the MW sinking in its BA. Immediately following the contingency loss of the radial tie, the source and directly connected Balancing Authorities will verbally communicate. If the MW loss is greater than NPCC reportable event threshold, or for stressed system conditions, BA1 notifies the SAR Coordinator to request SAR activation. Verbal communications between the Balancing Authorities will be as follows: ▪ Pre-Contingency: BA1 will communicate BA2 schedule to SAR Coordinator ▪ Post Contingency: BA1 contacts SAR Coordinator to activate SAR. The SAR Coordinator issues shares. All ETAG(s) associated with the energy wheeled through BA1 and into BA2 will be curtailed upon termination of the SAR using a ten minute ramp. For non-SAR events: If SAR is not requested, all ETAG(s) associated with the energy wheeled through BA1 and into BA2 will be curtailed on a mutually agreed upon start time and ramp duration by the affected BAs.


Source
BA
Radial
Source
BA 1
BA 2

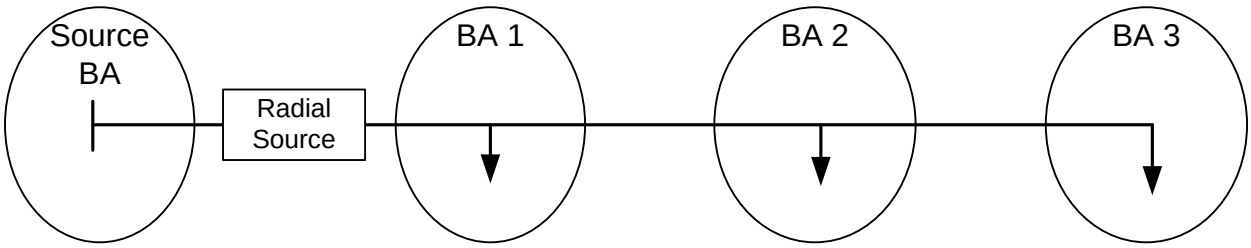
Example 3 Source BA, intermediary sink BA1, and sink BA2

The energy is flowing from the radial Source BA with portions sinking in BA1, and BA 2. This example applies to SAR participants.	BA1 and BA2 are responsible to recover the portions of the MW sinking in each of their BAs. Immediately following the contingency loss of the radial tie the source and directly connected Balancing Authorities will verbally communicate. If the net MW loss is greater than NPCC reportable event threshold, or for stressed system conditions, BA1 notifies the SAR Coordinator to request SAR activation. Verbal communications between the Balancing Authorities will be as follows: ▪ Pre-Contingency: BA1 will communicate the BA1 and BA2 schedules to SAR Coordinator ▪ Post Contingency: BA1 contacts SAR Coordinator to activate SAR. The SAR Coordinator issues shares. The ETAG(s) associated with the energy sinking in BA1 is curtailed immediately over a zero minute ramp due to the flow path being removed. The ETAG(s) associated with the energy wheeled through BA1 and sinking in BA2 will be curtailed upon termination of the SAR using a ten minute ramp. For non-SAR events: • The ETAG(s) associated with the energy sinking in BA1 is curtailed immediately over a zero minute ramp. • All ETAG(s) associated with the energy wheeled through BA1 and into BA2 will be curtailed on a mutually agreed upon start time and ramp duration by the affected BAs.



Example 4 Source BA, intermediary sink BA1, intermediary sink BA2, and sink BA3

The energy is flowing from the radial Source BA, with portions sinking in BA 1, BA 2, and BA3.	The rules governing this scenario are the same as presented in Example 3. Radial Source transactions will be limited to only one intermediary Balancing Authority (BA) unless all Balancing Authorities on the scheduling path are SAR participants.



4.2 Modification to the SAR Procedure

The SAR procedure is modified to allocate portions of the total delivery to Balancing Authorities in addition to the directly connected Balancing Authority during an ordinary simultaneous activation of reserve. When the tie line trips, the directly connected Balancing Authority activates the SAR procedure (if the loss exceeds the NPCC Reportable Event Threshold or for stressed system conditions), and then each recipient's share will be allocated to other participants based on the principle of mutual assistance, according to share allocation rules in the SAR procedure.

Each Balancing Authority receiving a portion of energy from the tie line through the directly connected Balancing Authority will contribute energy to and receive assistance for their portion of the contingency. The Balancing Authorities supplying this assistance would not have this energy replaced by the directly connected Balancing Authority when the directly connected Balancing Authority picks up its reserve to cover its energy import from HQTE. Thus, the directly connected Balancing Area's **reserve** requirement remains the greater of the largest internal contingency or its share of the respective tie line flow.

Initially, SAR shares would be calculated based on energy scheduled to the Balancing Authorities receiving energy from the tripped element. Initial shares

would be allocated to each energy recipient according to the ordinary share allocation rules in the SAR procedure. Thus each energy recipient is assigned one half of the energy received initially. A Balancing Authority would then receive additional allocations to provide assistance to each other Balancing Authority**,** until the total amount of the contingency is allocated.

Once recovery from the contingency occurs, the contingent and recipient Balancing Authorities provide the remainder of their respective **reserve** obligations. A recipient Balancing Authority uses its own generation to replace the energy initially received (unless additional alternative arrangements are made) after SAR assistance is withdrawn.

The methodology is iterative. One pass is required to allocate shares for each of the Balancing Authorities requiring assistance. Key features of the method are demonstrated in the examples below. NBSO participation is excluded from these examples for simplicity. The values shown are rounded to whole numbers.

Each SAR participant Balancing Authority receiving energy compares the energy sinking within its Balancing Authority with applicable NERC and NPCC reporting thresholds to determine their reporting requirements.

Example 1. PJM imports 400 MW from HQTE on MSC 7040, NYISO imports 1200 MW:

MSC 7040 flow = 1600 MW
HQTE – NYISO transaction = 1200 MW
HQTE – PJM transaction = 400 MW

Area	**Initial Share/ Assistance Sought**	**First Pass**	**Second Pass**	**Total Generation Picked Up When SAR Energy Is Supplied Fully**	**Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0**
IESO		200	67	267	0
ISO-NE		200	67	267	0
NYISO	600		67	667	1200
PJM	200	200		400	400
Sum	800	600	200	1600	1600

Initial Shares – NYISO and PJM are initially assigned one half of their respective energy imports from HQTE. Consequently, under the ordinary SAR rules, they would be 'seeking' assistance for an equal amount. The total assistance sought is 800 MW for the entire contingency amount.

First Pass – NYISO is provided 600 MW of assistance. These shares are allocated equally, 200 MW each, among the other three participants – including PJM.

Second Pass – PJM is provided 200 MW of assistance. These shares are allocated equally, 67 MW each, among the other three participants – including NYISO.

Total Generation Picked up – The additional generation in each Balancing Authority**,** after all Balancing Authorities provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Balancing Authority returns it ACE to zero is shown in the last column.

The table below summarizes the changes in schedule and ACE from just prior to the contingency, through the cancellation of assistance and full recovery by both Balancing Authorities losing energy due to the contingency. In practice, the SAR Coordinator merges the negation of the initial schedule (third row of numeric data) and the SAR share entries (fourth row of numeric data) into a single step to promote timely implementation, achieving the same desired net effect. Note that the ACE in step 4 matches the **Total Generation Picked Up When SAR Energy Is Supplied Fully** column in the previous table, but is opposite in sign.

Time	**IESO Sch**	**IESO ACE**	**NE Sch**	**NE ACE**	**PJM to NY Sch**	**PJM ACE**	**NY to PJM Sch**	**NY ACE**	**Tot Sch**	**Tot ACE**
Pre-contingency	0	0	0	0	-400	0	+400	0	0	0
Contingency	0	0	0	0	-400	0	+400	-1600	0	-1600
Negation of PJM/NY schedule	0	0	0	0	0	-400	0	-1200	0	-1600
No response, SAR entries	+267	-267	+267	-267	-200 +200 = 0	-400	-600 +67= -533	-667	0	-1600
Full response, SAR not canceled	+267	0	+267	0	0	0	-533	0	0	0
SAR just canceled	0	+267	0	+267	0	0	0	-533	0	0
All get back to ACE = 0	0	0	0	0	0	0	0	0	0	0

Note that IESO, ISO-NE, and NBSO model their HVDC radial tie line imports as an internal generator, and their ACE will immediately reflect the loss of resource. NYISO includes HQTE HVDC interchange schedules within its AGC system, so NYISO must set that schedule to zero as soon as possible so its ACE reflects the loss of resource.

Example 2. PJM imports 1200 MW from HQTE on MSC 7040, NYISO imports 400 MW:

MSC 7040 flow = 1600 MW
HQTE – NYISO transaction = 400 MW
HQTE – PJM transaction = 1200 MW

Area	**Initial Share/ Assistance Sought**	**First Pass**	**Second Pass**	**Total Generation Picked Up When SAR Energy Is Supplied Fully**	**Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0**
IESO		67	200	267	0
ISO-NE		67	200	267	0
NYISO	200		200	400	400
PJM	600	67		667	1200
Sum	800	200	600	1600	1600

Initial Shares – NYISO and PJM are initially assigned one half of their respective energy imports from HQTE. Consequently, under the ordinary SAR rules, they would be 'seeking' assistance for an equal amount. The total assistance sought is 800 MW for the entire contingency amount.

First Pass – NYISO is provided 200 MW of assistance. These shares are allocated equally, 67 MW each, among the other three participants – including PJM.

Second Pass – PJM is provided 600 MW of assistance. These shares are allocated equally, 200 MW each, among the other three participants- including NYISO.

Total Generation Picked up –The additional generation in each Balancing Authority**,** after all Balancing Authorities provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Balancing Authority returns it ACE to zero is shown in the last column.

The table below summarizes the changes in schedule and ACE from just prior to the contingency, through the cancellation of assistance and full recovery by both Balancing Authorities losing energy due to the contingency. In practice, the SAR Coordinator merges the negation of the initial schedule (third row of numeric data) and the SAR share entries (fourth row of numeric data) into a single step to promote timely implementation, achieving the same desired net effect. Note that the ACE in step 4 matches the **Total Generation Picked Up When SAR Energy Is Supplied Fully** column in the previous table, but is opposite in sign.

Time	IESO Sch	IESO ACE	NE Sch	NE ACE	PJM to NY Sch	PJM ACE	NY to PJM Sch	NY ACE	Tot Sch	Tot ACE
Pre-contingency	0	0	0	0	-1200	0	+1200	0	0	0
Contingency	0	0	0	0	-1200	0	+1200	-1600	0	-1600
Negation of PJM/NY schedule	0	0	0	0	0	-1200	0	-400	0	-1600
No response, SAR entries	+267	-267	+267	-267	-600 +67 =-533	-667	-200 +200 = 0	-400	0	-1600
Full response, SAR not canceled	+267	0	+267	0	-533	0	0	0	0	0
SAR just canceled	0	+267	0	+267	0	-533	0	0	0	0
All get back to ACE = 0	0	0	0	0	0	0	0	0	0	0

Note that IESO, ISO-NE, and NBSO model their HVDC radial tie line imports as an internal generator, and their ACE will immediately reflect the loss of resource. NYISO includes HQTE HVDC interchange schedules within its AGC system, so NYISO must set that schedule to zero as soon as possible so its ACE reflects the loss of resource.

Example 3. PJM and NYISO each import 200 MW from Québec on Sandy Pond, NE imports 1200 MW:

Sandy Pond flow =	1600 MW
HQTE – NY transaction =	200 MW
HQTE – NE transaction =	1200 MW
HQTE – PJM transaction =	200 MW

Area	**Initial Share/ Assistance Sought**	**First Pass**	**Second Pass**	**Third Pass**	**Total Generation Picked Up When SAR Energy Is Supplied Fully**	**Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0**
IESO		200	33	33	267	0
ISO-NE	600		33	33	667	1200
NYISO	100	200		33	333	200
PJM	100	200	33		333	200
Sum	800	600	100	100	1600	1600

Initial Shares – ISO-NE, NYISO and PJM are initially assigned one half of their respective energy imports from HQTE. Consequently, under the ordinary SAR rules, they would be 'seeking' assistance for an equal amount. The total assistance sought is 800 MW for the entire contingency amount.

First Pass – ISO-NE is provided with 600 MW of assistance. These shares are allocated equally, 200 MW each, among the other three participants.

Second Pass – NYISO is provided 100 MW of assistance. These shares are allocated equally, 33 MW each, among the other three participants.

Third Pass – A third pass is now required to allocate assistance shares to the third component of the contingency. PJM is provided 100 MW of assistance. These shares are allocated equally, 33 MW each, among the other three participants.

Total Generation Picked up – The additional generation in each Balancing Authority**,** after all Balancing Authorities provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Balancing Authority returns it ACE to zero is shown in the last column.

The table below summarizes the changes in schedule and ACE from just prior to the contingency, through the cancellation of assistance and full recovery by both Balancing Authorities losing energy due to the contingency. In practice, the SAR Coordinator merges the negation of the initial schedules (third row of numeric data) and the SAR

share entries (fourth row of numeric data) into a single step to promote timely implementation, achieving the same desired net effect. Note that the ACE in step 4 matches the **Total Generation Picked Up When SAR Energy Is Supplied Fully** column in the previous table, but is opposite in sign.

Time	IESO Sch	IESO	NE Sch	NE ACE	PJM Sch	PJM ACE	NY Sch	NY ACE	Tot Sch	Tot ACE
Pre-contingency	0	0	+400	0	-200	0	-200	0	0	0
Contingency	0	0	+400	-1600	-200	0	-200	0	0	-1600
Negation of PJM/NY/NE schedules	0	0	0	-1200	0	-200	0	-200	0	-1600
No response, SAR entries	+267	-267	-600 +33 +33= -533	-667	-100 +200 +33= +133	-333	-100 +200 +33= +133	-333	0	-1600
Full response, SAR not canceled	+267	0	-533	0	+133	0	+133	0	0	0
SAR just canceled	0	+267	0	-533	0	+133	0	+133	0	0
All get back to ACE = 0	0	0	0	0	0	0	0	0	0	0

In the table above, NE Sch represents the sum of the energy exports wheeled from HQTE through ISO-NE to NYISO and PJM. PJM Sch represents the energy being wheeled from HQTE through ISO-NE and NYISO for PJM. NY Sch represents the energy being wheeled from HQTE through ISO-NE for NYISO.

Note that IESO, ISO-NE, and NBSO model their HVDC radial tie line imports as an internal generator, and their ACE will immediately reflect the loss of resource. NYISO includes HQTE HVDC interchange schedules within its AGC system, so NYISO must set that schedule to zero as soon as possible so its ACE reflects the loss of resource.

Example 4. ISO-NE, PJM and NYISO each import 700 MW each from Québec on Sandy Pond:

Sandy Pond flow =	2100 MW
HQTE – NYISO transaction =	700 MW
HQTE – ISONE transaction =	700 MW
HQTE – PJM transaction =	700 MW

Area	**Initial Share/ Assistance Sought**	**First Pass**	**Second Pass**	**Third Pass**	**Total Generation Picked Up When SAR Energy Is Supplied Fully**	**Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0**
IESO		117	117	117	350	0
ISO-NE	350		117	117	584	700
NYISO	350	117		117	584	700
PJM	350	117	117		584	700
Sum	1050	350	350	350	2100	2100

Initial Shares – ISO-NE, NYISO, and PJM are initially assigned one half of their respective energy imports from HQTE. Consequently, under the ordinary SAR rules, they would be 'seeking' assistance for an equal amount. The total assistance sought is 1050 MW for the entire contingency amount.

First Pass – ISO-NE is provided 350 MW of assistance. These shares are allocated equally, 117 MW each, among the other three participants.

Second Pass – NYISO is provided 350 MW of assistance. These shares are allocated equally, 117 MW each, among the other three participants.

Third Pass –PJM is provided 350 MW of assistance. These shares are allocated equally, 117 MW each, among the other three participants.

Total Generation Picked up – The additional generation in each Balancing Authority after all Balancing Authorities provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Balancing Authority returns it ACE to zero is shown in the last column.

The table below summarizes the changes in schedule and ACE from just prior to the contingency, through the cancellation of assistance and full recovery by both Balancing Authorities losing energy due to the contingency. In practice, the SAR Coordinator merges the negation of the initial schedules (third row of numeric data) and the SAR

share entries (fourth row of numeric data) into a single step to promote timely implementation, achieving the same desired net effect. Note that the ACE in step 4 matches the **Total Generation Picked Up When SAR Energy Is Supplied Fully** column in the previous table, but is opposite in sign.

Time	IESO Sch	IESO ACE	NE Sch	NE ACE	PJM Sch	PJM ACE	NY Sch	NY ACE	Tot Sch	Tot ACE
Pre-contingency	0	0	+1400	0	-700	0	-700	0	0	0
Contingency	0	0	+1400	-2100	-700	0	-700	0	0	-2100
Negation of PJM/NY/NE schedules	0	0	0	-700	0	-700	0	-700	0	-2100
No response, SAR entries	+350	-350	-117	-583	-117	-583	-117	-583	0	-2100
Full response, SAR not canceled	+350	0	-117	0	-117	0	-117	0	0	0
SAR just canceled	0	+350	0	-117	0	-117	0	-117	0	0
All get back to ACE = 0	0	0	0	0	0	0	0	0	0	0

In the table above, NE Sch represents the sum of the energy exports wheeled from HQTE through ISO-NE to NYISO and PJM. PJM Sch represents the energy being wheeled from HQTE through ISO-NE and NYISO for PJM. NY Sch represents the energy being wheeled from HQTE through ISO-NE for NYISO.

Note that IESO, ISO-NE, and NBSO model their HVDC radial tie line imports as an internal generator, and their ACE will immediately reflect the loss of resource. NYISO includes HQTE HVDC interchange schedules within its AGC system, so NYISO must set that schedule to zero as soon as possible so its ACE reflects the loss of resource.

Radial Source Contingencies With Counter flow Transactions

Example 5. Counter flow Transactions on MSC 7040
PJM Exports 400 MW to HQTE on MSC 7040, NYISO Imports 1200 MW:

MSC 7040 flow =	800 MW
HQTE – NYISO transaction =	1200 MW
HQTE – PJM transaction =	-400 MW (flow is PJM to HQTE)

Area	**Initial Share/ Assistance Sought**	**First Pass**	**Second Pass**	**Total Generation Picked Up When SAR Energy Is Supplied Fully**	**Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0**
IESO		200	-67	133	0
ISO-NE		200	-67	133	0
NYISO	600		-67	533	1200
PJM	-200	200		0	-400
Sum	400	600	-200	800	800

Initial Shares – NYISO and PJM are initially assigned one half of their respective energy import from and energy export to HQTE. Consequently, under the ordinary SAR rules, they would be 'seeking' assistance for both flows into and out of Québec. The total net assistance sought is 400 MW for the net contingency amount.

First Pass – NYISO is provided 600 MW of assistance. These shares are allocated equally, 200 MW each, among the other three participants – including PJM.

Second Pass – PJM is provided -200 MW of assistance. These shares are allocated equally, -67 MW each, among the other three participants – including NYISO. These negative shares reduce the net pick-ups required of the assisting Balancing Authorities**.**

Total Generation Picked up – The additional generation in each Balancing Authority**,** after all Balancing Authorities provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Balancing Authority returns it ACE to zero is shown in the last column.

The table below summarizes the changes in schedule and ACE from just prior to the contingency, through the cancellation of assistance and full recovery by both Balancing Authorities losing energy due to the. In practice, the SAR Coordinator merges the negation of the initial schedule (third row of numeric data) and the SAR share entries (fourth row of numeric data) into a single step to promote timely implementation, achieving the same desired net effect. Note that the ACE in step 4 matches the **Total Generation Picked Up When SAR Energy Is Supplied Fully** column in the previous table, but is opposite in sign.

Time	IESO Sch	IESO ACE	NE Sch	NE ACE	PJM/ NY Sch	PJM ACE	PJM/ NY Sch	NY ACE	Tot Sch	Tot ACE
Pre-contingency	0	0	0	0	+400	0	-400	0	0	0
Contingency	0	0	0	0	+400	0	-400	-800	0	-800
Negation of PJM/NY schedule	0	0	0	0	0	+400	0	-1200	0	-800
No response, SAR entries	+133	-133	+133	-133	+200 +200 =400	0	-600-67 =-667	-533	0	-800
Full response, SAR not canceled	+133	0	+133	0	400	0	-667	0	0	0
SAR just canceled	0	+133	0	+133	0	+400	0	-667	0	0
All get back to ACE = 0	0	0	0	0	0	0	0	0	0	0

Note that IESO, ISO-NE, and NBSO model their HVDC radial tie line imports as an internal generator, and their ACE will immediately reflect the loss of resource. NYISO includes HQTE HVDC interchange schedules within its AGC system, so NYISO must set that schedule to zero as soon as possible so its ACE reflects the loss of resource.

Example 6. ISO-NE imports 2000 MW from HQTE, PJM and NYISO export 500 MW each to Québec on Sandy Pond:

Sandy Pond flow =	1000 MW
NYISO - HQTE transaction =	-500 MW (flow is NY to HQTE)
HQTE – ISONE transaction =	2000 MW
PJM – HQTE transaction =	-500 MW (flow is PJM to HQTE)

Area	**Initial Share/ Assistance Sought**	**First Pass**	**Second Pass**	**Third Pass**	**Total Generation Picked Up When SAR Energy Is Supplied Fully**	**Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0**
IESO		333	-83	-83	167	0
ISO-NE	1000		-83	-83	834	2000
NYISO	-250	333		-83	0	-500
PJM	-250	333	-83		0	-500
Sum	500	1000	-250	-250	1000	1000

Initial Shares – ISO-NE, NYISO and PJM are initially assigned one half of their respective energy imports from and energy exports to Québec. Consequently, under the ordinary SAR rules, they would be 'seeking' assistance for flows into and out of Québec. The total assistance sought is 500 MW for the net contingency amount.

First Pass – ISO-NE is provided 1000 MW of assistance. These shares are allocated equally, 333 MW each, among the other three participants.

Second Pass – NYISO is provided -250 MW of assistance. These shares are allocated equally, -83 MW each, among the other three participants.

Third Pass –PJM is provided -250 MW of assistance. These shares are allocated equally, -83 MW each, among the other three participants.

Total Generation Picked up – The additional generation in each Balancing Authority after all Balancing Authorities provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Balancing Authority returns its ACE to zero is shown in the last column.

The table below summarizes the changes in schedule and ACE from just prior to the contingency, through the cancellation of assistance and full recovery by both Balancing Authorities losing energy due to the contingency. In practice, the SAR Coordinator merges the negation of the initial schedules (third row of numeric data) and the SAR share entries (fourth

row of numeric data) into a single step to promote timely implementation, achieving the same desired net effect. Note that the ACE in step 4 matches the **Total Generation Picked Up When SAR Energy Is Supplied Fully** column in the previous table, but is opposite in sign.

Time	**IESO Sch**	**IESO ACE**	**NE Sch**	**NE ACE**	**PJM Sch**	**PJM ACE**	**NY Sch**	**NY ACE**	**Tot Sch**	**Tot ACE**
Pre-contingency	0	0	-1000	0	+500	0	+500	0	0	0
Contingency	0	0	-1000	-1000	+500	0	+500	0	0	-1000
Negation of NE PJM/NY schedules	0	0	0	-2000	0	+500	0	+500	0	-1000
No response, SAR entries	+167	-167	-1000-83-83 = -1166	-834	+250 +333-83 =500	0	+250 +333-83 =500	0	0	-1000
Full response, SAR not canceled	+167	0	-1166	0	500	0	500	0	0	0
SAR just canceled	0	+167	0	-1166	0	+500	0	+500	0	0
All get back to ACE = 0	0	0	0	0	0	0	0	0	0	0

In the table above, NE Sch represents the sum of the energy exports wheeled from PJM and NYISO through ISO-NE to HQTE. PJM Sch represents the energy being wheeled to HQTE through ISO-NE and NYISO for PJM. NY Sch represents the energy being wheeled to HQTE through ISO-NE for NYISO.

Note that IESO, ISO-NE, and NBSO model their HVDC radial tie line imports as an internal generator, and their ACE will immediately reflect the loss of resource. NYISO includes HQTE HVDC interchange schedules within its AGC system, so NYISO must set that schedule to zero as soon as possible so its ACE reflects the loss of resource.

Appendix 5 - NPCC Control Performance Reporting Process

Reporting Processes

a. Each Balancing Authority not receiving overlap regulation service determines their CPS 1 and CPS 2 scores for the recently completed month by the tenth day after the end of the month.
b. Each Balancing Authority's NPCC CO-1 member (or his/her designee) collects and reviews the CPS1 and CPS 2 results for accuracy.
c. Each Balancing Authority's NPCC CO-1 member (or his/her designee) sends their CPS results to the appropriate NPCC compliance monitoring personnel.
d. The NPCC CO-1 Chair (or his/her designee) summarizes recent CPS 1 and CPS 2 performance in a running annual summary.
e. The NPCC CO-1 Chair (or his/her designee) informs TFCO when a substantive change in performance has occurred for any NPCC Balancing Authority that reports CPS 1 and CPS 2 compliance.
f. NPCC CO-1 has primary responsibility for monitoring the control performance of the NPCC region.

Appendix 6 Light Load Conditions

Relatively large quantities of excess generation within a Balancing Area occurring during light load conditions may affect reliability adversely, and will cause actual interchange to deviate from scheduled interchange. Guidance to alleviate possibly adverse impacts on reliability and to lessen actual interchange deviations from schedule is provided in this appendix. A Balancing Authority that is anticipating or actually experiencing a Light Load Condition should consider implementing any of the following actions that are applicable and can lessen the adverse impacts noted above:

1. Adjust interchange schedules to reduce the import and/or increase the export of energy.
2. If permitted by operating policies, increase load by scheduling available pumped storage facilities in the pumping mode.
3. Arrange for bilateral inadvertent payback to increase the export of energy.
4. If permitted by operating policies, request that an appropriate amount of supply-side **resources** be reduced to the absolute minimum.
5. Review all supply-side **resource** "must-run" requirements. Determine if any may be temporarily removed or if other supply-side **resources** with lower limits could be brought on in place of normal "must-run" supply-side **resources**.
6. Review all supply-side **resource** "low-limits" and temporarily reduce them as low as possible.
7. De-commit sufficient ge**neration** to alleviate or minimize the excess generation condition.

Appendix 7 – Participation Request Form

Instructions

NPCC Balancing Authorities and adjacent Balancing Authorities must complete this form to request participation in the following NPCC Programs:

- Simultaneous Activation of Reserve (SAR)
- Ace Diversity Interchange (ADI)
- Regional Reserve Deficiency

This form must be completed in full and submitted to the NPCC Task Force on Coordination of Operation (TFCO) for review and approval. The form must be authorized by an officer of the company submitting the form. On review of the form, the TFCO will notify the submitting Balancing Authority of the programs that they are approved to participate in.

The Coordinator role for all programs must also be approved by the TFCO.

Participation Request Form

Balancing Authority Name: _____

The Balancing Authority named above requests participation in the following programs (check one or more):

Simultaneous Activation of Reserve: ☐

Ace Diversity Interchange: ☐

Regional Reserve Deficiency ☐

The Balancing Authority named above wishes to act as the coordinator for:

Coordinator: (SAR) ☐

Coordinator: (ADI) ☐

Coordinator:
Regional Reserve Deficiency ☐

The undersigned must be an officer of the Balancing Authority named above with the authority to authorize participation by their company.

Name: _____

Title: _____

Signature: _____

Date: _____

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1515 BROADWAY, NEW YORK, NY 10036-8901 TELEPHONE: (212) 840-1070 FAX (212) 302-2782

NPCC
Regional Reliability Reference Directory # 7
Special Protection Systems

Task Force on System Protection Revision Review Record
December 27, 2007

Adopted by the Members of the Northeast Power Coordinating Council Inc., this December 27, 2007, based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 and as amended to date.

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Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	12/27/07		New

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Introduction

1.1 Title Special Protection Systems

1.2 Directory Number 7

1.3 Objective

Provide the basic criteria for **Special Protection Systems** such that the **Bulk Power System** in NPCC Inc. member **Areas** is operated reliably.

1.4 Effective Date Immediately upon Approval by the NPCC Full Members

1.5 Background

This directory establishes the basic **protection** criteria for **Special Protection Systems**. It is not intended to be a design specification. It is recognized that responsible entities in certain **Areas** may choose to apply more rigid criteria because of local considerations.

Guidance for consideration in the implementation of these criteria is provided in Appendix A, and the procedure for reviewing new and revised **Special Protection Systems** is provided in Appendix B.

1.6 Applicability

1.6.1 Functional Entities

Transmission Owner, Generator Owner, Distribution Provider

1.6.2 Facilities

1.6.2.1 New Facilities

The standard requirements and criteria stipulated in this Directory apply to all new Type I and Type II **Special Protection Systems** (SPSs) as defined below. In the application of Type II SPSs, their security is the prime concern (see Section 3.3.1 of this document). As such, Sections 3.3.1.1, 3.3.2.3, 3.3.3.2, 3.3.6 and 3.3.8.1 in this document do not apply to Type II.

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1.6.2.2 Existing Facilities

It is the responsibility of individual Transmission Owners (TO), Generator Owners (GO) and Distribution Providers (DP) to assess their existing **Special Protection Systems** and to make modifications which are required to meet the intent of these standards as follows:

a. Planned Renewal or Upgrade to Existing Facilities It is recognized that there may be **SPSs,** which existed prior to each TO's, GO's and DP's adoption of the *Special Protection System Criteria* that do not meet these criteria. If any **Special Protection Systems** or sub-systems of these facilities are replaced as part of a planned renewal or upgrade to the facility and do not meet all of these criteria, then an assessment shall be conducted for those criteria that are not met. The result of this assessment shall be reported on TFSP Form #1-5.

b. SPS Re-classified to Type I or Type II

These requirements apply to all existing SPSs which are reclassified as Type I or Type II due to system changes. A mitigation plan shall be required to bring such a SPS into compliance with these criteria.

c. In-kind Replacement of SPS Equipment

If SPS equipment is replaced "in-kind" as a result of an un-planned event, then it is not required to upgrade the associated protection system to comply with these criteria.

1.6.3 Classification of **Special Protection Systems**

Special Protection Systems are sub-divided into three types. Reference can be made to the NPCC *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2) where design criteria contingencies are described in Section 5.0; operating criteria contingencies, in Section 6.0; and extreme contingencies, in Section 7.0 of Document A-2.

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Type I	A **Special Protection System** which recognizes or anticipates abnormal system conditions resulting from design and operating criteria **contingencies**, and whose misoperation or failure to operate would have a **significant adverse impact** outside of the local area. The corrective action taken by the **Special Protection System** along with the actions taken by other **protection systems** are intended to return power system parameters to a stable and recoverable state.
Type II	A **Special Protection System** which recognizes or anticipates abnormal system conditions resulting from extreme **contingencies** or other extreme causes, and whose misoperation or failure to operate would have a **significant adverse impact** outside of the local area.
Type III	**Special Protection System** whose misoperation or failure to operate results in no **significant adverse impact** outside the local area. The practices contained in this document for a Type I SPS should be considered but are not required for a Type III SPS. It should be recognized that a Type III SPS may, due to system changes, become Type I or Type II.

2.0 Terms Defined in this Directory

The following terms are defined in this Directory. Their definitions are provided in Attachment 1.

Bulk Power System
Contingency
Fault
Operating Procedures
Protection
Special Protection System (SPS)
Teleprotection

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3.0 Requirements

3.1 The NERC ERO Reliability Standards containing Requirements that are associated with this Directory include, but may not be limited to:

3.1.1 PRC-012-0 — Special Protection System Review Procedure

3.1.2 PRC-013-0 Special Protection System Database

3.1.3 PRC-014-0 — Special Protection System Assessment

3.1.4 PRC-015-0 — Special Protection System Data and Documentation

3.1.5 PRC-016-0 — Special Protection System Misoperations

3.1.6 PRC-017-0 - Special Protection System Maintenance and Testing

3.2 NPCC Regional Reliability Standard Requirements

None at this time. To be developed.

3.3 NPCC "Full Member", More Stringent Criteria

3.3.1 General Criteria

A **Special Protection System** shall be designed to recognize or anticipate the specific power system conditions associated with the intended function.

Due consideration shall be given to dependability and security. The relative effect on the **bulk power system** of a failure of an SPS to operate when desired versus an unintended operation shall be weighed carefully in selecting design parameters as follows:

3.3.1.1 To enhance dependability, a **Special Protection System** shall be designed with sufficient redundancy such that the **Special Protection System** is capable of performing its intended function while itself experiencing a single failure.

3.3.1.2 Multiple protection groups that are used to obtain redundancy within a **Special Protection System** shall not share the same component.

3.3.1.3 A **Special Protection System** shall be designed to avoid false operation while itself experiencing a credible failure.

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3.3.1.4 The thermal capability of all **Special Protection System** components shall be adequate to withstand the maximum short time and continuous loading conditions to which the associated power system elements may be subjected.

3.3.1.5 Communication link availability, critical control switch and test switch positions, and trip circuit integrity, shall be monitored to allow prompt attention by appropriate operating authorities.

3.3.1.6 When remote access to **Special Protection Systems** is possible, the design shall include security measures to minimize the probability of unauthorized access to the **Special Protection System**.

3.3.1.7 An SPS shall be designed to take corrective action within times determined by studies with due regard to security, dependability and selectivity.

3.3.1.8 Status of SPS arming shall be monitored to allow prompt attention by appropriate operating authorities.

3.3.1.9 An SPS shall be equipped with means to enable its arming and to independently verify the arming.

3.3.2 Current Transformer Criteria

Current transformers (CTs) associated with **Special Protection Systems** shall have adequate steady-state and transient characteristics for their intended function.

3.3.2.1 The output of each current transformer secondary winding shall be designed to remain within acceptable limits for the connected burdens under all anticipated currents, including **fault** currents, to ensure correct operation of the **Special Protection System**.

3.3.2.2 The thermal and mechanical capabilities of the CT at the operating tap shall be adequate to prevent damage under maximum **fault** conditions and normal or **emergency** system loading conditions.

3.3.2.3 For **protection groups** to be independent, they shall be supplied from separate current transformer secondary windings.

3.3.2.4 Interconnected current transformer secondary wiring shall be grounded at only one point.

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3.3.3 Voltage Transformer and Potential Device Criteria

Voltage transformers and potential devices associated with **Special Protection Systems** shall have adequate steady-state and transient characteristics for their intended functions.

3.3.3.1 Voltage transformers and potential devices shall have adequate volt-ampere capacity to supply the connected burden while maintaining their **relay** accuracy over their specified primary voltage range.

3.3.3.2 If a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, each of the **protection groups** shall be supplied from separate voltage sources. The **protection groups** may be supplied from separate secondary windings on one transformer or potential device, provided all of the following requirements are met:

. Complete loss of one or more phase voltages does not prevent operation of both SPS protection groups;
. Each secondary winding has sufficient capacity to permit fuse **protection** of the circuit;
. Each secondary winding circuit is adequately fuse protected.

3.3.3.3 The wiring from each voltage transformer secondary winding shall not be grounded at more than one point.

3.3.3.4 Voltage transformer installations should be designed with due regard to ferroresonance.

3.3.4 Battery and Direct Current (dc) Supply Criteria

dc supplies associated with a **Special Protection System** shall be designed to have a high degree of dependability as follows.

3.3.4.1 If a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, no single battery or dc power supply failure shall prevent the independent **protection groups** from performing the intended function. Each battery shall be provided with its own charger.

3.3.4.2 Each battery shall have sufficient capacity to permit operation of the **Special Protection System**, in the event of a loss of its battery charger or the ac supply source, for the period of time necessary to transfer the load to

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the other battery or re-establish the supply source.

3.3.4.3 The battery chargers and all dc circuits shall be protected against short circuits. All protective devices should be coordinated to minimize the number of dc circuits interrupted.

3.3.4.4 dc battery systems shall be continuously monitored to detect abnormal voltage levels (both high and low), dc grounds, and loss of ac to the battery chargers in order to allow prompt attention by the appropriate operating authorities.

3.3.4.5 **Special Protection System** dc supply circuits shall be continuously monitored to detect loss of voltage in order to allow prompt attention by the appropriate operating authorities.

3.3.5 Station Service ac Supply Criteria

If a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, there shall be two sources of station service ac supply, each capable of carrying at least all the critical loads associated with the **Special Protection System**.

3.3.6 Circuit Breakers Criteria

Where **Special Protection System** redundancy is achieved by use of independent **protection groups** tripping the same circuit breakers without overarming, each circuit breaker shall be equipped with two independent trip coils.

3.3.7 Teleprotection Criteria

Communication facilities required for **teleprotection** shall be designed to have a level of performance consistent with that required of the **Special Protection System**, and shall meet the following:

3.3.7.1 Where the design of a **Special Protection System** is composed of multiple **protection groups** for redundancy and each group requires a communication channel, the equipment and channel for each group shall be separated physically and designed to minimize the risk of more than one **protection group** being disabled simultaneously by a single event or condition.

3.3.7.2 **Teleprotection** equipment shall be monitored to detect loss of equipment and/or channel to allow prompt attention by the appropriate operating authorities.

3.3.7.3 **Teleprotection** systems shall be designed to assure adequate signal transmission

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during **bulk power system** disturbances, and shall be provided with means to test for proper signal adequacy.

3.3.7.4 **Teleprotection** equipment shall be powered by the substation batteries or other sources independent from the power system.

3.3.7.5 Except as identified otherwise in these criteria, the two **teleprotection** groups shall not share the same component. The use of a single communication tower for the radio communication systems used by the two SPS groups is permitted.

3.3.8 Physical Separation/Environment Criteria

3.3.8.1 In addition to the physical separation as referenced in sections 3.3.1.2 and 3.3.9.5, if a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, each separate protection group and **Teleprotection** of an SPS shall be on different non-adjacent vertical mounting assemblies or enclosures.

3.3.8.2 In the event a common raceway is used, cabling for separate groups of an SPS shall be separated by a fire barrier.

3.3.9 Grounding Criteria

Station grounding is critical to the correct operation of **Special Protection Systems**. The design of the ground grid directly impacts proper **Special Protection System** operation and probability of false operation from **fault** currents or transient voltages.

3.3.9.1 Each TO, GO and DP shall have established as part of its substation design procedures or specifications, a mandatory method of designing the substation ground grid, which:

. Can be traced to a recognized calculation methodology
. Considers cable shielding
. Considers equipment grounding

3.3.10 Provision for Breaker Failure Criteria

Type I SPS shall include breaker failure **protection** for each circuit breaker whose operation is critical to the adequacy of the action taken by the SPS with due regard to the power system conditions this SPS is required to detect. Options for breaker failure **protection**:

3.3.10.1 A design which recognizes that the breaker has not achieved or will not achieve the

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intended function required by the **Special Protection System** and which takes independent action to achieve that function. This provision needs not be duplicated and can be combined with conventional breaker failure schemes if appropriate.

3.3.10.2 Overarming the **Special Protection System** such that adequate action is taken even if a single breaker fails.

3.3.10.3 The redundancy afforded by actions taken by other independent schemes or devices.

3.3.11 Testing and Maintenance Criteria

3.3.11.1 Each SPS shall be maintained in accordance with the Maintenance Criteria for Bulk Power System Protection (Document A-4).

3.3.11.2 The design of an SPS both in terms of circuitry and physical arrangement shall facilitate periodic testing and maintenance.

3.3.11.3 Test facilities or test procedures shall be designed such that they do not compromise the independence of the redundant design aspects of the SPS.

3.3.11.4 An SPS shall be functionally tested when initially placed in service and when modifications are made.

3.3.11.5 If a segmented testing approach is used, test procedures and test facilities shall be designed to ensure that related tests properly overlap. Proper overlap is ensured if each portion of circuitry is seen to perform its intended function, such as operating a relay, from either a real or test stimulus, while observing some common reliable downstream indicator.

3.3.11.6 All positive combinations of input logic shall be tested regardless of the maintenance strategy used.

3.3.11.7 Sufficient testing shall be employed to ensure that timing races do not exist within hardwired or electronic logic, and that the SPS operating time is within design limits.

3.3.11.8 Each time the SPS is maintained, its hardware shall be tested in conjunction with the control facilities, related computer equipment, software and **operating procedures** to ensure compatibility and correct operation.

3.3.12 Analysis of SPS Performance

3.3.12.1 **Bulk power system** automatic operations shall be analyzed to determine proper **Special Protection System** performance. Corrective measures must be taken promptly if the **Special Protection System** or a **protection group** within the SPS fails to operate or operates incorrectly.

3.3.12.2 Event recording capability shall be provided to permit analysis of system operations and **Special Protection System** performance.

4.0 Measures and Assessments

None developed at this time.

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Prepared by:	Lead Task Force- Task Force on System Protection
Review and Approval:	Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC Inc. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as Links, Glossary Terms, etc., will only require RCC Member approval of the document. Errata may be corrected by the Lead Task Force at any time and provide the appropriate notifications to the NPCC Inc. membership. This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC Regional Reliability Standards and other NPCC documents.
References:	NPCC RRS PRC-XXX-X (Future NPCC Regional Standard) Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2) Emergency Operation Criteria (Document A-3) Maintenance Criteria for Bulk Power System Protection (Document A-4) NPCC Glossary of Terms (Document A-7)

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Attachment 1
Definition of Terms

Bulk power system - The interconnected electrical systems within northeastern North America comprising **generation** and transmission facilities on which **faults** or **disturbances** can have a **significant adverse impact** outside of the local area. In this context, local areas are determined by the Council members.

Contingency – An event, usually involving the loss of one or more **elements,** which affects the **power** system at least momentarily.

Fault – An electrical short circuit.

Permanent Fault — A fault which prevents the affected **element** from being returned to service until physical actions are taken to effect repairs or to remove the cause of the fault.

Transient Fault — A fault which occurs for a short or limited time, or which disappears when the faulted **element** is separated from all electrical sources and which does not require repairs to be made before the **element** can be returned to service either manually or automatically.

Operating Procedures -A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.

Automatic Operating Systems — **Special protection systems**, remedial action schemes, or other operating systems installed on the electric systems that require *no intervention* on the part of **system operators**.

Normal (Precontingency) Operating Procedures — Operating procedures that are normally invoked by the **system operator** to alleviate potential facility overloads or other potential system problems in anticipation of a **contingency**.

Postcontingency Operating Procedures — Operating procedures that may be invoked by the **system operator** to mitigate or alleviate system problems after a **contingency** has occurred.

Protection -The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.

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Protection group — A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups.

Notes:

(a) Variously identified as Main **Protection**, Primary **Protection**, Breaker Failure **Protection**, Back-Up **Protection**, Alternate **Protection**, Secondary **Protection**, A **Protection**, B **Protection**, Group A, Group B, System 1 or System 2.

(b) Pilot **protection** is considered to be one **protection group.**

Protection system

Element Basis

One or more **protection** groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete **protection** of that **element**.

Terminal Basis

One or more **protection** groups, as above, installed at one terminal of a power system **element**, typically a transmission line.

Pilot **Protection** — A form of line **protection** that uses a communication channel as a means to compare electrical conditions at the terminals of a line.

Significant adverse impact — With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from **faults** or **disturbances**, shall be deemed as having **significant adverse impact**:

a. instability;
- any instability that cannot be demonstrably contained to a well defined local area.
- any loss of synchronism of generators that cannot be demonstrably contained to a well-defined local area

b. unacceptable system dynamic response;
- an oscillatory response to a **contingency** that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event.

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c. unacceptable equipment tripping
   - tripping of an un-faulted **bulk power system** element (element that has already been classified as **bulk power system**) under planned system configuration due to operation of a **protection** system in response to a stable power swing
   - operation of a Type I or Type II **Special Protection System** in response to a condition for which its operation is not required

d. voltage levels in violation of applicable **emergency** limits;

e. loadings on transmission facilities in violation of applicable **emergency** limits;

Special protection system (SPS) – A **protection system** designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted **elements**. Such action may include changes in **load**, **generation**, or system configuration to maintain system **stability**, acceptable voltages or power flows. Automatic underfrequency **load shedding** as defined in the *Emergency Operation Criteria* A-3, is not considered a **Special Protection System**. Conventionally switched, locally controlled shunt devices are not **Special Protection Systems**.

Teleprotection - A form of **protection** that uses a communication channel

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Appendix A
Guidance for Consideration in SPS Design

Introduction

This Appendix provides the guidance for consideration in the implementation of the **Special Protection System** design criteria stipulated in Section 3.3 of this Directory.

The general objective for any SPS is to perform its intended function (generator rejection, load rejection, etc.) in a dependable and secure manner. In this context, dependability relates to the degree of certainty that the SPS will operate correctly when required to operate. Security relates to the degree of certainty that the SPS will not operate when not required to operate.

The relative effects on the **bulk power system** of a failure to operate when desired versus an unintended operation should be weighed carefully in selecting design parameters. For example, the choice of duplication as a means of providing redundancy improves the dependability of the SPS but can also jeopardize security in that it may increase the probability of an unintended operation. This general objective can be met only if the SPS can dependably respond to the specific conditions for which it is intended to operate and differentiate these from other conditions for which action must not take place.

Close coordination should be maintained among system planning, design, operating, maintenance and **protection** functions, since both initially and throughout their life cycle, SPSs are a multi-discipline concern.

2.0 Considerations Affecting Dependability

2.1 Redundancy is normally provided by duplication. Some aspects of duplication may be achieved by overarming, which is defined as providing for more corrective action than would be necessary if no failures are considered. The redundancy requirements for an SPS apply only with respect to its response to the conditions it is required to detect.

2.2 For a **Special Protection System** that is composed of multiple **protection groups**, the risk of simultaneous failure of more than one **protection group** because of design deficiencies or equipment failure should be considered, particularly if identical equipment is used in each **protection group**. The extent and nature of these failures should be recognized in the design and operation of the **Special Protection System.**

2.3 Area of common exposure should be kept to a minimum to reduce the possibility of all groups being disabled by a single event such as fire, evacuation, water leakage, and other such incidents.

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3.0 Considerations Affecting Security

3.1 An SPS should be designed to operate only for conditions which require its specific protective or control actions.

3.2 **Special Protection Systems** should be no more complex than required for any given application.

3.3 The components and software used in **Special Protection Systems** should be of proven quality, as demonstrated either by actual experience or by stringent tests under simulated operating conditions.

3.4 **Special Protection Systems** should be designed to minimize the possibility of component failure or malfunction due to electrical transients and interference or external effects such as vibration, shock and temperature

3.5 **Special Protection Systems**, including intelligent electronic devices (IEDs) and communication systems used for **protection**, should comply with applicable industry standards for utility grade **protection** service. Utility Grade **Protection** System Equipment are equipment that are suitable for protecting transmission power system elements, that are required to operate reliably, under harsh environments normally found at substations. Utility grade equipment should meet the applicable sections of all or some of the following types of industry standards, to ensure their suitability for such applications:

- IEEE C37.90.1-2002 (oscillatory surge and fast transient)
- IEEE C37.90.1-2002 (service conditions)
- IEC 60255-22-1, 2005 (1 MHz burst, i.e. oscillatory)
- IEC 61000-4-12, 2001 (oscillatory surge)
- IEC 61000-4-4, 2004 (EFT)
- IEC 60255-22-4, 2002 (EFT)
- IEEE C37.90.2-2004 (narrow-band radiation)
- IEC 60255-22-3, 2000 (narrow-band radiation)
- IEC 61000-4-3, 2002 (narrow-band radiation)
- IEEE 1613 (communications networking devices in Electric power Substations)

3.6 **Special Protection System** circuitry and physical arrangements should be carefully designed so as to minimize the possibility of incorrect operations due to personnel error.

3.7 **Special Protection System** automatic self-checking facilities should be designed so as to not degrade the performance of the **Special Protection System**.

3.8 Consideration should be given to the consequences of loss of instrument transformer voltage inputs to **Special Protection Systems**.

3.9 Consideration should be given to the effect of the means of arming on overall security and dependability of the **Special Protection System**. Arming should have a level of security and dependability commensurate with the requirements of the SPS.

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4.0 Considerations Affecting Performance

4.1 Control Cable, Wiring and Ancillary Control Device

Control cables and wiring and ancillary control devices should be highly dependable and secure. Due consideration should be given to published codes and standards, fire hazards, current-carrying capacity, voltage drop, insulation level, mechanical strength, routing, shielding, grounding and environment.

4.2 Environment

Means should be employed to maintain environmental conditions that are favorable to the correct performance of **Special Protection Systems.**

5.0 Operating Time of an SPS

Adequate time margin should be provided taking into account study inaccuracies, differences in equipment, and **protection** operating times.

6.0 Arming of an SPS

Arming is the selection, which may be external to the **Special Protection System**, of desired output action based on power system conditions and recognized contingencies. Arming requirements of a Special Protection System are normally based upon the results of system studies which take into account recognized contingencies, operating policies/procedures and current power system load/generation conditions. For a simple **Special Protection System**, arming may be an on/off function. A **Special Protection System** can be armed either automatically or manually.

6.1 Automatic arming is implemented without human intervention.

6.2 Arming manually if the recognition, decision or implementation requires human intervention. Sufficient time with adequate margin for recognition, analysis and the taking of corrective action should be allowed.

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7.0 Maintenance Considerations

7.1 Additional periodic maintenance is recommended on the following **protection** equipment:

- On continuously monitored analog **teleprotection** channels, verify signal adequacy every twelve months.
- On non-monitored analog **teleprotection** channels, verify signal adequacy every month.
- On digital **teleprotection** systems, which are inherently monitored, verify local function every two years.
- On batteries and chargers, verify proper operation and general condition every month.
- On circuit breakers, verify ability to trip via each trip coil every two years, with due regard to critical trip paths between sensing relays and the breaker trip coils.

7.2 It is the responsibility of each TO, GO and DP to evaluate its own particular circumstances and determine if any additional maintenance should be performed on its system. More extensive maintenance may be required but not limited to:

- during the initial break-in period,
- where **protection** systems are exposed to abnormal conditions such as temperature extremes, vibration, corrosive atmosphere, etc.,
- when the operating condition of **protection** system control wiring is suspect..

7.3 The design of a **Special Protection System** both in terms of circuitry and physical arrangement should facilitate periodic testing and maintenance in a manner that mitigates the risk of inadvertent operation. As a **Special Protection System** may be complex and may interface with other protection systems or control systems, special attention should be placed on ensuring that test devices and test interfaces properly support a clearly defined maintenance strategy.

7.4 Proper overlap is ensured if each portion of circuitry is seen to perform its intended function, such as operating a relay, from either a real or test stimulus, while observing some common reliable downstream indicator.

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7.5 Whenever practicable, some of the maintenance testing requirements may be met by analyzing and documenting the detailed performance of the **Special Protection System** during actual events to demonstrate that the specific testing requirements have been fulfilled. Such an approach can reduce the probability of false operation during maintenance while effectively reducing the extent of planned maintenance.

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Appendix B
Procedure for Review of Special Protection Systems

Introduction

This Appendix provide the procedure to follow to obtain concurrence from NPCC if an entity concludes that a new **Special Protection System** or a modification of an existing **Special Protection System** will be required which affects the **bulk power system**. The procedure is also shown on the attached flow chart.

2.0 NPCC Review and Concurrence

2.1 Allowing for sufficient lead time to ensure an orderly review, the entity will notify the chairman of the Task Force on Coordination of Planning (TFCP) of its proposal to install a new **Special Protection System** or modify an existing **Special Protection System**. The entity will send copies of the complete notification to TFCO and TFSP. This notification will include statements that describe possible failure modes and whether misoperation, unintended operation or failure of the **Special Protection System** would have local, inter-company, inter-**Area** or inter-Regional consequences, when the **Special Protection System** is planned for service, how long it is expected to remain in service, the specific **contingency**(s) for which it is designed to operate and whether the **Special Protection System** will be designed according to the NPCC *Bulk Power System Protection Criteria* (Document A-5) and the *Special Protection System Criteria* and Standards requirements listed in this docment.

2.2 If the **Special Protection System** is expected to have only local consequences, TFCP will request that the Task Force on System Studies (TFSS) and the Task Force on System Protection (TFSP) review the proposal.

2.2.1 TFSP will be notified of the proposed **Special Protection System**. TFSP will advise TFCP of any concerns.

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2.2.2 TFSS will review the analyses that the proposing entity has performed. A presentation may be required from the proposing entity. The purpose of the review will be to confirm that there are no adverse inter-**Area** or inter-Regional consequences of either a failure of the **Special Protection System** to operate when and how it is required or an inadvertent or unintended operation of the **Special Protection System**. If necessary, TFSS will request that the proposing entity conduct additional analyses.

2.2.3 If the TFSS review confirms the **Special Protection System** has only local consequences, TFSS will send the information to TFCP. If TFCP concurs, they will then notify the proposing entity of NPCC's conclusions that the **Special Protection System** has only local consequences. TFCP will also notify the Reliability Coordinating Committee (RCC), all the Task Forces, the Compliance Committee (CC), the proposing entity and other Members that concurrence has been given to the proposing entity to modify an existing **Special Protection System** or install a new **Special Protection System**, at which time, the **Special Protection System** may be deployed.

2.2.4 If the TFSS review concludes that the **Special Protection System** could have inter-**Area** or inter-Regional consequences, they will inform the TFCP. Upon receipt of the TFSS conclusion or if TFCP separately determines the **Special Protection System** could have inter-**Area** or inter-Regional consequences, TFCP will arrange for an overall NPCC review as detailed in Step 3.

2.2.5 TFSS will update the NPCC **Special Protection System** list/database.

2.3 If the proposing entity expects the **Special Protection System** to have inter-**Area** or inter-Regional consequences, or if the TFSS or TFCP review concludes this to be the case, TFCP will request the Task Force on Coordination of Operation (TFCO), the Task Force on System Protection (TFSP) and TFSS to review it. Each of the Task Forces may require a presentation from the proposing entity.

2.3.1 TFSP will confirm the failure modes of the **Special Protection System**, including actions of back-up **protection**, and whether or not the **Special Protection System** complies with NPCC system **protection** standards. TFSP will review whether the new or modified **Special Protection System** is in conformance with the NPCC *Bulk Power System Protection Criteria* (Document A-5) and the *Special*

Protection System Criteria and Standards requirments listed in this document and forward a summary of their findings to TFCO, TFCP and TFSS. This summary will include a statement as to whether the **Special Protection System** is in conformance with the *Bulk Power System Protection Criteria* (Document A-5) and the *Special Protection System Criteria* and Standards requirments listed in this document and whether the Task Force has any objections to its modification or installation.

2.3.2 TFSS will review the analysis that the proposing entity has performed. The purpose of the review will be to assess the **Special Protection System** is in conformance with the *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2) and to determine the inter-**Area** or inter-Regional consequences of either a failure of the **Special Protection System** to operate when and how it is required or an inadvertent or unintended operation of the **Special Protection System**. If necessary, TFSS will request that the proposing entity conduct additional studies. When their review is completed, TFSS will forward a summary of their findings to TFCO, TFCP and TFSP. This summary will include a statement as to whether the **Special Protection System** is in conformance with the *Basic Criteria* (A-2) and whether the Task Force has any objections to its modification or installation.

2.3.3 TFCO will review the operability of the **Special Protection System** and forward a summary of their findings to TFCP, TFSS and TFSP. This summary will include a statement as to whether the Task Force has any objections to its modification or installation.

2.3.4 TFCP will prepare an overall summary for the RCC. This summary will include the findings of the other Task Forces and whether there are any objections to the modification of the existing **Special Protection System** or the installation of the new **Special Protection System** and as a minimum, include the following information:

. Function, i.e. GR-generation rejection etc.
. Identification
. Initiating condition
. Action(s) resulting
. Name of the **Special Protection System**, and owner, identification number
. Arming, i.e. percentage of time, system conditions for which it's needed, manual vs. automatic, etc.
. Reason for the installation
. Comments, explanations, such as "temporary until such time…"
. Company, owner
. SPS Number, drawn by NPCC staff
. Current Status, i.e. New, Changed or Removed
. Type Determination

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- Determinations of the Task Forces' analyses
- Consequences of operation, misoperation and failure to operate
- Approximate of load or generation rejected by **Special Protection System** operation
- Proposed date of deployment
- Proposed date of retirement/deactivation

2.3.5 The RCC will review the summary report and act on the proposal to modify an existing **Special Protection System** or install a new **Special Protection System**. The RCC may also remand the review of the **Special Protection System** back to the TFCP if further analyses are determined to be needed.

2.3.6 The TFCP will notify the RCC, all the Task Forces, the CC, the proposing entity and other Members of the outcome of the review. Upon NPCC approval of the type and compliance with Criteria, the **Special Protection System** may be deployed.

2.3.7 The TFSS will then update the NPCC **Special Protection System** list/database.

3.0 Presentation and Review of Special Protection Systems

Each new or modified Type I or Type II **Special Protection System** shall be reported to the Task Force on System Protection in accordance with the following presentation and review procedure.

3.1 A presentation will be made to the TFSP on new facilities or a modification to an existing facility when requested by an NPCC Member or the TFSP.

3.2 A presentation will be made to the TFSP when the design of the **protection** facility deviates from the *Bulk Power System Protection Criteria* (Document A-5).

3.3 A presentation will be made to the TFSP when an NPCC Member is in doubt as to whether a design meets the *Protection Criteria*.

3.4 Data Required for Presentation and Review of Proposed **Special Protection System:**

3.4.1 The TO, GO or DP will advise the TFSP of the basic design of the proposed system. The data will be supplied on the attached forms, accompanied by a geographical map, a one-line diagram of all affected areas, and the associated **protection** and control function diagrams. A physical layout of **protection** panels and batteries for the purpose of illustrating physical separation will also be included.

3.4.2 The proposed **protection** system will be explained with due emphasis on

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any special conditions or design restrictions existing on the particular power system:

3.5 Procedure for Presentation:

3.5.1 The TO, GO or DP will arrange to have a technical presentation made to the TFSP.

3.5.2 To facilitate scheduling, the chairman of the TFSP will be notified approximately four months prior to the desired date of presentation.

3.5.3 Copies of materials to be presented will be distributed to TFSP members 30 days prior to the date of the presentation.

3.6 Review by TFSP

The TFSP will review the material presented and develop a position statement concerning the proposed **protection** system. This statement will indicate one of the following:

3.6.1 The need for additional information to enable the TFSP to reach a decision.

3.6.2 Acceptance of the TO, GO or DP statement of conformance to the *Protection Criteria*.

3.6.3 Acceptance of the submitted proposal.

3.6.4 *Conditional acceptance of the submitted proposal.

3.6.5 *Rejection of the submitted proposal

* Position Statements to include an indication of areas of departure from the intent of the *protection criteria* and suggestions for modifications to bring the **protection** system into conformance with the NPCC criteria.

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3.6.6 The results of the TFSP review will be documented in the following manner.

. A position statement will be included in the minutes of the meeting at which the proposed **protection** system was reviewed.

. If necessary, a letter outlining areas of nonconformance with the NPCC *Protection Criteria* and recommendations for correction will be submitted to the TO, GO or DP.

. The Task Force will maintain a record of all the reviews it has conducted.

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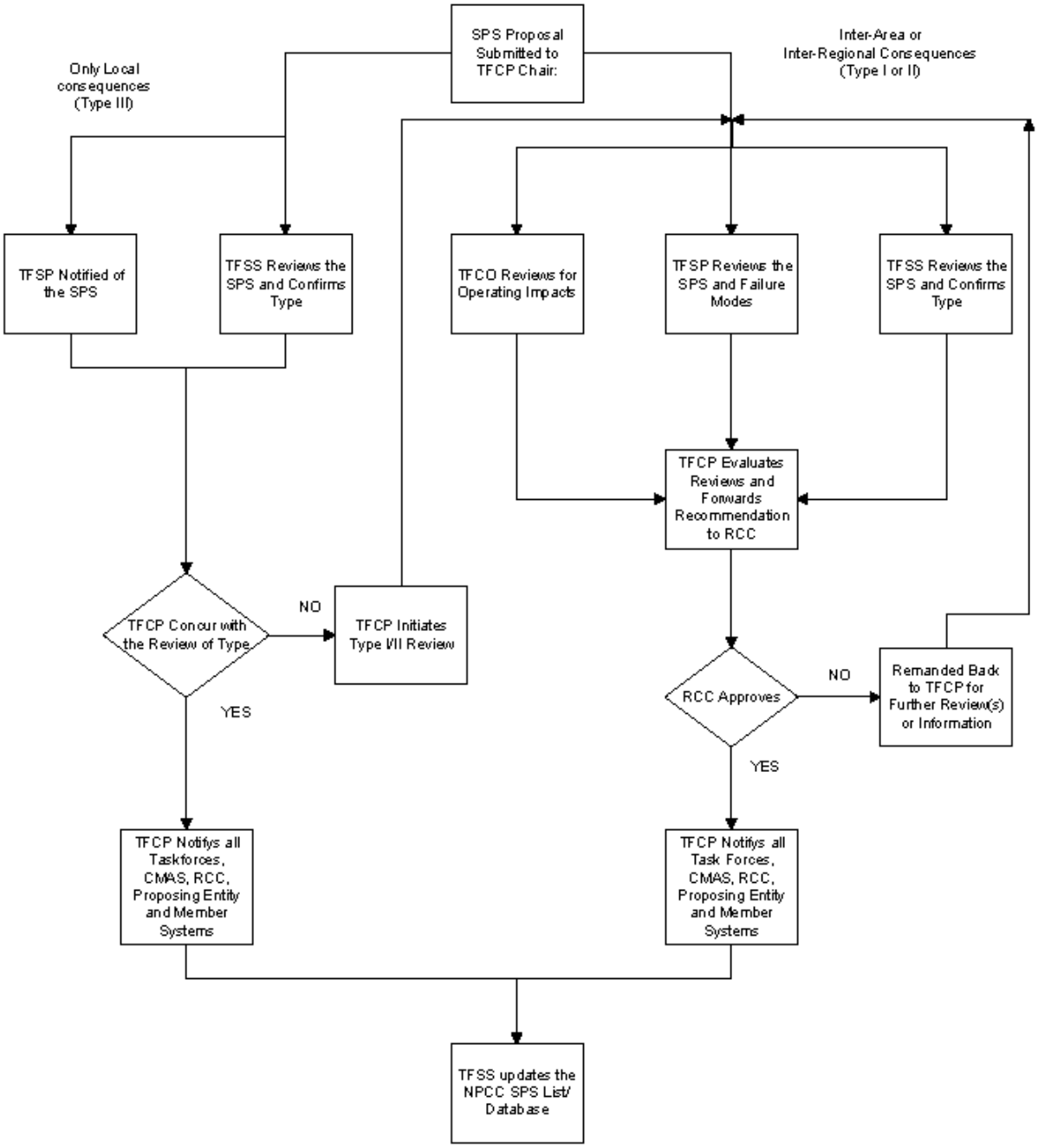
PROCEDURE FOR NPCC REVIEW OF NEW OR MODIFIED BULK POWER SYSTEM SPECIAL PROTECTION SYSTEMS (SPS)



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NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

September 11, 2012

NPCC Full Member Committee;

Please find attached a redlined copy of NPCC Regional Reliability Directory#12 *Underfrequency Load Shedding Program Requirements* which has been revised to incorporate certain tolerance recommendations in the five stage NPCC Automatic UFLS program and is now posted to receive your comments through the NPCC Process for Open Review.

During the recent development of the NPCC Regional Standard for Automatic UFLS *PRC- 006-NPCC-1* the Standard Drafting Team asked the SS-38 Working Group on Inter Area Dynamic Analysis to investigate the tolerances in the UFLS program and to further review the amount of margin that could be allowed at each stage.

The SS-38 Working Group observed in its simulations that using a UFLS program based on 1% tolerance bands generated more acceptable results and recommended that such tolerances be incorporated into the draft of *PRC-006-NPCC-1*.

The current version of NPCC Directory #12 which provides the criteria for the UFLS program until such time as the standard has been approved does not provide for any tolerances in its program stages.

Accordingly, this revision will synchronize the tolerance bands between Directory#12 and the UFLS Regional Standard and allow regional entities to implement a program that is consistent with the SS-38 design recommendations as part of the ongoing six year UFLS Implementation Plan.

The NPCC Task Force on System Studies (TFSS) has reviewed and approved the proposed changes and has authorized this Open Process posting.

The NPCC Open Process Review may be accessed through the following link:

https://www.npcc.org/Standards/SitePages/NonStandardsList.aspx

Comments on the proposed revision to Directory#12 will be received for forty five days through October 26, 2012 and all comments will be addressed by the TFSS.

Please contact me with any questions regarding Directory content or document review.

Thanks.

Gerry Dunbar
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NPCC
Regional Reliability Reference Directory # 12
Under frequency Load Shedding Program Requirements

Sept. 11, 2012
Posted for Open Process Review

Task Force on Coordination of Operations Revision Review Record:
June 26th, 2009
March 3rd, 2010

Adopted by the Members of the Northeast Power Coordinating Council, Inc. June 26th, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	6/26/09	Effective Date	New
1	3/03/10	Sections 5.2.2 and 5.2.3 revised to consider small entity participation.	Revision
2	1/06/2011	Section 1.4 revised to reflect RCC approved Quebec implementation.	Errata.

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Appendix A

1.0 Introduction

1.1 Title
Under frequency Load Shedding Program

1.2 Directory Number
12

1.3 Objective

This Directory presents the basic criteria for the design and implementation of under frequency **load shedding** programs to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements to prevent system collapse due to load-generation imbalance.

1.4 Effective Date
June 26th, 2009

The effective date of this Directory also is the initial date of a six-year implementation plan for under frequency **load shedding** program in the portion of NPCC in the Eastern Interconnection and a three -year implementation plan in the Québec Interconnection.

1.5 Background

This Directory was developed from the automatic Under frequency **Load Shedding** requirements in NPCC Directory #2, Emergency Operations, and the recommendations and implementation plans provided in the study reports: 2006 Assessment of Under frequency Load Shedding Adequacy Part III – Assessment of Program Modifications and 2008 Assessment of Under frequency Load Shedding Adequacy – Québec Area, approved by the Reliability Coordinating Committee on November 19, 2008.

1.6 Applicability

1.6.1 Functional Entities

Balancing Authorities
Transmission Operators
Generator Owners

2.0 Terms Defined in this Directory

The definitions of terms found in this Directory appearing in bold typeface can be found in the Appendix A.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing Requirements that are associated with this Directory include, but may not be limited to:

3.1 EOP-003: Load Shedding Plans
3.2 PRC-006: Development and Documentation of Regional UFLS Programs
3.3 PRC-007: Assuring Consistency with Regional UFLS Program Requirements

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Full Member, More Stringent Criteria

These Criteria are in addition to, or more stringent or more specific than the NERC or any Regional Reliability standard requirements.

5.1 Under frequency Load Shedding Program – General Criteria

The intent of the NPCC automatic Under frequency **Load Shedding** program is to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements stipulated in this document, as follows:

5.1.1 Frequency decline is arrested at no less than 58.0 Hz for the portions of NPCC in the Eastern Interconnection and 56.0 Hz for the portion of NPCC in the Québec Interconnection.

5.1.2 Frequency does not remain below 58.5 Hz for greater than 10 seconds, and does not remain below 59.5 Hz for greater than 30 seconds, for a generation deficiency of up to 25% of the **load**.

5.2 Under frequency Load Shedding Program – Eastern Interconnection specific Requirements

Each Balancing Authority in the NPCC portion of the Eastern Interconnection shall develop an automatic Under frequency **Load Shedding** Program that meets the following requirements, unless an alternative plan is submitted by the Balancing Authority for review by the NPCC Task Forces on Coordination of Operation and System Studies and approved by the NPCC Reliability Coordinating Committee:

5.2.1 The program shall consist of five stages of **load shedding** to be provided by entities with 100 MW or more of end-use load connected to its facilities with the following attributes:

	Threshold Setting	Block Size	Cumulative Load Shed as % of TO or DP Load	Total Operating Time (1)
Stage 1	59.5 Hz	6.5-7.5~~7~~ percent	6.5-7.5	300 ms
Stage 2	59.3 Hz	6.5-7.5~~7~~ percent	13.5-14.5	300 ms
Stage 3	59.1 Hz	6.5-7.5~~7~~ percent	20.5-21.5	300 ms
Stage 4	58.9 Hz	6.5- 7.5~~7~~ percent	27.5-28.5	300 ms
Stage 5 (anti-stall)	59.5 Hz	2-3 percent	29.5-31.5	10 s

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Notes:

(1) Total operating time is the load-weighted average for all **load** within a Balancing Authority area, with maximum deviation for any load limited to ±50 ms.

5.2.2 The program shall consist of two stages of **load shedding** to be provided by entities with 50 MW or more and less than 100 MW of end-use load connected to its facilities with the following attributes:

	Threshold Setting	Block Size	Cumulative Load Shed as % of TO or DP Load	Total Operating Time (1)
Stage 1	59.5 Hz	14-25 percent	14-25	300 ms
Stage 2	59.1 Hz	14-25 percent	28-50	300 ms

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Notes:

(1) Total operating time is the load-weighted average for all **load** within a Balancing Authority area, with maximum deviation for any load limited to ±50 ms.

5.2.3 The program shall consist of one stage of **load shedding** to be provided by entities with 25 MW or more and less than 50 MW of end-use load connected to its facilities with the following attributes:

	Threshold Setting	Block Size	Cumulative Load Shed as % of TO or DP Load	Total Operating Time (1)
Stage 1	59.5 Hz	28-50 percent	28-50	300 ms

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Notes:

(1) Total operating time is the load-weighted average for all **load** within a Balancing Authority area, with maximum deviation for any load limited to ±50 ms.

5.2.4 Entities with less than 25 MW of end-use load connected to its facilities are exempt from providing UFLS.

5.2.5 Entities with less than 100 MW of end-use load connected to its facilities may collectively implement by mutual agreement with one or more entities within the same island[1] identified an aggregated automatic UFLS program that sheds load based on the frequency thresholds in section 5.2.1 as an alternative to implementing the applicable program in section 5.2.2 or 5.2.3.

5.2.6 Under frequency threshold **relays** shall be set to a nominal total operating time of 300 ms, from the time when frequency passes through the set point to the time of circuit breaker contact opening (including any communications time delay), with a minimum relay operating time to be no less than 100 ms when the rate of frequency decay is 0.2 Hz per second.

5.3 Under frequency Load Shedding Program – Québec Interconnection Specific Requirements

The Balancing Authority in the Québec Interconnection shall develop an automatic Under frequency **Load Shedding** Program that meets the following requirements, unless an alternative plan is submitted by the

[1] BA shall identify the appropriate island for entities participating in the program.

Balancing Authority for review by the NPCC Task Forces on Coordination of Operation and System Studies and approved by the NPCC Reliability Coordinating Committee:

5.3.1 The program shall consist of five threshold stages and four rate-of-change (slope) stages of **load shedding** as depicted in Table 2.

Table 2 – UFLS Parameters for the Québec Interconnection Portion of NPCC

	Rate	Frequency	MW at System Peak	Mvar at System Peak	Total Operating Time
Threshold Stage 1	——	58.5 Hz	1000 MW (1)	1000 Mvar	300 ms
Threshold Stage 2	——	58.0 Hz	800 MW (1)	800 Mvar	300 ms
Threshold Stage 3	——	57.5 Hz	800 MW	800 Mvar	300 ms
Threshold Stage 4	——	57.0 Hz	800 MW	800 Mvar	300 ms
Threshold Stage 5 (anti-stall)	——	59.0 Hz	500 MW	500 Mvar	20 s
Slope Stage 1	-0.3 Hz/s	58.5 Hz	400 MW	400 Mvar	300 ms
Slope Stage 2	-0.4 Hz/s	59.8 Hz	800 MW (1)	800 Mvar	300 ms
Slope Stage 3	-0.6 Hz/s	59.8 Hz	800 MW (1)	800 Mvar	300 ms
Slope Stage 4	-0.9 Hz/s	59.8 Hz	800 MW	800 Mvar	300 ms

Notes:

(1) These stages shed fixed load independent of system load level.

(2) The amount of load shedding in this table includes load shedding to compensate for generators that trip above the curve in Figure 1.

5.4 Generator Under frequency Protection Requirements

Generators shall not be tripped for under-frequency conditions in the area above the curve in Figure 1, except as provided for in Sections 5.4.1 and 5.4.2.

5.4.1 It is recognized that, in special cases, requirements may dictate generator trip in the region above the curve. In those cases, the Generator Owner shall so notify its

Balancing Authority and shall ensure through alternate arrangements, that automatic **load shedding** additional to the amount set out in Section 5.2 and in Section 5.3, equivalent (+/- 5%) to the amount of **generation** to be tripped, is provided. Such cases shall be reviewed by the Task Force on Coordination of Operation

5.4.2 Generator Owners shall not increase the under frequency trip settings or make other modifications to the existing exempt generators (that trip above the curve in Figure 1) that may cause these generators to, directly or indirectly, trip at a higher frequency.

5.5 UFLS Program Assessment Requirements

5.5.1 Studies shall be performed by the associated Transmission Operator to ensure satisfactory voltage and loading conditions after automatic **load shedding**.

5.5.2 The Task Force on System Studies shall conduct a triennial study to coordinate the Automatic Under frequency **Load Shedding** Program among the NPCC Balancing Authorities.

6.0 Measures and Assessments

None developed at this time.

7.0 Compliance Monitoring

Adherence to these Criteria shall be reported by the responsible entity in a manner and form designated by the Compliance Committee.

Prepared by: Task Force on System Studies

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according

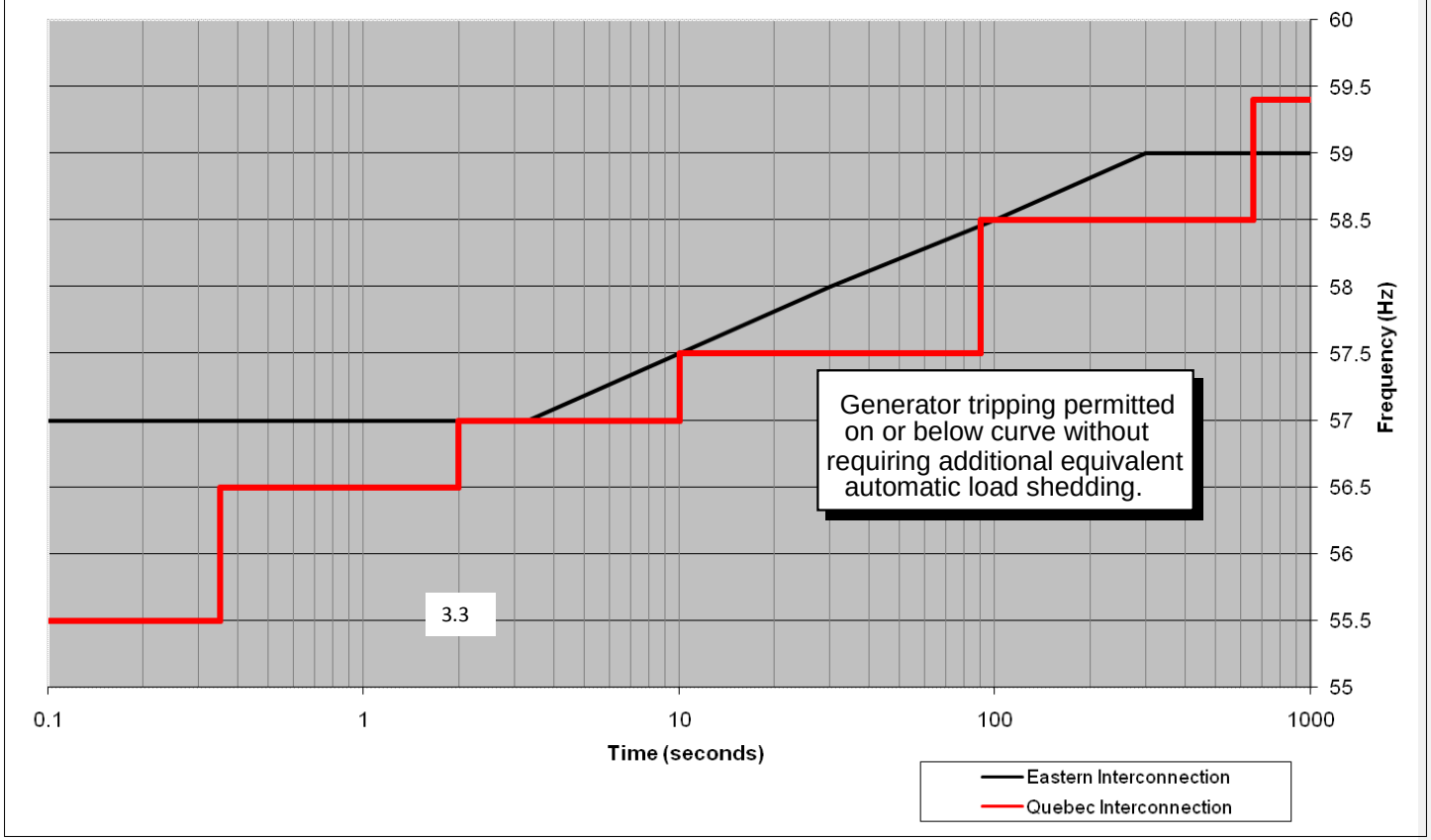
to the most current "NPCC Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of the document such as Links, glossary of terms, etc., will only require RCC Members' approval. Errata may be corrected by the Lead Task Force at any time and provide the appropriate notifications to the NPCC Inc. membership.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References: NPCC Directory #2 – Emergency Operations.

Figure 1
Standards for setting underfrequency trip protection for generators



Appendix A
Definition of Terms[2]

Bulk power system — The interconnected electrical systems within northeastern North America comprised of system **elements** on which **faults** or **disturbances** can have a **significant adverse impact** outside of the **local area**.

Island — A portion of a **power** system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system **elements**.

Load — The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

NPCC Specific Definitions:

Firm Load — Loads that are not **Interruptible Loads**.

Interruptible Load — Loads that are interruptible under the terms specified in a contract.

Load Shedding — The process of deliberately removing (either manually or automatically) preselected customers' **load** from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

Relay — An electrical device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).

[2] These terms will be moved and grouped under a separate Directory when all other Directories are developed.

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NPCC Request for Criteria Interpretation

Note: an Interpretation cannot be used to revise a Directory.

Request for an Interpretation of a Directory
Date submitted: 9/28/12 Date revised version submitted:
Contact information for person requesting the interpretation:
Name: David Balban
Organization: Consolidated Edison Company of New York, Inc.
Telephone: 212-460-1078
E-mail: balband@coned.com
Identify the Directory that needs clarification:
Directory Number : Directory #3 Section 5.6.2
Directory Title: Maintenance Criteria for Bulk Power System Protection
Identify specifically what portion of the Criteria needs clarification:
Text of Requirement: For telecommunication system channels that are not continuously monitored, the signal adequacy shall be tested every month and the ability of a channel to perform its intended function shall be verified every twelve months. An example of such a system is On/Off Power Line Carrier.

What is the difference between the monthly signal adequacy test and the yearly verification of the ability of the channel to perform its intended function? Our view is that the monthly signal adequacy sufficiently verifies the ability of the channel to perform its function; therefore, no yearly additional yearly test is required. The interpretation may depend on what is the definition of the intended function of the channel. We think the intended function of the channel is to transfer the signal from one station to the other, and therefore the monthly signal adequacy test verifies if that is working.

Identify the material impact associated with this interpretation:

Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this Directory:

Unessential yearly test performed.

Interpretation: Response to Request for an Interpretation of Directory XX for the XXXX Corporation
The following interpretation of Directory was developed by the Task Force on XXXXX
Directory Number and Text of Requirement
Question 1
Response to Question 1
Question 2
Response to Question 2

NPCC, Inc.

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NPCC Request for Criteria Interpretation

Note: an Interpretation cannot be used to revise a Directory.

Request for an Interpretation of a Directory
Date submitted: 11/8/2012 Date revised version submitted:
Contact information for person requesting the interpretation:
Name: Joel Charlebois on behalf of Paul DiFilippo Hydro One Networks
Organization: Acumen Engineered Solutions International Inc.
Telephone: 905-875-2075 ext 236
E-mail: joelc@aesi-inc.com
Identify the Directory that needs clarification:
Directory Number : **3**
Directory Title: Maintenance Criteria for Bulk Power System Protection
Identify specifically what portion of the Criteria needs clarification:
Text of Requirement: 5.7.1 **Protection group** DC circuit tests, battery bank and charger tests and breaker trip tests for **protection** required by the NPCC Automatic Underfrequency **Load Shedding**

Program, need not be performed more frequently than the **protection group** DC circuit tests, battery bank and charger tests and breaker trip tests for other **protection** on the same breaker. Because of the distributed nature of this **load shedding protection**, random failures to trip do not compromise the objectives of the NPCC Automatic Under frequency **Load Shedding** Program.

1 - What is meant where it states that DC circuit tests, battery bank and charger tests and breaker trip tests: "need not be performed more frequently than the protection group DC circuit tests, battery bank and charger tests and breaker trip tests for other protection on the same breaker"?

2 - Are DC circuit tests, battery bank and charger tests and breaker trip tests required for all protection equipment that is required by the NPCC UFLS program?

3 - Do the maintenance and testing activities and intervals from sections 5.3, 5.4, and 5.5 of NPCC Directory 3 for DC circuit tests, battery bank and charger tests and breaker trip tests, apply to all protection equipment required by the NPCC UFLS program?

Identify the material impact associated with this interpretation:

Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this Directory:

Incorrect interpretation could cause some entities to perform DC circuit tests, battery bank and charger tests and breaker trip tests on incorrect intervals, or could cause some entities to conclude that DC circuit tests, battery bank and charger tests and breaker trip tests are not required to be performed at all.

Interpretation: Response to Request for an Interpretation of Directory XX for the XXXX Corporation
The following interpretation of Directory was developed by the Task Force on XXXXX
Directory Number and Text of Requirement
Question 1
Response to Question 1
Question 2
Response to Question 2

NPCC, Inc.

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August 27, 2012

Scott Auxier
Bangor Hydro Electric Co.
21 Telcom Drive
Bangor, Me 04401

Re: NPCC Response to a Request for Criteria Interpretation on Regional Reliability Directory# 3 *Maintenance Criteria for Bulk Power System Protection*

Dear Mr. Auxier:

In accordance with the NPCC Directory Development and Revision Manual the Task Force on System Protection (TFSP) has considered your *Request for Criteria Interpretation* and has provided the attached response.

The subject request which seeks clarification of certain criteria within Directory#3 *Maintenance Criteria for Bulk Power System Protection* was reviewed and approved by the TFSP at its meeting on July 17th and 18th, 2012.

Please find attached the TFSP response along with the original Request for Interpretation.

NPCC has established an archive for this and other such requests in the Directory section of the NPCC website.

https://www.npcc.org/Standards/Directory%20Interpretations/Forms/AllItems.aspx

Please let me know if I can provide any further assistance in this matter.

Thank you.

Gerry Dunbar
Northeast Power Coordinating Council, Inc.
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NPCC Request for Criteria Interpretation

Note: an Interpretation cannot be used to revise a Directory.

Request for an Interpretation of a Directory
Date submitted: 7-9-2012 Date revised version submitted:
Contact information for person requesting the interpretation:
Name: Scott Auxier
Organization: Bangor Hydro Electric
Telephone: 207-973-2540
E-mail: sauxier@bhe.com
Identify the Directory that needs clarification:
Directory Number : 3
Directory Title: Maintenance Criteria for Bulk Power System Protection
Identify specifically what portion of the Criteria needs clarification:
Text of Requirement:

5.6.2 Channel Health

For telecommunication system channels that are continuously monitored and continuously provide verification of trip capability to an Operator, no additional testing is necessary.

What is meant by: "continuously provide verification of trip capability to an Operator"? As an example, we have an FSK communication channel of RFL-9745 tone sets. The Guard tones are continuously monitored and Loss of Communication is alarmed to our operators. There is also a Hardware Alarm that is monitored by the operators and seems to provide verification of trip capability. Does this system meet the requirements such that no additional Channel Health testing is required? As such may the telecommunications terminal equipment be tested on the same interval as the protection assembly?

Identify the material impact associated with this interpretation:

Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this Directory:

Incorrect interpretation will cause us to test on incorrect intervals. We will either not be meeting the criteria or over-testing which is both costly and potentially detrimental to system reliability.

Interpretation: Response to Request for an Interpretation of Directory XX for the XXXX Corporation
The following interpretation of Directory was developed by the Task Force on XXXXX
Directory Number and Text of Requirement
Question 1
Response to Question 1
Question 2
Response to Question 2

Task Force on System Protection

Response to Request for Interpretation

Directory#3 Maintenance Criteria Bulk Power System Protection

What is meant by: "continuously provide verification of trip capability to an Operator"?

What is meant here, is that the communications equipment is capable of detecting and alarming (to an operator) failure modes that could prevent the trip signal from reaching the remote end.

As an example, we have an FSK communication channel of RFL-9745 tone sets. The Guard tones are continuously monitored and Loss of Communication is alarmed to our operators.

In your FSK example, the alarming would have to give an indication of the equipment's ability to actually send a trip signal to the remote end, not just the presence of the guard tone.

There is also a Hardware Alarm that is monitored by the operators and seems to provide verification of trip capability.

It is TFSPs understanding of this RFL equipment, that the hardware alarm is not a trip capability alarm so much as it is a hardware failure alarm, which is one failure mode, but not all failure modes.

Does this system meet the requirements such that no additional Channel Health testing is required?

This system meets the channel health testing requirements but does not provide trip capability verification, which is required annually.

As such may the telecommunications terminal equipment be tested on the same interval as the protection assembly?

The Contact outputs from the telecommunications equipment can be tested on the same interval as the protection assembly. For example, your RFL equipment may pick up an auxiliary device which has contact outputs going into your protection assembly…These contacts do not fall under the telecommunications equipment testing requirements but instead under the protection assembly testing requirements.

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June 18, 2012

Alan Adamson
New York State Reliability Council, LLC
1907 Evva Drive
Schenectady, NY 12303

Re: NPCC Response to a Request for Criteria Interpretation on Regional Reliability Directory# 8 *System Restoration.*

Dear Mr. Adamson:

In accordance with the NPCC Directory Development and Revision Manual the Task Force on Coordination of Operation (TFCO) has considered your *Request for Criteria Interpretation* and has provided the attached response.

The subject request, which seeks clarification of certain criteria within Directory#8 *System Restoration,* was initially reviewed by the NPCC Restoration Working Group (CO-11) and was further revised and approved by the TFCO on June 6th, 2012.

Please find attached the TFCO response along with the original Request for Interpretation and the TFCO transmittal letter.

In the future NPCC will archive these documents and other such requests in the Directory section of the NPCC website.

Please let me know if I can provide any further assistance in this matter.

Thank you.

Gerry Dunbar
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NPCC Request for Criteria Interpretation

Note: an Interpretation cannot be used to revise a Directory.

Request for an Interpretation of a Directory
Date submitted: May 25, 2012 Date revised version submitted:
Contact information for person requesting the interpretation:
Name: Alan Adamson
Organization: New York State Reliability Council (NYSRC) Reliability Rules Subcommittee
Telephone: 518-355-1937
E-mail: aadamson@nycap.rr.com
Identify the Directory that needs clarification:
Directory Number : 8
Directory Title: System Restoration
Identify specifically what portion of the Criteria needs clarification:
Text of Requirement: Requirement 5.7.2.1 "The Generator Owner having generating facilities designated as having black start capability shall annually verify the facilities' black start capability without dependencies on power sources unavailable during a partial or complete system blackout….The number of units within a generating facility that shall be black started for this test is determined by the

Reliability Coordinator and Transmission Operator as needed by their respective system restoration plans."

Clarifications requested by the NYSRC:

1. NPCC Requirement: Designated black start facilities shall be tested annually.
   Is a power plant considered a facility or could there be more than one facility in a power plant? For example, if a power plant has two steam units and four gas turbines, and all six units are designated as black start units: (1) Are all six units defined collectively by NPCC as a single facility? or (2) Could there be more than one facility in the plant, say three units in one facility and three units in the other? If NPCC interprets that all six units make up one facility in this example, does this mean that, at a minimum, only one of the six black start units needs to tested each year? (We recognize that the RC and TO can determine to test more than the minimum number of units required by NPCC.)

2. Is the subject NPCC criterion applicable to required black start facility actions necessary for implementing a local Transmission Owner's system restoration plan?

Identify the material impact associated with this interpretation:

Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this Directory:

NYSRC policy requires that the NYSRC must be assured that the NYISO complies with NPCC standards and criteria. Also, NYSRC Reliability Rules must, at a minimum, be consistent with NPCC requirements, although they may be more stringent or specific.

An incorrect interpretation of NPCC requirements could result in incorrect conclusions regarding NYISO compliance with NPCC requirements, or NYSRC reliability rules that are inconsistent with NPCC requirements.

Interpretation: Response to Request for an Interpretation

The following interpretation of Directory#8 *System Restoration* was developed by the Task Force on Coordination of Operation (TFCO)

Directory Number: Directory#8

1. **Question 1:**

   NPCC Requirement: Designated black start facilities shall be tested annually.

   Is a power plant considered a facility or could there be more than one facility in a power plant? For example, if a power plant has two steam units and four gas turbines, and all six units are designated as black start units: (1) Are all six units defined collectively by NPCC as a single facility? or (2) Could there be more than one facility in the plant, say three units in one facility and three units in the other? If NPCC interprets that all six units make up one facility in this example, does this mean that, at a minimum, only one of the six black start units needs to tested each year? (We recognize that the RC and TO can determine to test more than the minimum number of units required by NPCC.)

Response to Question 1:

Response of the NPCC Task Force on Coordination of Operation:

A generating plant with Blackstart Capability may have black start generating units as well as generating units which are not black start capable. Citing Requirement 5.7.2.1:

"The Generator Owner having generating facilities designated as having blackstart capability shall annually verify the facilities' blackstart capability without dependencies on power sources unavailable during a partial or complete system blackout. Once the facility has been started, it shall continue to demonstrate its capability to operate in a stable condition while isolated from the power system for a minimum of ten minutes. The number of units within a generating facility that shall be blackstarted for this test is determined by the Reliability Coordinator and Transmission Operator as needed by their respective system restoration plans."

Question 2 :

Is the subject NPCC criterion applicable to required black start facility actions necessary for implementing a local Transmission Owner's system restoration plan?

Response to Question 2

Response of the NPCC Task Force on Coordination of Operation:

No. The requirements of NPCC Directory 8 are limited to Black start Capability at designated Key Facilities as identified by the Reliability Coordinator in accordance with the following definitions as found in the NPCC Glossary of Terms::

"Black start Capability — The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system."

"Basic Minimum Power System — Consists of one or more generating stations, transmission lines, and substations operating in the form of an island. Such a system can be restarted independently and later synchronized to other islands or the main grid. The transmission elements included in the basic minimum power system connect the units which have black start capability to those units without black start capability which have been designated in the restoration plan to be restarted in the first stages of the restoration process. Also included are selected tie lines and corresponding substations, which are considered essential to the formation of a larger power system. The intent is to focus on the ability to create smaller electrical systems or islands, which can be expanded and synchronized to other such islands and the main grid."

"Key Facilities — Facilities required to establish a basic minimum power system following a system blackout. These facilities are essential to the restoration plan of the Control Area and include generating stations having black start units and other selected generating stations, transmission elements which are part of the basic minimum power system, control centers and telecommunication centers and telecommunication facilities which are necessary to support protection and control facilities, voice and data between and within control centers and voice and data between control centers and key generating / transmission substations."

From:	Gerard J. Dunbar
To:	dverner@nbpower.com; tfsp-members
Cc:	Balban, David M (BALBAND@coned.com); joelc@aesi-inc.com; grpStaff
Subject:	Request for Interpretation NPCC Directory#3
Date:	Friday, November 09, 2012 2:20:43 PM
Attachments:	Con Edison and Hydro One Directory 3 Interpretation Requests GJD 20121109.pdf

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November 9, 2012;

Daren and TFSP…… please find attached a completed Request for Interpretation which has been revised to include a second request seeking clarification on the criteria language within NPCC Directory#3 *Maintenance Criteria for Bulk Power System Protection*.

On September 28, 2012 Con Edison submitted a Request for Interpretation on language surrounding Section 5.6.2 of the document and that request is pending TFSP review.

Recently a second such request has been received from Hydro One Networks on the language in Section 5.7.1 of Directory#3 and I have incorporated and bookmarked both requests into a single attachment to facilitate the TFSP review.

Please consider reviewing both requests at your upcoming meeting next week.

Additionally and as a reminder, the TFSP recently addressed an interpretation from Bangor Hydro on Section 5.6.2 of Directory#3; however the context of the attached Con Edison request on Section 5.6.2 differs from the prior request.

Please let me know if I can assist in the TFSP review of these requests.

I've attached a link to the NPCC Directory Development and Revision Manual which contains the Criteria Interpretation process.

https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

Thank you for your consideration.

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