**From:** Jordan Mallory
**To:** canonly
**Subject:** NERC Announcement: Activity on Compliance Website
**Date:** Friday, May 18, 2012 3:01:27 PM

# NERC Compliance Announcement

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## CAN-0038 has been removed from development process

CAN-0038 addressed the issue of how many hours constitutes five days of training, which was resolved for both the PER-002-0 R4 and PER-004-1 R2 requirements by PER-005-1 R3 (enforceable April 1, 2011). This CAN has been removed from the NERC website and is documented under the "issues that have been addressed" section of the Priority List of CANs spreadsheet. In addition, the prioritization of potential CAN issues has been updated based on feedback from NERC committees and registered entities. To view the CAN status and priority list, click here.

## Entity Assessment Focus Group Reports have been posted

NERC conducted eight focus groups to obtain function-specific input for the development of the Entity Assessment template. There were two focus groups conducted for each of the following:

- Balancing Authorities/Reliability Coordinators
- Smaller Entities
- Generator Operators/Generator Owners
- Transmission Operators/Transmission Owners

The reports from these focus groups, as well as a summary for all of the focus groups, have been posted on the NERC website. The information gathered from these focus groups has been provided to the Compliance and Certification Committee (CCC) working group. The input received from these focus groups and questions the attendees raised will be an important contribution to the Entity Assessment project.

The reports have been placed in a new section (Entity Assessment Template) on the Compliance page of the NERC website. Once a permanent name for the template has been determined, the title of this section will be changed. Over the next couple of weeks another area (gray bar) will be added to this section that will provide entities with an ongoing status update for the project.

## RSAWs have been moved to a new location

Current RSAWs for use, DRAFT RSAWs for Industry Review, RSAW Tools and Industry Feedback are all now located at the following link. Please use the RSAW Feedback Form located in the "Tools" section when providing feedback on draft RSAWs.

For general information regarding Compliance, please contact Mike Moon at 404-446-2567 or Valerie Agnew at (404) 446-2566. For information on CANs, contact Ben Engelby at 404-446-2578, and for RSAWs contact Caroline Clouse at 404-446-2588.

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| CAN Number | CAN Requestor | Status | Standard | Topic of CAN | Item Description/Driver for Request (NERC has tried to identify these issues without identifying regions or registered entities; the description is a summary at the time of quarterly prioritization. It may not include all the related information currently identified with each possible CAN; NERC will document other information related to each within that CANs development history. Items listed here may require more than one CAN per standard or a group of similar issues into one CAN, depending on efficiencies, other NERC-wide efforts, etc.) | Last Updated: 5/18 |
|---|---|---|---|---|---|---|
| **CANs in Development or Final** | | | | | | Related SDT Project o of New/Revised Stan |
| 5 | | Final | CIP-002-3 R3 | Critical Cyber Asset Designation for System Operator Laptops | Registered entities and Regional Entities requested clarity regarding whether system operator laptops with the capability and purpose of controlling Bulk Electric System assets remotely (whether in normal operations or in emergencies) should be designated as Critical Cyber Assets (CCAs). | Project 2010-INT-05 CIP-002-1 to the operation of a Critical As |
| 6 | | Final | EOP-005-1 R7 | Verification of Restoration Procedure | This CAN provides instruction for assessing whether: 1) an entity has verified its restoration procedure "by actual testing or by simulation," as required by EOP-005 R7, and 2) the use of a third-party vendor impacts a registered entity's obligation under the standard. | EOP-005-2 Enforceable 7/1/201 |
| 7 | | Final | CIP-004-3 R4.2 | Revocation of Access (physical and electronic) to CCAs | Registered entities and Regional entities requested clarity about the extent and timing of revocation of access to Critical Cyber Assets (CCAs) required in CIP-004 R4.2. Specifically, clarity was sought on what constitutes revocation and access (physical and electronic), to CCAs under different entity-specific scenarios. | Project 2008-06 Cyber Security |
| 8 | | Final | PRC-005 R2 | Basis for First Maintenance and Testing Date | NERC Compliance received a request for clarification on PRC-005 R2 regarding the monitored timeframes for gathering evidence pre-June 2007 when determining compliance with an entity's maintenance and testing program. What is the validity of a Regional auditor to ask for evidence pre-June 2007 even though there was no obligation to retain records until at least June 17, 2007? | Project 2007-17 Protection Syst |
| 9 | | Final | FAC-008 R1<br>FAC-009 R1, R2 | Facility Ratings and Design Specifications | This CAN provides instruction for assessing compliance with FAC-008 R1 and FAC-009 R1 when an entity's constructed Facilities do not match its design specifications. | FAC-008-3 Enforceable 1/1/201 |
| 10 | | Final | Multiple | Implementation of "Annual" in NERC Reliability Standard Requirements | This CAN discusses the implementation of annual requirements when the term "annual" is not defined by the standard. | |
| 11 | | Final | PRC-005 R2 | Interval Start Date for New Equipment | NERC Compliance received a request for clarification on PRC-005 R2 regarding gathering evidence of initial testing for new equipment. | Project 2007-17 Protection Syst |
| 12 | | Final | Requirement of periodic action by Effective Date | Completion of Periodic Activity Requirements During Implementation Plan | Registered entities and Regional entities have requested that NERC provide clarification on whether a registered entity must provide evidence that it completed a periodic action or event required by a NERC Reliability Standard prior to the registered entity's Effective Date for the standard. | |
| 13 | | Final | PRC-023 R1 and R2 | Effective Dates for Switch-On-To-Fault Schemes | This CAN clarifies the Effective Dates for SOTF schemes included on 1) transmission lines operated at 200 kV and above, and 2) transformers with low voltage terminals connected at 200 kV and above, under PRC-023 R1 and R2. | PRC-023-2 has tiered enforceat details |
| 15 | | Final | EOP-002 Attachment 1;<br>EOP-005 R11.3;<br>IRO-002 R4, R5, R6;<br>IRO-003 R1, R2; | Unavailability of NERC Software Tools | NERC Compliance received a request for clarification on a suite of reliability standards that require the use of a NERC tool. What is a registered entity's performance obligation to a standard's requirements when a NERC Tool is unavailable? | EOP-005-2 Enforceable 7/1/201<br>Project 2006-06 Reliability Coor IRO-005) |
| 17 | | Final | CIP-007 R5 | Technical and Procedural System Access and Password Controls | Is a CEA is to verify that technical controls, procedural controls, or both are implemented in assessing compliance with CIP-007 R5? | Project 2012-INT-03 CIP-007 fo |

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| 18 | | Final | FAC-008 R1.2.1 | Terminal Equipment | This CAN provides instruction for assessing what equipment should be considered “terminal equipment” under FAC-008. | FAC-008-3 Enforceable 1/1/201 |
| 19 | | In Development | CIP-007 R3 | Implementation of Software Security Patches | Is a registered entity required to have a technical control for password configuration or would a manual solution meet the requirement? How would a manual solution be audited? When and under what conditions is a TFE is required? | Project 2008-06 Cyber Security |
| 20 | | Final | TPL-002 R1.3, R6, R11<br>TPL-003 R1.3.12<br>TPL-004 | Equipment Outages | NERC received a request for clarification of whether maintenance outages, including Protection Systems, must be included in operational planning studies under TOP-002 or in transmission planning assessments under TPL-002, TPL-003, and TPL-004. | Project 2007-03 – Real-time Op<br>Project 2012-INT-02 TPL-003a &<br>TPL-002-1, TPL-003-1, TPL-004-<br>approval |
| 22 | | Final | VAR-002 R1 | Generator AVR Operation in Alternative Mode | NERC received requests for clarification regarding whether a generator may be operated in manual mode during start-up. | Project 2011-INT-02 Interpretat<br>Constellation Power Gen |
| 23 | | In Development | CIP-005 R3<br>CIP-006 R6<br>CIP-007 R6 | Logging system failures | NERC received a request for clarification of whether any exception exists for an entity that cannot log access 100% of the time, 24 hours per day, seven days per week, and if not, whether the entity needs to file a self-report any time the access logging system fails. | Project 2008-06 Cyber Security |
| 24 | | Final | CIP-002 R3.1 | Routable Protocols and Data Diode Devices | NERC received a request for clarification of whether the communication characteristics of data diode devices can be used to exclude non-critical Cyber Assets from consideration as CCAs when a routable protocol is implemented, thereby making them inapplicable to CIP standards. | Project 2008-06 Cyber Security |
| 26 | | Final | TOP-006 R3 | Protective Relays | NERC received a request for clarification of whether an RC, TOP and BA, under TOP-006 R3, needs to provide appropriate technical information to its operating staff for all protective relays in its area whether or not it has the responsibility or ownership of the protective relays. | Project 2010-INT-01 Interpretat |
| 27 | | Final | TOP-003 R2 | Coordination of Scheduled Outages | NERC received a request to clarify whether TOP-003 R2 requires the BA to plan and coordinate scheduled outages of generators within the BA’s area. | Project 2007-03 – Real-time Op<br>Project 2010-INT-01 Interpretat |
| 28 | | Final | TOP-006 R1.2 | Reporting Responsibilities | This CAN provides instruction for assessing whether a BA or TOP has fulfilled the requirements for reporting transmission or generation resources available for use to RCs and other affected BAs and TOPs under TOP-006 R1.2. | Project 2010-INT-01 Interpretat |
| 29 | | Final | PRC-004 R2 R3 | Protection System Misoperations | NERC received a request for clarification regarding whether entities must develop and implement Corrective Action Plans (CAPs) for, and maintain a record of, all Misoperations or only those that must be reported to NERC/RAPA. | Project 2010-05.1 Phase 1 of Pr<br>Misoperations |
| 30 | | Final | Attestations | Attestations | NERC received a request for clarification regarding the appropriate situations and uses of attestations as evidence of compliance with a reliability standard. | |
| 31 | | Final | CIP-005<br>CIP-006<br>CIP-006 R1.1 | Acceptable Opening Dimensions | NERC received a request to define the entry point metric definition of the access points on the perimeter. NERC also received a request for clarification for an acceptable entry point into a Physical Security Perimeter (PSP) of CCAs, as well as acceptable opening dimensions. | Project 2008-06 Cyber Security |
| 33 | | In Development | PRC-023 R1.1, R1.6, R1.7, R1.8, R1.9 | Transmission Relay Loadability | NERC Compliance received a request for clarity on: load remote to system; generation remote to load; if there is a 4-hour load rating or can a seasonal facility rating be used for R1.1 Furthermore, in a Directional Comparison Blocking (DCB) Scheme, does the reverse looking zone need to comply with PRC-023 loadability requirements? | Project 2010-13.2 Generator Re<br>PRC-023-2 has tiered enforceab<br>details |
| 34 | | In Development | EOP-002 R1<br>IRO-001 R3<br>TOP-001 R1 | Use of Authority Letters | NERC received a request to clarify what criteria auditors consider when reviewing an authority letter. | Project 2006-06 Reliability Coor |

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| 35 | | In Development | Periodic Data Submittals | Periodic Data Submittal Violations | NERC received a request for clarification of whether violations would be mitigated if they were included in periodic data submittals. | |
| 37 | | In Development | Roll-up Violations | Roll-up Violations | NERC received a request for clarification regarding whether the finding of non-compliance of one requirement would be applied across other standards to which that requirement applies. | |
| 39 | | Final | DOE 417 | Filing DOE Form OE-417 Event Reports | The Department of Energy's (DOE) new online process for submitting the OE-417 disturbance reporting form does not automatically issue a copy to NERC or the Regions. | Project 2009-01 Disturbance an |
| 40 | | Final | BAL-003 R2 | Frequency Bias Calculation | NERC received a request for clarification on the proper approach to determine Frequency Bias Setting. | Project 2007-12 Frequency Res |
| 41 | | In Development | IRO-004 R1 | Dynamic Modeling in a Next-Day Assessment | NERC received a request for clarification on whether complete dynamic modeling is required for next-day assessments. | |
| 42 | | In Development | PRC-001 R1, R2, R4 | System Protection Coordination | NERC received a request to clarify what types of evidence is required to demonstrate that system protection is coordinated among applicable entities under PRC-001. | Project 2007-06 System Protect |
| 43 | | Final | PRC-005 R2 | Protection System Maintenance and Testing Evidence | NERC received requests for clarification on what types of evidence are typically used to demonstrate compliance with Protection Systems maintenance and testing in certain compliance areas. | Project 2007-17 Protection Syst |
| 44 | | In Development | TOP-001 R1, R2, R5, R8 | Operating Emergencies and Emergency Conditions | NERC received a request for clarification on the definition of emergency, operating emergency and system emergency as used in TOP-001. There are several references to the word emergency in TOP-001, but none of those references are capitalized to indicate a glossary term. | Project 2007-03 – Real-time Op |

| **Prioritized CANs** | **Source** | **Status** | **Standard** | **Topic of CAN** | **Item Description/Driver for Request**<br>**(NERC has tried to identify these issues without identifying regions or registered entities; the description is a summary at the time of quarterly prioritization. It may not include all the related information currently identified with each possible CAN; NERC will document other information related to each within that CANs development history. Items listed here may require more than one CAN per standard or a group of similar issues into one CAN, depending on efficiencies, other NERC-wide efforts, etc.)** | **Related SDT Project of New/Revis** |
|---|---|---|---|---|---|---|
| **HIGH** | Registered Entity | Prioritized | CIP-002-3 | CCA designation of management console for virtual machine (VM) technology | With the Management Console having the capabilities for impacting the CCA VM Client, the Management Console should be considered a CCA. With the expanded usage of Virtual Machine technology it is in the best interest of the industry to have this clearly outlined to make sure the overall reliability of the BES is maintained. | Project 2008-06 Cybe |
| **HIGH** | Registered Entity | Prioritized | CIP-007-3 | Whether USB-only printers are considered Cyber Assets | Is a USB-only printer a Cyber Asset, or is it only a peripheral device? The term "printer" also needs to be clarified for compliance purposes. What is considered peripheral and what is considered serial.<br><br>The Glossary definition of a Cyber Asset is: "Programmable electronic devices and communication networks including hardware, software, and data." | Project 2008-06 Cybe |
| **HIGH** | CEAs<br>Registered Entity | Prioritized | COM-001 R1.1-R1.4 | Telecommuncation Redundancy | Is a single point of failure an automatic failure to comply with R1.1 - 1.3. If a facility is not sufficiently redundant, is an entity automatically out of compliance with all R1 sub requirements but only R1.4? How does a CEA determine in what situations facilities must be redundant and diversely routed? How do the CEAs assess whether the facilities are redundant (i.e. how far back in the provider system do you go)? | Project 2006-06 Relia |

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| **HIGH** | Region<br>Registered Entity | Prioritized | EOP Standards | Evidence of communication capability, access and verification under the EOP Standards | NERC Compliance received a request for clarification regarding what evidence a CEA will verify to determine compliance in regard to communication, capability and access using NERC software tools. (RCIS, WECCnet) | EOP-001-1, EOP-005-2, EOP-0 |
| **HIGH** | Registered Entity | Prioritized | FAC-003 R1 | TVMP Changes | NERC received multiple requests for clarification on FAC-003-1 R1 regarding the allowable timeframe for implementation when an entity changes one TVMP plan based on normal trend to another TVMP plan based on clear cut. Once changed is the entity bound to implement immediately? Does the standard provide for entities to have a transition period while changing TVMP plans? | FAC-003-2 Adopted by NERC B<br>pending regula |
| **HIGH** | Registered Entity | Prioritized | Multiple | Definition of radial transmission | Source documents from multiple regions and from NERC demonstrate the inconsistent application of "radial." | Project 2010-17 Defin |
| **HIGH** | NERC | Prioritized | PER-002-0 | Consistency of evidence for operating personnel training | Clarification may be necessary to ensure that Registered Entities understand what types of operating personnel training is expected and to provide auditors with a consistent approach for determining compliance with PER-002. This issue may be resolved with PER-005 R3, which states: At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, | PER-003-1 Enforce<br>PER-005-1 R1 & R2 En<br>PER-005-1 R3 Enfo<br>PER-005-1 R3.1 Enfo |
| **HIGH** | NERC | Prioritized | PER-002-0<br>PER-003 | Certification of Remote Operators | Which control center operators, remote or local or both, need to be NERC-certified system operators to be in compliance with PER-002 and PER-003? One position states that if an operator is performing (or sending an associated directive to field personnel to perform) an activity within one of the certified functions (being BA, TOP, or RC) the operator must be certified regardless of being remote or local. | PER-003-1 Enforce<br>PER-005-1 R1 & R2 En<br>PER-005-1 R3 Enfo<br>PER-005-1 R3.1 Enfo |
| **HIGH** | Registered Entity | Prioritized | PRC-004 | Consistent reporting of protection system Misoperations | Clarify the audit scope for Misoperations and CAPs to be reviewed. Request clarification as to whether non-reportable Misoperations are subject to compliance audits. Recommendation that an audit can cover any time and any action within the audit period regardless of reportability of misoperations. Also, does operation of a relay during an abnormal condition constitute a misoperation under PRC-004? | Project 2010-05.1 Phase<br>Misoper |
| **HIGH** | Registered Entity | Prioritized | TOP-002 R2, R6, R8, R10, R11, R19 | System Conditions | R6: What is the responsibility of the BA to plan to meet CPS and DCS under unscheduled changes in the system configuration and generation dispatch? R2, R8, and R19: Clarity on BA obligations; the request for clarity seems to try to change the standard. R6 and R10: BA and TOP applicability to the standard. | Project 2007-03 Rea |
| **MEDIUM** | Registered Entity | Prioritized | CIP-004 R3.1 | Criminal background checks | Clarification regarding the use of criminal history checks conducted by the FBI in support of the Access Authorization process mandated by the US Nuclear Regulatory Commission. Many companies rely on this process to support their CIP Personnel Risk Assessments (PRA) conducted under the CIP-004 standard. We think a CAN addressing the acceptability of this practice would help provide clarity to the process. | Project 2008-06 Cybe |
| **MEDIUM** | Registered Entity | Prioritized | EOP-003 R3 & R5 | Applicability of BA or TOP to automatic load shedding or manual load shedding | NERC Compliance received a request for clarity regarding the BA and TOP applicability with regard to compliance with the EOP-003. Also, does this apply only to automatic load shedding or does it also apply to manual load shedding? | EOP-003-2 Adopted by NERC B<br>pending regula |
| **MEDIUM** | Registered Entity | Prioritized | FAC-014 R5 | Responsibility for SOLs and IROLs | Clarification is needed to demonstrate that each applicable function is responsible for establishing SOLs and IROLs regardless of whether the registered entity is included in the studies performed by an RC or PA.<br>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 | Project 2006-06 Relia |
| **MEDIUM** | Registered Entity | Prioritized | IRO-005 R10 | What does the term 'derived limits' mean in general and with regard to small generators? | The confusion with IRO-005-3a R10 is that it is not clear what the auditors would deem to be “derived limits” and what their approach would be to a small generator “…operating the Bulk Electric System.” What is also not clear is how auditors would approach independent entities even becoming aware of derived limits. | Project 2006-06 Relia |
| **MEDIUM** | NERC | Prioritized | PRC-008 R1<br>PRC-011<br>PRC-017 R1.1 | Does the term "Protection System" include UFLS and UVLS equipment? Also, is control circuitry considered part of an SPS and does that circuitry fall under the definition of a Protection System? What constitutes a Special Protections | Consider defining UFLS equipment as a Protection System or explicitly list what is included as part of UFLS equipment in order to remove confusion concerning this terminology. There is uncertainty as to what equipment is considered part of the Protection System, which has led to inconsistent applications to TOs and DPs with a UFLS Program. Clarify whether PRC-017 R1.1 specifically includes control circuitry as part of an SPS or if SPS falls under the definition of a Protection System. | Project 2007-17 Protection Syst |
| **MEDIUM** | Registered Entity | Prioritized | TOP-002 R14, R16, R17 | Intentional Time Delays notifying BA and RC | Define "Intentional Time Delay" as outlined in TOP-002 R14, R16 and R17.<br><br>TOP-002 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: | Project 2007-03 Rea |

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| **MEDIUM** | Registered Entity | Prioritized | EOP-008-0 R1 | Implementation Plan and Test Drills | 1. Does the requirement to have a plan imply the implementation of that plan? 2. R1 states that a RC, TOP, and BA must have a plan to continue reliability operations in the event its control center becomesinoperable. R1.1 talks about the contingenct plans must be "viable and R1.5 talks abpout tests or drill "to ensure viability of the plan." Guidance is requested to clarify what is required to demonstrate the "viability" of a plan. Do test drills need to include the time-period covering the ramping of all | EOP-008-1 Enforc |
| **MEDIUM** | Registered Entity | Prioritized | PRC-017-0 R1.1 | Maintance and Testing Plans for SPS | R1.1 states that SPS identification shall include but is not limited to: relays, instrumnent transformers, communication systems, and batteries. Does a SPS to fall under the NERC definition of a Protection System? SPS includes control circuitry which would be included in the Protection System maintenance and testing plan. Guidance is requested to clarify what is expected to be addressed in the maintenance plan for a SPS. | Project 2007-17 Protection Syst |
| **MEDIUM** | Registered Entity | Prioritized | TPL-002 R1.3.10<br>TPL-003 R1.3.10<br>TPL-004 R1.3.7 | Power flow models and protection systems include relay devices as N-1 | Clarification requested on whether the inclusion of redundant and backup protective system failures is required in power flow models. | Project 2012-IN-02 TPL-003<br>TPL-002-1, TPL-003-1, TPL-<br>Appro |
| **LOW** | Registered Entity | Prioritized | CIP-003 R4 and R5 | Protection and access control to CCA information | Clarify whether hashing is an acceptable method for information authentication in order to be in compliance with the requirements for authenticating secure messages. | Project 2008-06 Cybe |
| **LOW** | Region | Prioritized | IRO-002 R3 | Applicability of BA and TOP | Clarity requested from a region on the RC, BA, and TOP applicability. What must the BA and TOP do to comply with IRO-002 R3?<br><br>IRO-002 R3 states: Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission | Project 2006-06 Relia |
| **LOW** | Registered Entity | Prioritized | Multiple | Mapping of registered entity policies to NERC Standard Requirements | If an entity has one or more policies for any standard to demonstrate/define how it meets the requirements and sub-requirements how within the policy or policies the CEA is to verify each of the components laid out in the requirement and sub-requirements. | |
| **LOW** | NERC/Region | Prioritized | TPL-003-0 | Application of TPL-003 Table 1 | Application of Table 1 in TPL-003 and proper modeling of contingency events (ie: Category C vs. D). Confusion about what is an extreme event and misunderstanding of categorizing simulations (found in Table 1 of the TPL standards) on the final outcome after the fault was cleared instead on the initiating event/fault as required. | Project 2012-IN-02 TPL-003<br>TPL-002-1, TPL-003-1, TPL-<br>Appro |
| **LOW** | Registered Entity | Prioritized | MOD-018 R1 | Definition of "non-member entities" | Clarity regarding what is included as a "non-member" as found in MOD-018 R1.<br><br>MOD-018 R1 states: The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner's report of actual | |
| **LOW** | Registered Entity | Prioritized | COM-002 R1.1 | Communication Paths and Directives | 1. Does "predetermined communication paths" in R1.1 mean certain operators in the control room rather than facilities peoviding the communication paths? R1.1 states "Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through | Project 2006-06 Relia<br>Project 2007-02 Operating P<br>Proto |
| **LOW** | Registered Entity | Prioritized | EOP-005-1 | Restoration Plan Coordination | 1. Does a GO that does not participate in the blackstart process need to coordinate restoration plans?<br>2. Discussions arose regarding the applicability of this requirement as it relates to long term scheduled equipment outages. Should an entities restoration plan be reviewed and updated for long term scheduled equipment outages as these change the | EOP-005-2 Enforc |

| CAN Number | Reasoning | Status | Issues that have been addressed (CANs previously in development or potential issues) | | |
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| 14 | Material covered in subsequent order | Addressed | IA & IC | IA & IC | Version 5 of the functional model refers to both IA and IC s interchangeably. Until all docs are fixed, they will be treated as the same. |
| 21 | CAN not appropriate vehicle but will hold for future | Addressed | COM-002 | Definition of a Directive | NERC received a request for clarification of the definition of a "directive," whether it applies to both non-emergency and emergency situations, and the required use of three-part communications. |
| 25 | CAN not appropriate vehicle but will hold for future | Addressed | EOP-001 R2.4 | BA Restoration Plans | NERC received the following question: When a BA is not a registered TOP, how does it comply with EOP-001-0 R3.4 (U.S.) or EOP-001-1 R2.4 (Canada), which require BAs to have a set of plans for system restoration? |

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| 32 | Issue too Broad | Addressed | EOP-008<br>TOP-002 | Above and beyond security measures | NERC received a request for clarification regarding whether an entity will be considered non-compliant if the measures it has implemented to comply with the requirement(s) of a standard: 1. meet the intent of the standard and 2. exceed or are superior to the requirement of the standard, 3. but do not meet the actual requirements of a given standard. |
| 36 | Bulletin is a better vehicle to answer | Addressed | PRC-023 | Applicability | This CAN is in regard to PRC-023 and its applicability to Generator Owners that are not also transmission owners and/or distribution providers as stated in FERC Order 733. The requestor asked for clarification on the Effective Date issue because the CAN does not address A.5.1.3 in the Effective Date section of the standard. Section A.5.1.3 establishes that the TO, GO, and DP must comply with R1 "for each facility that is added to the Planning Coordinator's critical facilities list determined |
| 38 | PER-005-1 R3 resolved issue | Addressed | PER-002 R4 | Training Hours | NERC received a request for clarification of how many training hours equals the required five days of training per PER-002 R4. |
| N/A | Bulletin is a better vehicle to answer | Addressed | CIP-007-3/CIP-002-4 | Critical Asset losing its designation | NERC received a request for clarification regarding what is the outcome if a Critical Asset loses its designation, as can be expected when the Bright Line criteria of CIP-002-4, does the asset automatically lose the Critical Cyber Asset designation and no longer applicable to the CIP standards, do you have to conform to CIP-007-3 R7? |
| N/A | Interpretation resolved issue | Addressed | BAL-001 R1<br>BAL-002 | WECC Automatic Time Error Control Procedure | Clarification of whether the WECC Automatic Time Error Control Procedure (WATEC) violates BAL-001-0 R1. Also see Standard's list for clarification "which disturbances are excluded from compliance evaluation." Appendix 2 of BAL-001 states: Interpretation (link: http://www.nerc.com/files/BAL-001-0_1a.pdf)<br>Requirement 1 of BAL-001 — Real Power Balancing Control Performance, is the definition of the area control error (ACE) |
| N/A | CAN not appropriate vehicle | Addressed | Multiple | Intrepretation of BPS definition | Request for clarification on the difference between BPS and BES.<br><br>The definition of BPS is located in Section 215 of Federal Power Act, which states: The term `bulk-power system' means-- `(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion |
| N/A | CAN-0010 addressed issue | Addressed | Multiple | Define Calendar Year and other time periods | If a standard requires the performance of an activity every four calendar years, and an entity performed the activity on January 1, 2008, would the entity meet the standard if the entity performed the activity anytime during 2012? Or would the completion be required on December 31, 2011? |
| N/A | CAN not appropriate vehicle but will hold for future | Addressed | FAC-003 R1.2.2 | IEEE Standard conflicting with NERC standard | According to R1.2.2., "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"… A newer version of this IEEE standard was published in 2009 which contains clearances that are less restrictive than the 2003 version. Would a Transmission Owner be found non-compliant if they adopt the 2009 version, even though the requirement specifically refers to the 2003 version? |
| N/A | AML Corrected | Addressed | BAL-002 R1.1, R3, R3.1, R4, R4.2 | Applicability | Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification. Need to compare standards VRF matrix (link: http://www.nerc.com/page.php?cid=2\|20\|285) with 2012 AML (link: http://www.nerc.com/files/2012%20AML%2010_19_11.xls) for consistency. |
| N/A | AML Corrected | Addressed | BAL-005 R1 | Applicability | Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List |
| N/A | Issue too Broad | Addressed | CIP-002 | CCAs | NERC Compliance received a request for clarification regarding different approaches to compliance and the scope of obligations on entities. |
| N/A | Covered by CAN-0012 and CAN-0010 | Addressed | CIP-005 R4 | Cyber Vulnerability Assessment | NERC Compliance received a request for clarification on whether or not it is it appropriate to enforce this standard as requiring the entity to have performed a CVA prior to their Compliance Date. |
| N/A | AML Corrected | Addressed | COM-001 R6 | Applicability | Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification. |
| N/A | AML Corrected | Addressed | EOP-002 R7.2, R9 | Applicability | Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification. |

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| N/A | Interpretation resolved issue | Addressed | FAC-003<br>MOD-013 | Clarity, consistency of RRO standards and RRO requirements | NERC Compliance received a request for clarity regarding the proper use of RRO. Clarity on the RRO requirements and references in the currently approved NERC standards. 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 |
| N/A | CAN not appropriate vehicle but will hold for future | Addressed | FAC-008 | Submitted Example of Excellence | NERC Compliance received a request for a best practice example of how to approach facility ratings. |
| N/A | AML Corrected | Addressed | FAC-014 R2 and R4 | Applicability | Inadvertent errors between stnds and compliance data sheets and database. |
| N/A | AML Corrected | Addressed | IRO-006 R3 | Applicability | Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification. |
| N/A | Not a CAN - either a Bulletin or Directive | Addressed | Multiple | New Generation Facility | Whether an entity must be registered before connection and any testing |
| N/A | Not a CAN - Registration issue | Addressed | Multiple | Entities that have smaller generator units within the larger facility | Registration issue |
| N/A | Not a CAN - Registration issue | Addressed | PRC-005 | Commissioning Testing/Registration | When will an entity be subject to compliance? Clarify that an entity must be registered before connection and any testing. |
| N/A | Discussed in Bulletin 2011-002 Audit Notifications | Addressed | PRC-008 R2 | Evidence | NERC Compliance received a request for clarification on audit notifications and "data requests" for this standard. |
| N/A | AML Corrected | Addressed | TOP-001 R7.1 | Applicability | Inadvertent errors between stnds and compliance data sheets and database. |
| N/A | AML Corrected | Addressed | TOP-003 R1.2 | Applicability | Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification. |
| N/A | AML Corrected | Addressed | TOP-005 R2 and R3 | Applicability | Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification. |

| CAN Number | Reasoning | Status | Retired or Withdrawn Final CANs | | |
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| 1 | Material covered in subsequent order | Retired | INT-004 R1 | Correction to VRF Matrix | This document provides notice of a correction in the Violation Risk Factor Matrix regarding compliance applicability of INT-004-2 R1. |
| 2 | Material covered in subsequent order | Retired | TOP-003 R1.3 | Correction to VRF Matrix | This document provides notice of a correction in the Violation Risk Factor Matrix and the 2010 Actively Monitored Standards spreadsheet regarding compliance applicability of TOP-003-0 R1.3. |

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| 3 | Material covered in subsequent order | Retired | IRO-006 R2 | Correction to 2010 Actively Monitored Standards spreadsheet | This document provides notice of a correction in the 2010 Actively Monitored Standards spreadsheet regarding compliance applicability of IRO-006-4.1 R2. |
| 4 | Material covered in subsequent order | Retired | IRO-004 R3 | Correction to VRF Matrix and Actively Monitored spreadsheet | This document provides notice of a correction in the Violation Risk Factor Matrix and the 2010 Actively Monitored Standards spreadsheet regarding compliance applicability of IRO-004-1 R3. |
| 16 | NERC CEO High Level Review | Withdrawn | CIP-001 R1 | Non-BES facilities | Is a registered entity required to include non-BES facilities in its Sabotage Reporting Procedure? |

| CAN Number | CAN Requestor | Status | Standard | Topic of CAN | Item Description/Driver for Request<br>(NERC has tried to identify these issues without identifying regions or registered entities; the description is a summary at the time of quarterly prioritization. It may not include all the related information currently identified with each possible CAN; NERC will document other information related to each within that CANs development history. Items listed here may require more than one CAN per standard or a group of similar issues into one CAN, depending on efficiencies, other NERC-wide efforts, etc.) | Last Updated: 6/8/ |
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| **CANs in Development or Final** | | | | | | Related SDT Project o of New/Revised Stan |
| 5 | Regional Entity | Final | CIP-002-3 R3 | Critical Cyber Asset Designation for System Operator Laptops | Registered entities and Regional Entities requested clarity regarding whether system operator laptops with the capability and purpose of controlling Bulk Electric System assets remotely (whether in normal operations or in emergencies) should be designated as Critical Cyber Assets (CCAs). | Project 2010-INT-05 CIP-002-1 t to the operation of a Critical As presented to the NERC Board o 2012. |
| 6 | Regional Entity | Final | EOP-005-1 R7 | Verification of Restoration Procedure | This CAN provides instruction for assessing whether: 1) an entity has verified its restoration procedure "by actual testing or by simulation," as required by EOP-005 R7, and 2) the use of a third-party vendor impacts a registered entity's obligation under the standard. | EOP-005-2 Enforceable 7/1/201 |
| 7 | Registered Entity and Regional Entity | Final | CIP-004-3 R4.2 | Revocation of Access (physical and electronic) to CCAs | Registered entities and Regional entities requested clarity about the extent and timing of revocation of access to Critical Cyber Assets (CCAs) required in CIP-004 R4.2. Specifically, clarity was sought on what constitutes revocation and access (physical and electronic), to CCAs under different entity-specific scenarios. | Project 2008-06 Cyber Security |
| 8 | Registered Entity | Final | PRC-005 R2 | Basis for First Maintenance and Testing Date | NERC Compliance received a request for clarification on PRC-005 R2 regarding the monitored timeframes for gathering evidence pre-June 2007 when determining compliance with an entity's maintenance and testing program. What is the validity of a Regional auditor to ask for evidence pre-June 2007 even though there was no obligation to retain records until at least June 17, 2007? | Project 2007-17 Protection Syst |
| 9 | NERC | Final | FAC-008 R1<br>FAC-009 R1, R2 | Facility Ratings and Design Specifications | This CAN provides instruction for assessing compliance with FAC-008 R1 and FAC-009 R1 when an entity's constructed Facilities do not match its design specifications. | FAC-008-3 Enforceable 1/1/201 |
| 10 | NERC | Final | Multiple | Implementation of "Annual" in NERC Reliability Standard Requirements | This CAN discusses the implementation of annual requirements when the term "annual" is not defined by the standard. | |
| 11 | Regional Entity | Final | PRC-005 R2 | Interval Start Date for New Equipment | NERC Compliance received a request for clarification on PRC-005 R2 regarding gathering evidence of initial testing for new equipment. | Project 2007-17 Protection Syst |
| 12 | Registered Entity and Regional Entity | Final | Requirement of periodic action by Effective Date | Completion of Periodic Activity Requirements During Implementation Plan | Registered entities and Regional entities have requested that NERC provide clarification on whether a registered entity must provide evidence that it completed a periodic action or event required by a NERC Reliability Standard prior to the registered entity's Effective Date for the standard. | |
| 13 | Registered Entity | Final | PRC-023 R1 and R2 | Effective Dates for Switch-On-To-Fault Schemes | This CAN clarifies the Effective Dates for SOTF schemes included on 1) transmission lines operated at 200 kV and above, and 2) transformers with low voltage terminals connected at 200 kV and above, under PRC-023 R1 and R2. | PRC-023-2 has tiered enforceat details |
| 15 | Registered Entity | Final | EOP-002 Attachment 1;<br>EOP-005 R11.3;<br>IRO-002 R4, R5, R6;<br>IRO-003 R1, R2; | Unavailability of NERC Software Tools | NERC Compliance received a request for clarification on a suite of reliability standards that require the use of a NERC tool. What is a registered entity's performance obligation to a standard's requirements when a NERC Tool is unavailable? | EOP-005-2 Enforceable 7/1/201<br>Project 2006-06 Reliability Coor IRO-005) |
| 17 | Regional Entity | Final | CIP-007 R5 | Technical and Procedural System Access and Password Controls | Is a CEA is to verify that technical controls, procedural controls, or both are implemented in assessing compliance with CIP-007 R5? | Project 2012-INT-03 CIP-007 fo |

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| 18 | Registered Entity | Final | FAC-008 R1.2.1 | Terminal Equipment | This CAN provides instruction for assessing what equipment should be considered “terminal equipment” under FAC-008. | FAC-008-3 Enforceable 1/1/201 |
| 19 | Registered Entity | In Development | CIP-007 R3 | Implementation of Software Security Patches | Is a registered entity required to have a technical control for password configuration or would a manual solution meet the requirement? How would a manual solution be audited? When and under what conditions is a TFE is required? | Project 2008-06 Cyber Security |
| 20 | Regional Entity | Final | TPL-002 R1.3, R6, R11<br>TPL-003 R1.3.12<br>TPL-004 | Equipment Outages | NERC received a request for clarification of whether maintenance outages, including Protection Systems, must be included in operational planning studies under TOP-002 or in transmission planning assessments under TPL-002, TPL-003, and TPL-004. | Project 2007-03 – Real-time Op<br>Project 2012-INT-02 TPL-003a &<br>TPL-002-1, TPL-003-1, TPL-004-<br>approval |
| 22 | Registere Entity | Final | VAR-002 R1 | Generator AVR Operation in Alternative Mode | NERC received requests for clarification regarding whether a generator may be operated in manual mode during start-up. | Project 2011-INT-02 Interpretat<br>Constellation Power Gen |
| 23 | Registered Entity | In Development | CIP-005 R3<br>CIP-006 R6<br>CIP-007 R6 | Logging system failures | NERC received a request for clarification of whether any exception exists for an entity that cannot log access 100% of the time, 24 hours per day, seven days per week, and if not, whether the entity needs to file a self-report any time the access logging system fails. | Project 2008-06 Cyber Security |
| 24 | Regional Entity | Final | CIP-002 R3.1 | Routable Protocols and Data Diode Devices | NERC received a request for clarification of whether the communication characteristics of data diode devices can be used to exclude non-critical Cyber Assets from consideration as CCAs when a routable protocol is implemented, thereby making them inapplicable to CIP standards. | Project 2008-06 Cyber Security |
| 26 | Regional Entity | Final | TOP-006 R3 | Protective Relays | NERC received a request for clarification of whether an RC, TOP and BA, under TOP-006 R3, needs to provide appropriate technical information to its operating staff for all protective relays in its area whether or not it has the responsibility or ownership of the protective relays. | Project 2010-INT-01 Interpretat |
| 27 | Regional Entity | Final | TOP-003 R2 | Coordination of Scheduled Outages | NERC received a request to clarify whether TOP-003 R2 requires the BA to plan and coordinate scheduled outages of generators within the BA’s area. | Project 2007-03 – Real-time Op<br>Project 2010-INT-01 Interpretat |
| 28 | Regional Entity | Final | TOP-006 R1.2 | Reporting Responsibilities | This CAN provides instruction for assessing whether a BA or TOP has fulfilled the requirements for reporting transmission or generation resources available for use to RCs and other affected BAs and TOPs under TOP-006 R1.2. | Project 2010-INT-01 Interpretat |
| 29 | Registered Entity | Final | PRC-004 R2 R3 | Protection System Misoperations | NERC received a request for clarification regarding whether entities must develop and implement Corrective Action Plans (CAPs) for, and maintain a record of, all Misoperations or only those that must be reported to NERC/RAPA. | Project 2010-05.1 Phase 1 of Pr<br>Misoperations |
| 30 | Regional Entity | Final | Attestations | Attestations | NERC received a request for clarification regarding the appropriate situations and uses of attestations as evidence of compliance with a reliability standard. | |
| 31 | Regional Entity | Final | CIP-005<br>CIP-006<br>CIP-006 R1.1 | Acceptable Opening Dimensions | NERC received a request to define the entry point metric definition of the access points on the perimeter. NERC also received a request for clarification for an acceptable entry point into a Physical Security Perimeter (PSP) of CCAs, as well as acceptable opening dimensions. | Project 2008-06 Cyber Security |
| 33 | Registered Entity | In Development | PRC-023 R1.1, R1.6, R1.7, R1.8, R1.9 | Transmission Relay Loadability | NERC Compliance received a request for clarity on: load remote to system; generation remote to load; if there is a 4-hour load rating or can a seasonal facility rating be used for R1.1 Furthermore, in a Directional Comparison Blocking (DCB) Scheme, does the reverse looking zone need to comply with PRC-023 loadability requirements? | Project 2010-13.2 Generator Re<br>PRC-023-2 has tiered enforceab<br>details |
| 34 | Regional Entity | In Development | EOP-002 R1<br>IRO-001 R3<br>TOP-001 R1 | Use of Authority Letters | NERC received a request to clarify what criteria auditors consider when reviewing an authority letter. | Project 2006-06 Reliability Coor |

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| 37 | Registered Entity | In Development | Enforcement Process | Aggregation of Violations | NERC received a request for clarification regarding whether the finding of non-compliance of one requirement would be applied across other standards to which that requirement applies. | |
| 39 | NERC | Final | DOE 417 | Filing DOE Form OE-417 Event Reports | The Department of Energy's (DOE) new online process for submitting the OE-417 disturbance reporting form does not automatically issue a copy to NERC or the Regions. | Project 2009-01 Disturbance an |
| 40 | NERC | Final | BAL-003 R2 | Frequency Bias Calculation | NERC received a request for clarification on the proper approach to determine Frequency Bias Setting. | Project 2007-12 Frequency Res |
| 42 | NERC | In Development | PRC-001 R1, R2, R4 | System Protection Coordination | NERC received a request to clarify what types of evidence is required to demonstrate that system protection is coordinated among applicable entities under PRC-001. | Project 2007-06 System Protect |
| 43 | NERC | Final | PRC-005 R2 | Protection System Maintenance and Testing Evidence | NERC received requests for clarification on what types of evidence are typically used to demonstrate compliance with Protection Systems maintenance and testing in certain compliance areas. | Project 2007-17 Protection Syst |
| 44 | NERC | In Development | TOP-001 R1, R2, R5, R8 | Operating Emergencies and Emergency Conditions | NERC received a request for clarification on the definition of emergency, operating emergency and system emergency as used in TOP-001. There are several references to the word emergency in TOP-001, but none of those references are capitalized to indicate a glossary term. | Project 2007-03 – Real-time Op |
| 45 | CEAs<br>Registered Entity | In Development | COM-001 R1.1-R1.4 | Telecommuncation Redundancy | Is a single point of failure an automatic failure to comply with R1.1 - 1.3. If a facility is not sufficiently redundant, is an entity automatically out of compliance with all R1 sub requirements but only R1.4? How does a CEA determine in what situations facilities must be redundant and diversely routed? How do the CEAs assess whether the facilities are redundant (i.e. how far back in the provider system do you go)? | Project 2006-06 Reliability Coor |
| 46 | Registered Entity | In Development | CIP-007-3 | Whether USB-only printers are considered Cyber Assets | Is a USB-only printer a Cyber Asset, or is it only a peripheral device? The term "printer" also needs to be clarified for compliance purposes. What is considered peripheral and what is considered serial.<br><br>The Glossary definition of a Cyber Asset is: "Programmable electronic devices and communication networks including | Project 2008-06 Cyber Security |
| 47 | Registered Entity | In Development | CIP-004 R3.1 | Criminal background checks | Clarification regarding the use of criminal history checks conducted by the FBI in support of the Access Authorization process mandated by the US Nuclear Regulatory Commission. Many companies rely on this process to support their CIP Personnel Risk Assessments (PRA) conducted under the CIP-004 standard. We think a CAN addressing the acceptability of this practice would help provide clarity to the process. | Project 2008-06 Cyber Security |
| 48 | NERC | In Development | EOP Standards | Evidence of communication capability, access and verification under the EOP Standards | NERC Compliance received a request for clarification regarding what evidence a CEA will verify to determine compliance in regard to communication, capability and access using NERC software tools. (RCIS, WECCnet) | EOP-001-1, EOP-005-2, EOP-00 |
| 49 | Registered Entity | In Development | TPL-002 R1.3.10<br>TPL-003 R1.3.10<br>TPL-004 R1.3.7 | Power flow models and protection systems include relay devices as N-1 | Clarification requested on whether the inclusion of redundant and backup protective system failures is required in power flow models. | Project 2012-IN-02 TPL-003-0a<br>TPL-002-1, TPL-003-1, TPL-004-<br>Approval |
| 50 | NERC | In Development | PER-002-0<br>PER-003-0<br>PER-005-1 | Certification of Remote Operators | Which control center operators, remote or local or both, need to be NERC-certified system operators to be in compliance with PER-002 and PER-003? One position states that if an operator is performing (or sending an associated directive to field personnel to perform) an activity within one of the certified functions (being BA, TOP, or RC) the operator must be certified regardless of being remote or local. Also verify types of evidence to verify for PER-002. | PER-003-1 Enforceable 10/1/20<br>PER-005-1 R1 & R2 Enforceable<br>PER-005-1 R3 Enforceable 4/1/<br>PER-005-1 R3.1 Enforceable 4/1 |
| 51 | Registered Entity | In Development | CIP-002-3 | CCA designation of management console for virtual machine (VM) technology | With the Management Console having the capabilities for impacting the CCA VM Client, the Management Console should be considered a CCA. With the expanded usage of Virtual Machine technology it is in the best interest of the industry to have this clearly outlined to make sure the overall reliability of the BES is maintained. | Project 2008-06 Cyber Security |
| 52 | Registered Entity | In Development | FAC-003 R1 | TVMP Changes | NERC received multiple requests for clarification on FAC-003-1 R1 regarding the allowable timeframe for implementation when an entity changes one TVMP plan based on normal trend to another TVMP plan based on clear cut. Once changed is the entity bound to implement immediately? Does the standard provide for entities to have a transition period while changing TVMP plans? | FAC-003-2 Adopted by NERC Bc<br>pending regulatory approval |

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| 53 | Registered Entity | In Development | TOP-002 R2, R6, R8, R10, R11, R19 | System Conditions | R6: What is the responsibility of the BA to plan to meet CPS and DCS under unscheduled changes in the system configuration and generation dispatch? R2, R8, and R19: Clarity on BA obligations; the request for clarity seems to try to change the standard. R6 and R10: BA and TOP applicability to the standard. | Project 2007-03 Real-time Oper |

| Prioritized CANs | Source | Status | Standard | Topic of CAN | Item Description/Driver for Request<br>**(NERC has tried to identify these issues without identifying regions or registered entities; the description is a summary at the time of quarterly prioritization. It may not include all the related information currently identified with each possible CAN; NERC will document other information related to each within that CANs development history. Items listed here may require more than one CAN per standard or a group of similar issues into one CAN, depending on efficiencies, other NERC-wide efforts, etc.)** | Related SDT Project of New/Revis |
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| **MEDIUM** | Registered Entity | Prioritized | EOP-003 R3 & R5 | Applicability of BA or TOP to automatic load shedding or manual load shedding | NERC Compliance received a request for clarity regarding the BA and TOP applicability with regard to compliance with the EOP-003. Also, does this apply only to automatic load shedding or does it also apply to manual load shedding?<br><br>Project 2007-01 was approved by the NERC Board of Trustees on November 4, 2010 and is pending regulatory approval. | EOP-003-2 Adopted by NERC Bo pending regulatory approval |
| **MEDIUM** | Registered Entity | Prioritized | FAC-014 R5 | Responsibility for SOLs and IROLs | Clarification is needed to demonstrate that each applicable function is responsible for establishing SOLs and IROLs regardless of whether the registered entity is included in the studies performed by an RC or PA.<br>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: | Project 2006-06 Reliability Coor |
| **MEDIUM** | Registered Entity | Prioritized | IRO-005 R10 | What does the term 'derived limits' mean in general and with regard to small generators? | The confusion with IRO-005-3a R10 is that it is not clear what the auditors would deem to be “derived limits” and what their approach would be to a small generator “…operating the Bulk Electric System.” What is also not clear is how auditors would approach independent entities even becoming aware of derived limits. | Project 2006-06 Reliability Coor |
| **MEDIUM** | NERC | Prioritized | PRC-008 R1<br>PRC-011<br>PRC-017 R1.1 | Does the term "Protection System" include UFLS and UVLS equipment? Also, is control circuitry considered part of an SPS and does that circuitry fall under the definition of a Protection System? What constitutes a Special Protections | Consider defining UFLS equipment as a Protection System or explicitly list what is included as part of UFLS equipment in order to remove confusion concerning this terminology. There is uncertainty as to what equipment is considered part of the Protection System, which has led to inconsistent applications to TOs and DPs with a UFLS Program. Clarify whether PRC-017 R1.1 specifically includes control circuitry as part of an SPS or if SPS falls under the definition of a Protection System. | Project 2007-17 Protection Syst |
| **MEDIUM** | Registered Entity | Prioritized | TOP-002 R14, R16, R17 | Intentional Time Delays notifying BA and RC | Define "Intentional Time Delay" as outlined in TOP-002 R14, R16 and R17.<br><br>TOP-002 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: | Project 2007-03 Real-time Oper |
| **MEDIUM** | Registered Entity | Prioritized | EOP-008-0 R1 | Implementation Plan and Test Drills | 1. Does the requirement to have a plan imply the implementation of that plan?<br><br>2. R1 states that a RC, TOP, and BA must have a plan to continue reliability operations in the event its control center becomesinoperable. R1.1 talks about the contingenct plans must be "viable and R1.5 talks abpout tests or drill "to ensure | EOP-008-1 Enforceable 7/1/201 |
| **MEDIUM** | Registered Entity | Prioritized | PRC-017-0 R1.1 | Maintance and Testing Plans for SPS | R1.1 states that SPS identification shall include but is not limited to: relays, instrumnent transformers, communication systems, and batteries. Does a SPS to fall under the NERC definition of a Protection System? SPS includes control circuitry which would be included in the Protection System maintenance and testing plan. Guidance is requested to clarify what is expected to be addressed in the maintenance plan for a SPS. | Project 2007-17 Protection Syst |
| **LOW** | Registered Entity | Prioritized | CIP-003 R4 and R5 | Protection and access control to CCA information | Clarify whether hashing is an acceptable method for information authentication in order to be in compliance with the requirements for authenticating secure messages. | Project 2008-06 Cyber Security |
| **LOW** | Region | Prioritized | IRO-002 R3 | Applicability of BA and TOP | Clarity requested from a region on the RC, BA, and TOP applicability: What must the BA and TOP do to comply with IRO-002 R3?<br><br>IRO-002 R3 states: Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability Coordinators, for both voice and data exchange as | Project 2006-06 Reliability Coor |
| **LOW** | Registered Entity | Prioritized | Multiple | Mapping of registered entity policies to NERC Standard Requirements | If an entity has one or more policies for any standard to demonstrate/demo how it meets the requirements and sub-requirements how within the policy or policies the CEA is to verify each of the components laid out in the requirement and sub-requirements.<br><br>CAN would cover multiple standards. CAN topic was originally submitted with regard to CIP-002 R1.1. | |
| **LOW** | Registered Entity | Prioritized | MOD-018 R1 | Definition of "non-member entities" | Clarity regarding what is included as a "non-member" as found in MOD-018 R1.<br><br>MOD-018 R1 states: 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: | |

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| **LOW** | Registered Entity | Prioritized | COM-002 R1.1 | Communication Paths and Directives | 1. Does "predetermined communication paths" in R1.1 mean certain operators in the control room rather than facilities peoviding the communication paths? R1.1 states "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 | Project 2006-06 Reliability Coor<br>Project 2007-02 Operating Pers<br>Protocols |
| **LOW** | Registered Entity | Prioritized | EOP-005-1 | Restoration Plan Coordination | 1. Does a GO that does not participate in the blackstart process need to coordinate restoration plans?<br>2. Discussions arose regarding the applicability of this requirement as it relates to long term scheduled equipment outages. Should an entities restoration plan be reviewed and updated for long term scheduled equipment outages as these change the power system network? | EOP-005-2 Enforceable 7/1/201 |

| CAN Number | Reasoning | Status | Issues that have been addressed (CANs previously in development or potential issues) | | |
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| 14 | Material covered in subsequent order | Addressed | IA & IC | IA & IC | Version 5 of the functional model refers to both IA and IC s interchangeably. Until all docs are fixed, they will be treated as the same. |
| 21 | CAN not appropriate vehicle but will hold for future | Addressed | COM-002 | Definition of a Directive | NERC received a request for clarification of the definition of a "directive," whether it applies to both non-emergency and emergency situations, and the required use of three-part communications. |
| 25 | CAN not appropriate vehicle but will hold for future | Addressed | EOP-001 R2.4 | BA Restoration Plans | NERC received the following question: When a BA is not a registered TOP, how does it comply with EOP-001-0 R3.4 (U.S.) or EOP-001-1 R2.4 (Canada), which require BAs to have a set of plans for system restoration? |
| 32 | Issue too Broad | Addressed | EOP-008<br>TOP-002 | Above and beyond security measures | NERC received a request for clarification regarding whether an entity will be considered non-compliant if the measures it has implemented to comply with the requirement(s) of a standard: 1. meet the intent of the standard and 2. exceed or are superior to the requirement of the standard, 3. but do not meet the actual requirements of a given standard. |
| 35 | CAN not appropriate vehicle but will hold for future | Addressed | Periodic Data Submittals | Periodic Data Submittal Violations | NERC received a request for clarification of whether violations would be mitigated if they were included in periodic data submittals. |
| 36 | Bulletin is a better vehicle to answer | Addressed | PRC-023 | Applicability | This CAN is in regard to PRC-023 and its applicability to Generator Owners that are not also transmission owners and/or distribution providers as stated in FERC Order 733. The requestor asked for clarification on the Effective Date issue because the CAN does not address A.5.1.3 in the Effective Date section of the standard. Section A.5.1.3 establishes that the TO, GO, and DP must comply with R1 "for each facility that is added to the Planning Coordinator's critical facilities list determined |
| 38 | PER-005-1 R3 resolved issue | Addressed | PER-002 R4 | Training Hours | NERC received a request for clarification of how many training hours equals the required five days of training per PER-002 R4. |
| 41 | IRO-004-2 resolved issue | Addressed | IRO-004 R1 | Dynamic Modeling in a Next-Day Assessment | NERC received a request for clarification on whether complete dynamic modeling is required for next-day assessments. |
| N/A | Bulletin is a better vehicle to answer | Addressed | CIP-007-3/CIP-002-4 | Critical Asset losing its designation | NERC received a request for clarification regarding what is the outcome if a Critical Asset loses its designation, as can be expected when the Bright Line criteria of CIP-002-4, does the asset automatically lose the Critical Cyber Asset designation and no longer applicable to the CIP standards, do you have to conform to CIP-007-3 R7? |
| N/A | CAN not appropriate vehicle | Addressed | PRC-004 | Consistent reporting of protection system Misoperations | Project 2010-05.1 Protection Systems (Misoperations) addresses this issue. Clarify the audit scope for Misoperations and CAPs to be reviewed. Request clarification as to whether non-reportable Misoperations are subject to compliance audits. Recommendation that an audit can cover any time and any action within the audit period regardless of reportability of misoperations. Also, does operation of a relay during an abnormal condition constitute a misoperation under PRC-004? |
| N/A | CAN not appropriate vehicle | Addressed | TPL-003-0 | Application of TPL-003 Table 1 | Application of Table 1 in TPL-003 and proper modeling of contingency events (ie: Category C vs. D). Confusion about what is an extreme event and misunderstanding of categorizing simulations (found in Table 1 of the TPL standards) on the final outcome after the fault was cleared instead on the initiating event/fault as required. |

| | | | | | |
|---|---|---|---|---|---|
| N/A | CAN not appropriate vehicle | Addressed | Multiple | Definition of radial transmission | Source documents from multiple regions and from NERC demonstrate the inconsistent application of "radial." |
| N/A | Interpretation resolved issue | Addressed | BAL-001 R1<br>BAL-002 | WECC Automatic Time Error Control Procedure | Clarification of whether the WECC Automatic Time Error Control Procedure (WATEC) violates BAL-001-0 R1. Also see Standard's list for clarification "which disturbances are excluded from compliance evaluation." Appendix 2 of BAL-001 states: Interpretation (link: http://www.nerc.com/files/BAL-001-0_1a.pdf)<br>Requirement 1 of BAL-001 — Real Power Balancing Control Performance, is the definition of the area control error (ACE) |
| N/A | CAN not appropriate vehicle | Addressed | Multiple | Intrepretation of BPS definition | Request for clarification on the difference between BPS and BES.<br><br>The definition of BPS is located in Section 215 of Federal Power Act, which states: The term `bulk-power system' means-- `(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion |
| N/A | CAN-0010 addressed issue | Addressed | Multiple | Define Calendar Year and other time periods | If a standard requires the performance of an activity every four calendar years, and an entity performed the activity on January 1, 2008, would the entity meet the standard if the entity performed the activity anytime during 2012? Or would the completion be required on December 31, 2011? |
| N/A | CAN not appropriate vehicle but will hold for future | Addressed | FAC-003 R1.2.2 | IEEE Standard conflicting with NERC standard | According to R1.2.2., "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"… A newer version of this IEEE standard was published in 2009 which contains clearances that are less restrictive than the 2003 version. Would a Transmission Owner be found non-compliant if they adopt the 2009 version, even though the requirement specifically refers to the 2003 version? |
| N/A | AML Corrected | Addressed | BAL-002 R1.1, R3, R3.1, R4, R4.2 | Applicability | Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification. Need to compare standards VRF matrix (link: http://www.nerc.com/page.php?cid=2\|20\|285) with 2012 AML (link: http://www.nerc.com/files/2012%20AML%2010_19_11.xls) for consistency. |
| N/A | AML Corrected | Addressed | BAL-005 R1 | Applicability | Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List |
| N/A | Issue too Broad | Addressed | CIP-002 | CCAs | NERC Compliance received a request for clarification regarding different approaches to compliance and the scope of obligations on entities. |
| N/A | Covered by CAN-0012 and CAN-0010 | Addressed | CIP-005 R4 | Cyber Vulnerability Assessment | NERC Compliance received a request for clarification on whether or not it is it appropriate to enforce this standard as requiring the entity to have performed a CVA prior to their Compliance Date. |
| N/A | AML Corrected | Addressed | COM-001 R6 | Applicability | Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification. |
| N/A | AML Corrected | Addressed | EOP-002 R7.2, R9 | Applicability | Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification. |
| N/A | Interpretation resolved issue | Addressed | FAC-003<br>MOD-013 | Clarity, consistency of RRO standards and RRO requirements | NERC Compliance received a request for clarity regarding the proper use of RRO. Clarity on the RRO requirements and references in the currently approved NERC standards. 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 |
| N/A | CAN not appropriate vehicle but will hold for future | Addressed | FAC-008 | Submitted Example of Excellence | NERC Compliance received a request for a best practice example of how to approach facility ratings. |
| N/A | AML Corrected | Addressed | FAC-014 R2 and R4 | Applicability | Inadvertent errors between stnds and compliance data sheets and database. |

| | | | | | |
|---|---|---|---|---|---|
| N/A | AML Corrected | Addressed | IRO-006 R3 | Applicability | Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification. |
| N/A | Not a CAN - either a Bulletin or Directive | Addressed | Multiple | New Generation Facility | Whether an entity must be registered before connection and any testing |
| N/A | Not a CAN - Registration issue | Addressed | Multiple | Entities that have smaller generator units within the larger facility | Registration issue |
| N/A | Not a CAN - Registration issue | Addressed | PRC-005 | Commissioning Testing/Registration | When will an entity be subject to compliance? Clarify that an entity must be registered before connection and any testing. |
| N/A | Discussed in Bulletin 2011-002 Audit Notifications | Addressed | PRC-008 R2 | Evidence | NERC Compliance received a request for clarification on audit notifications and "data requests" for this standard. |
| N/A | AML Corrected | Addressed | TOP-001 R7.1 | Applicability | Inadvertent errors between stnds and compliance data sheets and database. |
| N/A | AML Corrected | Addressed | TOP-003 R1.2 | Applicability | Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification. |
| N/A | AML Corrected | Addressed | TOP-005 R2 and R3 | Applicability | Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification. |

| CAN Number | Reasoning | Status | Retired or Withdrawn Final CANs | | |
|---|---|---|---|---|---|
| 1 | Material covered in subsequent order | Retired | INT-004 R1 | Correction to VRF Matrix | This document provides notice of a correction in the Violation Risk Factor Matrix regarding compliance applicability of INT-004-2 R1. |
| 2 | Material covered in subsequent order | Retired | TOP-003 R1.3 | Correction to VRF Matrix | This document provides notice of a correction in the Violation Risk Factor Matrix and the 2010 Actively Monitored Standards spreadsheet regarding compliance applicability of TOP-003-0 R1.3. |
| 3 | Material covered in subsequent order | Retired | IRO-006 R2 | Correction to 2010 Actively Monitored Standards spreadsheet | This document provides notice of a correction in the 2010 Actively Monitored Standards spreadsheet regarding compliance applicability of IRO-006-4.1 R2. |
| 4 | Material covered in subsequent order | Retired | IRO-004 R3 | Correction to VRF Matrix and Actively Monitored spreadsheet | This document provides notice of a correction in the Violation Risk Factor Matrix and the 2010 Actively Monitored Standards spreadsheet regarding compliance applicability of IRO-004-1 R3. |
| 16 | NERC CEO High Level Review | Withdrawn | CIP-001 R1 | Non-BES facilities | Is a registered entity required to include non-BES facilities in its Sabotage Reporting Procedure? |

**From:** NERC Compliance Operations Announcements (Do Not Reply)
**To:** canonly
**Subject:** NERC Announcement: Activity on Compliance Website
**Date:** Friday, June 08, 2012 1:43:29 PM
**Importance:** High

# NERC Compliance Announcement

## The following activity has taken place on the Compliance site:

### Compliance Process Bulletin has been posted as Final:

- Bulletin #2012-001 Applicability of PRC-023 for Generator Owners

This bulletin was developed in response to a registered entity's request for clarification about FERC Order No. 733 and FERC Order No. 733-A, regarding the applicability of PRC-023-1 to Generator Owners that are not also registered as Distribution Providers or Transmission Owners.

### DRAFT Compliance Application Notices (CANs) Posted for Industry Comment:

- CAN-0033 PRC-023 Transmission Relay Loadability Criteria Selection, Facility Rating Selection, and Applicability to Specific Protection Functions
- CAN-0044 TOP-001 Operating Emergencies and Emergency Conditions

The above CANs are posted for the 21-day industry comment period under the "Draft CANs for Industry Review" section of the CAN website. These CANs were provided to the NERC committees (OC, PC, CIPC, SC and CCC) for initial comments; however, committee comments reflected in the draft CANs may be not represent the opinion of the entire committee. Please provide comments on these topics by completing the CAN Comment Form and sending it to cancomments@nerc.net on or before **June 29, 2012**.

### CAN Status Spreadsheet has been updated

The CAN spreadsheet has also been updated to show the status of new CANs in development, which were determined to be high priority issues based on feedback from NERC committees and registered entities. The status and priority spreadsheet has also been updated to include the sources of the CAN issues. As a reminder, CANs labeled as "in development" will be posted for industry comment after the NERC committees have reviewed the initial drafts. To view the CAN status and priority list, click here.

### CAN-0041 has been removed from development process

CAN-0041 addressed whether dynamic modeling is required for next-day assessments under IRO-004-1, which was resolved in the new version of this standard, IRO-004-2 (enforceable October 1, 2011). This CAN has been removed from the NERC website and is documented

under the “issues that have been addressed” section in the CAN Priority List spreadsheet.

## Industry Comments have been Posted

NERC has posted industry comments of DRAFT CAN-0019 and DRAFT CAN-0023 on the CAN website, located under the “Industry Comments” section.

## Announcing a New Compliance Operations Email Address

All major NERC compliance communication will now be issued from a new email address, NERC Compliance Operations Announcements (Do Not Reply), rather than from individual NERC staff members’ email addresses. This change will allow stakeholders to more easily sort and search for announcements issued from NERC’s compliance department. While the email address will be a “do not reply” address, all announcements will include information about whom to contact with questions, along with a hyperlink that pre-populates an email to the appropriate NERC staff member.

For more information regarding Compliance Application Notices, please contact Ben Engelby at 404-446-2578.

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**To:** canonly
**Subject:** NERC Announcement: Activity on Compliance Website
**Date:** Friday, June 08, 2012 1:43:29 PM
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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# NERC Compliance Process Bulletin #2012-001

Applicability of PRC-023 for Generator Owners

Posted: June 8, 2012

## Background

NERC received a request for clarification regarding the applicability of PRC-023 for Generator Owners (GOs) that are not also registered as Transmission Owners (TOs) or Distribution Providers (DPs). As stated in FERC Order No. 733, GOs that are not also registered as TOs or DPs are not subject to compliance with PRC-023.

FERC Order No. 733 states, in pertinent part:

> 342. Reliability Standard PRC-023-1 applies to Transmission Owners, Generator Owners, and Distribution Providers with load-responsive phase protection systems as described in attachment A of the Reliability Standard, applied to facilities defined in requirements 4.1.1 through 4.1.4.[221] The Reliability Standard applies to facilities 100 kV and above and to transformers with low-voltage terminals 200 kV and above. Because there are no commercial generators with a terminal voltage as high as 100 kV and all generator step-up and auxiliary power transformers have low-voltage windings well below 200 kV, PRC-023-1 excludes generators and all generator step-up and auxiliary transformers. **Therefore, no generator owner that is not also a transmission owner and/or a distribution provider will be subject to PRC-023-1**. Accordingly, the Commission calculates that the potential applicability of the Final Rule may be reduced by 623, which is the total number of entities registered solely as a generator owner. Thus, the Commission anticipates that the Final Rule will apply to approximately 678 entities overall.[222] [emphasis added]

[221] As proposed, the Commission notes PRC-023-1 is applicable to Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4., however, excludes generator protection relays that are susceptible to load in Section (3) of Attachment A.

[222] The Commission derives this result by using the following equation: 1301 applicable entities (entities registered as one of more of the following functions: Distribution Provider, Transmission Owner, Generator Owner, and Planning Authority) – 623 entities registered solely as a Generator Owner = 678.

FERC's statement was confirmed in Order No. 733-A as follows:

> The Commission stands by its statement, as found in the Final Rule, "no generator owner that is not also a transmission owner and/or a distribution provider will be subject to PRC-023-1. Accordingly, the Commission was correct in limiting the number of entities that could be subject to PRC-023-1."[1]

**Explanation of Issue**

Based on the statements in FERC Order No. 733 and 733-A, GOs that are not also registered as TOs or DPs are not subject to compliance with PRC-023.

Regional Entities should consider whether GOs that are not also registered as TOs or DPs meet the criteria for registration under these functions using a risk-based methodology.

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*This document is designed to convey compliance guidance from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time.*


[1] FERC Order No. 733-A at P. 141.

**From:** NERC Compliance Operations Announcements (Do Not Reply)
**To:** canonly
**Subject:** NERC Announcement: Activity on Compliance Website
**Date:** Friday, June 15, 2012 5:39:55 PM
**Importance:** High

# NERC Compliance Announcement

## The following activity has taken place on the Compliance site:

### Revised Compliance Application Notices (CANs) Posted as Final

The following CANs have been revised to align with the NERC CEO High Level Review of CAN-0008.

- CAN-0011 PRC-005 R2 Interval Start Date for New Equipment (Revised)
- CAN-0012 Completion of Periodic Activity Requirements During Implementation Plan (Revised)

### Industry Comment Period has been Extended for Draft CANs

- Draft CAN-0033 PRC-023 Transmission Relay Loadability Criteria Selection
- Draft CAN-0044 TOP-001 Operating Emergencies and Emergency Conditions

The industry comment period has been extended for the above Draft CANs. Please submit the CAN Comment Form to cancomments@nerc.net on or before **July 9, 2012**.

### Announcing a New Compliance Operations Email Address

All major NERC compliance communication will now be issued from a new email address, NERC Compliance Operations Announcements (Do Not Reply), rather than from individual NERC staff members' email addresses. This change will allow stakeholders to more easily sort and search for announcements issued from NERC's compliance department. While the email address will be a "do not reply" address, all announcements will include information about whom to contact with questions, along with a hyperlink that pre-populates an email to the appropriate NERC staff member.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Compliance Monitoring and Enforcement Program

## 2011 Annual Report

April 1, 2012

RELIABILITY | ACCOUNTABILITY






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# Executive Summary

This report provides details, analysis, lessons learned, and forward-looking activities regarding the Electric Reliability Organization's (ERO) implementation of the Compliance Monitoring and Enforcement Program (CMEP) in 2011. The information for this report was collected from the eight Regional Entities (RE) and North American Electric Reliability Corporation (NERC) staff. Specific areas where information was received from NERC staff include the Compliance Operations department's Audit Assurance and Oversight (AAO), Compliance Interface and Outreach, and Organization Registration and Certification groups, the Reliability Risk Management department's Event Analysis (EA) and Investigation Teams and Human Performance groups, the Standards Development group, the Compliance Enforcement department, the Critical Infrastructure Department, and the Legal and Regulatory department. In early 2012, the REs provided NERC information about their programs via a survey

## NERC Staff CMEP Activities

The NERC staff's CMEP activities included the initial steps undertaken to ensure that NERC's risk-based approach was interated in an effective and efficient manner within NERC's Compliance Operations and Compliance Enforcement departments in 2011. The specific challenges and accomplishments faced by NERC staff are described as follows:

- NERC, with input from the REs, continued to use and develop Compliance Application Notices (CANs). The purpose of the CAN is to create consistency regarding how compliance is being assessed in the field. In 2011, 25 final CANs were posted on the NERC website and four CANs were retired.[1]
- NERC, with input from the REs, released four Compliance Application Reports (CARs). CARs provide a thorough analysis of reliability standards that have a high frequency of violations, in order to help registered entities and REs understand why certain standards are so frequently violated. Additionally, based upon analysis of these violations, lessons learned are provided to aid the industry in compliance.[2]
- NERC issued seven Public Notices in order to provide additional compliance information on a variety of issues. Of particular note, was the Transfer of Assets and Deployment of New Assets bulletin. It clarified the effects of bulk power system (BPS) asset transfers or deployment of new BPS assets, as they relate to a registered entity's responsibility for compliance with the applicable NERC Reliability Standards, upon taking possession or commencing operation of these assets.[3]
- NERC conducted a Key Reliability Standard Spot Check (KRSSC) Program to analyze and promote the consistency of the REs audit approaches with the reliability standards. PRC-005 was the first reliability standard selected in 2011 to evaluate the RE audit approaches.[4] The KRSSC Program will be used to inform the standards development

[1] Compliance Applications Notices are located at: http://www.nerc.com/page.php?cid=3%7C22%7C354

[2] Compliance Analysis Reports are located at: http://www.nerc.com/page.php?cid=3|329

[3] Public Notices are located at: http://www.nerc.com/page.php?cid=3|22

[4] KRSSC of PRC-005 information located at: http://www.nerc.com/files/PRC-005-1%20KRSSC%20Final%20Report-%2009142011.pdf

process of needed areas for improvements in terms of compliance monitoring and used in any revised audit approaches as related to the Reliability Standards Audit Worksheets (RSAWs).

- NERC, with input from the REs, developed a new Administrative Citation Notice of Penalty format that was used during the first eight months of 2011. The Administrative Citation Notice of Penalty format was discontinued as a result of the Compliance Enforcement Initiative. Two new formats for reporting the disposition of Possible Violations were utilized beginning in September 2011. These included the Spreadsheet Notice of Penalty (NOP) format and the Find, Fix, Track and Report (FFT) spreadsheet format.[5] The key objective of the Compliance Enforcement Initiative (CEI) is to align ERO processing of Possible Violations (PVs) to the level of risk posed to the reliability of the BPS.[6]
- In order to enhance and develop the technical and auditing capabilities of Compliance Enforcement Authority (CEA) staff, NERC conducted four Lead Auditor training sessions and two CIP Standards training sessions for auditors. Additionally, ERO staff (NERC and the REs) completed two ERO CEA staff workshops. The purpose of these workshops was to provide auditors with CMEP information and updates and to ensure consistency in the application of the program across the industry.[7]
- NERC staff attended and made presentations at 18 RE compliance workshops to provide guidance to registered entities and to receive information that can be used to improve the CMEP going forward.
- NERC processed two appeals[8] and certified 10 registered entities, bringing the NERC Compliance Registry to a total of 1,914 registered entities that are registered for 4,722 functions.[9] The registration and certification process ensures that those entities that have material impact on the BPS are properly registered as a user, owner, or operator of the BPS.

## Regional Entities CMEP Activities

REs were asked to provide insight into their compliance monitoring, outreach, and enforcement programs, effectiveness of their CMEP, events analysis and compliance review processes, and to describe the metrics they are using and where they see their programs in the future. Each of these issues is addressed in turn below:

- The REs reported that self-identified violations, i.e. those identified through self-reports and self-certifications, continue to be the leading method in which PVs are identified. Self-identified discovery methods accounted for 67% of all violations discovered in 2011, which is a slight increase from the 65% recorded in 2010. This continuing trend demonstrates the growth and maturity of internal controls within registered entities' compliance programs throughout the industry.

[5] *See* the searchable Find, Fix, Track and Report (FFT) spreadsheet at: http://www.nerc.com/filez/enforcement/index.html
[6] Filing of Compliance Enforcement Initiative is located at: http://www.nerc.com/page.php?cid=1|9|170
[7] ERO auditor training information is located at: http://www.nerc.com/page.php?cid=3|23|378
[8] Decisions on Appeals are located at: http://www.nerc.com/page.php?cid=3|25|172
[9] Organization Certification information is located at: http://www.nerc.com/page.php?cid=3|25|294

- Several REs reported that improved data transmission processes between the audit team and registered entity have resulted in a significant reduction to the man-hours required to complete an audit.
- Each RE reported that the use of metrics have been very valuable. The most common metrics being monitored include: tracking of audits, spot checks, Notice of Violations, mitigation plans, budgeting constraints, and resource planning. Going forward, the ERO Compliance and Enforcement Management Group (ECEMG) has taken on the project of ensuring and improving metric consistency between the REs.
- The newly instituted Actively Monitored List (AML) tiered approach is being found as beneficial in that the process identifies those standards and requirements that have a direct impact on the reliability of the BPS reducing audit scope and ultimately lowering audit burden.[10]
- The Administrative Citation Notice of Penalty process and subsequently the CEI FFT and new NOP formats brought efficiency gains to the REs. The FFT process ensures all PVs are addressed and helps focus resources on those risks that have the greatest impact to reliability of the BPS, thereby advancing NERC's risk based approach to each regional CMEP.
- The eight REs reported that they completed all scheduled 2011 audits, representing 451 compliance audits of registered entities.[11]
- The eight REs reported that they were on track for a timely completion of their six year audit cycles.
- In 2011, REs conducted a total of 26 compliance seminars and workshops reaching out to approximately 4,365 participants and developed newsletters and several other forms of outreach to the industry.
- REs reported that registered entities completed 303 event analysis self-assessments in 2011.

## Significant 2011 Projects

NERC pursued several significant projects throughout 2011. These projects have had the primary focus of streamlining and more closely associating CMEP efforts to a risk-based process such that identified areas of BPS reliability risk are those that have the greatest time and effort dedicated to them. The ERO activities that have been developed at NERC and implemented by the REs and NERC to realize this goal are described as follows:

- As directed by FERC, in 2011, NERC formally defined the Bulk Electric System (BES) to ensure consistency between the REs and clarity of components contained therein.[12] The filing is pending at the Commission. This could limit the facilities that are subject to NERC Reliability Standards and therefore have an impact on compliance monitoring processes.

[10] 2011 Actively Monitored Reliability Standards list is located at: http://www.nerc.com/commondocs.php?cd=3

[11] One audit with a non-FERC jurisdictional entity was postponed for one year.

[12] Details on defining the Bulk Electric System can be found at: http://www.nerc.com/filez/standards/Rules_of_Procedure-BES.html

- A significant change in the paradigm for monitoring and enforcing compliance with reliability standards was set into motion in 2011 with the FFT process. After several years of experience with the current program, FERC agreed that NERC and the Regional Entities should have the flexibility to more efficiently process and track lesser risk violations in order to focus their resources on issues that pose the greatest risk to reliability.[13]
- NERC and the Regional Entities began work on a registered entity assessment template. This assessment is being developed to establish a consistent basis for appropriately scoping compliance monitoring, to provide an opportunity for Regional Entities to work with registered entities on reliability efforts, and for registered entities to showcase their reliability efforts.
- To create a proactive focus on reducing human error and those precursory factors that allow human error to impact system reliability and to lower externally identified violations, NERC initiated a human performance program.
- To allow a registered entity to better analyze enforcement data, the Compliance Enforcement department developed the NOP searchable spreadsheet.[14] This tool provides a means for any entity to quickly compare and contrast ERO-wide data with regards to penalty specifics.
- The CAN process was revised to clarify that a CAN provides instructions to CEA staff regarding compliance assessments of registered entities with applicable reliability standard requirements. Additionally, the process was revised to include a high level of review mechanism to address concerns raised with a given CAN.[15]
- In response to a number of registered entities within the Western Interconnection, NERC granted time for all entities subject to the Rated System Path Methodology standard MOD-029-1a requirement (R) 2.1.
- NERC incorporated a stronger focus on risk-based and performance-based criteria into the ERO audit approach for 2012 in the August 2011 AML revision.[16]
- To foster consistency across the REs, NERC held two ERO auditor workshops for CEA Staff in 2011. The purpose of the ERO CEA Workshops is: 1) to increase the competency level of the CEA Staff and 2) to improve consistency in the application of the CMEP across the ERO. The workshops included presentations, panel discussions, and breakout work sessions, which provided CEA staff the opportunity for interactive involvement and continuing training.[17]

[13] See the searchable Find, Fix, Track and Report (FFT) spreadsheet at: http://www.nerc.com/filez/enforcement/index.html

[14] See the searchable Notice of Penalty spreadsheet at: http://www.nerc.com/filez/enforcement/Searchable_Enforcement_Page_03052012.xlsx

[15] The CAN process procedure can be found at: http://www.nerc.com/files/CAN%20Process%20Version%205.pdf

[16] See 2011 Actively Monitored Reliability Standards at: http://www.nerc.com/commondocs.php?cd=3

[17] See NERC ERO Auditor Training page at: http://www.nerc.com/page.php?cid=3|23|378

# Acknowledgement

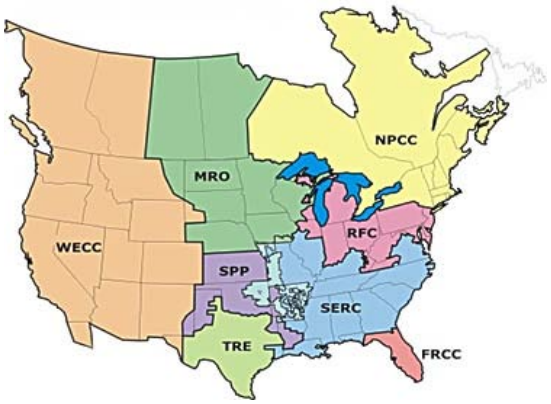
This report is the fifth annual report since NERC Reliability Standards became mandatory and enforceable in the United States (these reliability standards are mandatory in some Canadian provinces). An annual report is developed following the conclusion of the program at each year end, allowing for the evaluation of program activities for a complete year. NERC collects this information from the REs in the first quarter and develops a draft report for review by the REs, the Compliance and Certification Committee (CCC), and the Board of Trustees Compliance Committee (BOTCC).

# Introduction

This report describes the results and effectiveness of the 2011 ERO CMEP as implemented by the eight REs through the Regional Delegation Agreements (RDA) and as overseen by NERC. FERC Order No. 672[18] provides the framework for an ERO and its corresponding certification process. On July 20, 2006, FERC certified NERC as the ERO.[19] FERC regulations provide that an ERO must submit an assessment of its performance three years from the date of certification by the Commission, and every five years thereafter. On September 16, 2010, FERC issued an order on NERC's three year performance assessment. Among other things, the Commission accepted "the performance assessment of NERC as the ERO, and the REs, and [found] that they continue to satisfy the statutory and regulatory criteria for certification."[20]

On April 19, 2007, FERC approved eight RDAs[21] through which NERC, as the international ERO, delegates certain compliance monitoring and enforcement activities ensuring that users, owners, and operators of the BPS in the United States comply with Commission-approved, mandatory reliability standards. In 2010, NERC negotiated modifications to the delegation agreements. The Commission-approved delegation agreements and associated orders by the Commission cover all aspects of the relationships between NERC and the REs, and provide an effective tool for oversight by NERC of the Regional programs and for managing those relationships. These REs include:

- Florida Reliability Coordinating Council, Inc. (FRCC)
- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council, Inc. (NPCC)
- Reliability*First* Corporation (RFC)
- SERC Reliability Corporation (SERC)
- Southwest Power Pool Regional Entity (SPP RE)
- Texas Reliability Entity, Inc. (Texas RE)
- Western Electricity Coordinating Council (WECC)




The entities registered by the REs come from all segments of the electric industry including: investor-owned utilities, federal power agencies, rural electric cooperatives, state, municipal and provincial utilities, independent power producers, power marketers, and load-serving

[18] See *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 at P 31 (2006) at: http://www.nerc.com/files/20060720_ERO_certification.pdf

[19] *Id.* at P 3

[20] See *Order on the Electric Reliability Organization's Three-Year Performance Assessment*, 132 FERC ¶ 61,217 at P 1 (2010) at: http://www.nerc.com/files/Order_on_NERC_Three_Year_Assessment.pdf

[21] *North American Electric Reliability Council, et. al.,* Order Accepting ERO Compliance Filing, Accepting ERO/Regional Entity Delegation Agreements, and Accepting Regional Entity 2007 Business Plans, 119 FERC ¶ 61,060 (2007). The RDAs can be found on the NERC website at: http://www.nerc.com/page.php?cid=1|9|119|181

entities. These entities account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

The RE and NERC Compliance staffs work together to improve consistency across all RE compliance activities, increase communications and collaboration for ERO implementation, and to identify any difficulties encountered, building an effective, consistently implemented, CMEP of the ERO and identify changes necessary for future years. The results of these efforts during 2011 are summarized in the Executive Summary and are detailed in the subsequent sections of this annual report.

## Background

In 2007, there was a shift from voluntary compliance with industry-developed reliability standards to mandatory compliance with FERC-approved NERC Reliability Standards in the United States. NERC and the industry have worked intensively to transform decades of industry criteria, guides, policies, and principles into mandatory and enforceable NERC Reliability Standards in line with forces of change. A key turning point of the transformation stems back to 1996 when two major blackouts in the Western U.S. and the advent of open access transmission led NERC in 1997 to convene an independent "blue ribbon" panel (the electric reliability panel) and the U.S. Department of Energy to establish the Electric System Reliability Task Force, both groups to advise on critical institutional, technical, and policy issues necessary to maintain BPS reliability.

Both groups:

- Determined grid reliability rules must be mandatory and enforceable to ensure reliability in an increasingly competitive marketplace;
- Recommended the creation of an independent, ERO to develop and enforce reliability standards throughout North America; and
- Stated that federal legislation in the United States was necessary to accomplish this goal.

As a result, NERC implemented the blue-ribbon panel's recommendation by converting its planning and operating policies, principles and guides into planning standards. The NERC Board of Trustees (BOT) approved the reliability standards, setting the foundation for the voluntary compliance era with monitoring by NERC and the REs from 1999 through June 2007. On June 18, 2007, the first set of NERC Reliability Standards became mandatory and enforceable in the United States. Of note, in 2002, NERC operating policies and planning standards became mandatory and enforceable in the Canadian province of Ontario.

## CMEP Process

NERC and the REs continuously balance the interest in the United States to improve transparency with the confidential nature of the CMEP processes. Figure 1 is a pictorial view of the compliance process and shows how most of the processes in the CMEP fall under a window of confidentiality. NERC and the REs are continuously identifying and implementing innovative ways to share CMEP process information while honoring confidentiality requirements.

In 2010, NERC began publicly posting CMEP implementation and process information. NERC Compliance Operations has continued to review and publicly post CMEP implementation and process information in order to enhance the transparency of the CMEP and its implementation to registered entities.

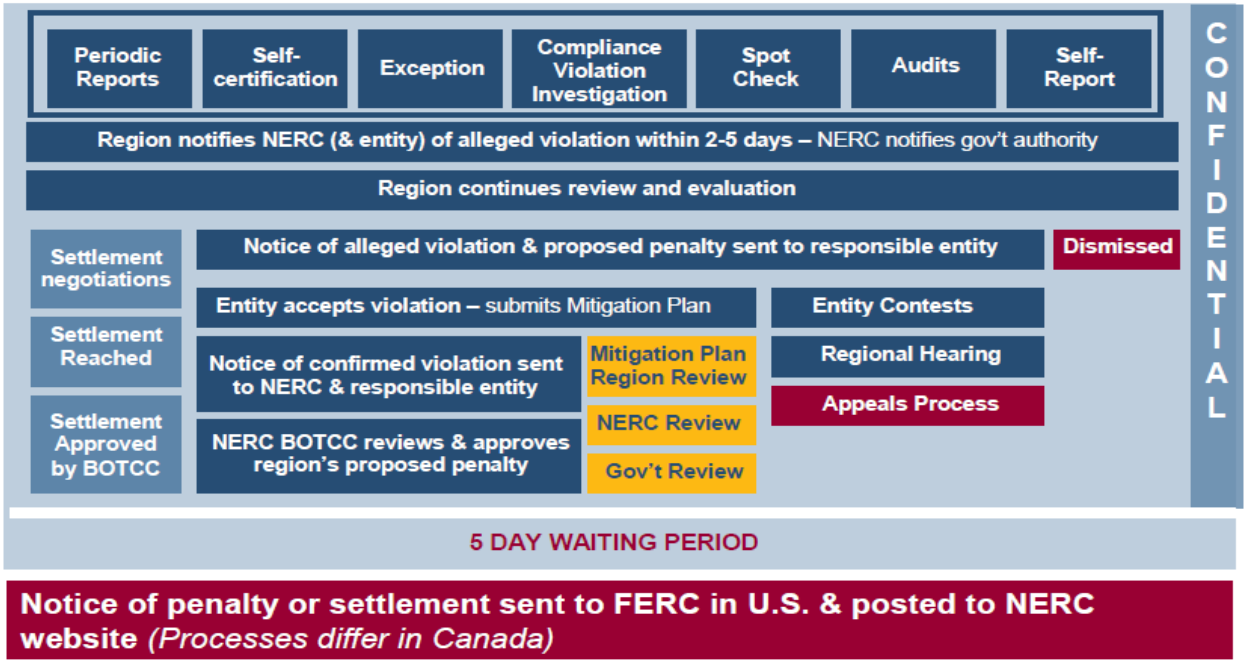



**Figure 1: The CMEP Process.**

# NERC Staff CMEP Activities

This portion of the report provides an overview of the CMEP activities for 2011 that involved NERC staff who participated in the CMEP.

## Compliance Operations Department

The Compliance Operations Department is charged with the overarching goal of ensuring the success of the REs and registered entities with respect to reliability compliance. The Compliance Operations Department is comprised of the following groups: Audit Assurance and Oversight, Compliance Interface and Outreach, and Organization Registration and Certification.

## Audit Assurance and Oversight Group

The Audit Assurance and Oversight (AAO) group participated on a number of fronts to help ensure and promote the BPS. Most notably, AAO provided oversight to the RE for six compliance audits of registered entities. A compliance application is an issue that relates to a particular application of a reliability standard that may require additional scrutiny within the ERO in addition to guidance in the form of a Compliance Application Notice (CAN) or otherwise to ensure consistent application. From these oversight activities, NERC identified 11 potential compliance applications that were shared with the NERC Reliability Standards department for future reliability standard revisions and consideration for CAN development. The AAO compliance auditors identified 13 positive observations, one lesson learned and made nine recommendations to ensure the effectiveness and consistency of Regional audit teams as they perform compliance monitoring activities within the ERO. Positive observations, recommendations and lessons learned from the 2011 RE compliance audits attended by the AAO staff were presented to the eight RE compliance auditors at the ERO Compliance Workshop, in February of 2012.[22] Oversight findings were communicated to the RE compliance auditors at the ERO Compliance Auditor Workshop, the Compliance Monitoring Program Working Group (CMPWG) and individually to the applicable RE Audit Team Lead.

Another measure promoting reliability include the AAO's support of the standard development process in the drafting of FAC-003-2 Transmission Vegetation Management.[23] For this standard, AAO provided peer review of the standard's ability to be effectively audited and to identify potential areas of concern.

AAO assisted in the review of, and proposed solutions to industry feedback regarding technical implementation concerns on MOD-029-1a's Rated System Path Methodology and its impacts on available transfer capability. This resulted in the development of a public bulletin titled "Rated System Path Methodology – Compliance Extension Request".[24]

[22] ERO Compliance Workshop information is posted on the NERC website at: http://www.nerc.com/page.php?cid=3|23|378.

[23] FAC-003-2 is BOT approved and posted on the NERC website at: http://www.nerc.com/files/FAC-003-2.pdf.

[24] This bulletin can be found on the NERC website at: http://www.nerc.com/files/DRAFT%20Bulletin%202011-00X%20MOD-029-1a%20Compliance%20Extension%2020110718%20FINAL%20for%20Posting.pdf.

In 2011, the AAO group developed several strategic programs to ensure accountability and oversight of REs' implementation of the CMEP. Of note are programs to address FERC feedback of RE compliance audits and closure of Event Analysis items being completed by the REs.

AAO participated in conference calls with FERC staff whereby FERC observers provided its feedback of the compliance audits performed by the REs. The AAO developed a FERC Feedback Tracking Process, capturing FERC issues for resolution. In 2011, NERC tracked and addressed 82 FERC observations identified in both Planning and Operations and CIP compliance audits. These observations included positive items and areas of improvement. The AAO team is capturing these lessons learned and sharing them directly with the applicable RE and will be providing training to the eight REs in the ERO staff workshops.

AAO developed a transition process and procedure between the Event Analysis (EA) department and AAO. This process assures oversight of RE's completion of compliance activities stemming from events or investigations which occurred on the BPS.

The AAO team provided NERC oversight of the Western Electricity Coordinating Council (WECC) spot check of Turlock Irrigation District (TID or Turlock) and Modesto Irrigation District (MID or Modesto). This spot check was performed in accordance with FERC Order from March 17, 2011 NP10-18-000.[25] NERC and WECC reported to FERC the results of the spot checks in accordance with the FERC order.

The Compliance and Certification Committee (CCC), a NERC BOT stakeholder committee, is tasked with assuring NERC's compliance with the rules of procedure (ROP).[26] The AAO team provided its support and expertise to the CCC in its development of RE Program Evaluation Procedure-CCCPP-010, approved by the NERC BOT. The CCCPP-010 criteria will be used in the 2012 AAO oversight of the REs performance, per ROP section 402.1.2.[27] AAO also supported the NERC staff for the CCC spot check of the NERC compliance monitoring and enforcement program and provided audit team lead training to the CCC auditors.

The AAO department produces this CMEP Annual Report, which provides a report on CMEP activities completed by NERC and the REs for the prior year. AAO developed and posted the 2010 and 2009 CMEP Annual Report in 2011.[28]

In addition, AAO participated in the first FERC performance audit of PJM in 2011.

## Risk-Based Approach

The AAO group has undertaken a number of projects to bring about a risk-based approach to compliance monitoring. Foremost in these efforts is the AML of reliability standards for 2011.[29]

[25] *See* "Order on Review of Notice of Penalty", 134 FERC ¶ 61,209 at P 53 and Ordering Paragraph B ("March 17 Order"). http://www.ferc.gov/whats-new/comm-meet/2011/031711/E-3.pdf

[26] Information regarding the CCC can be found on the NERC website at: http://www.nerc.com/page.php?cid=1|9|117|125

[27] See NERC ROP Section 402.1.2, http://www.nerc.com/fileUploads/File/Rules_of_Procedure/NERC_Rules_of_Procedure_EFFECTIVE_20120110_without_appendices.pdf

[28] The CMEP Annual Reports are located at the following link: http://www.nerc.com/page.php?cid=1|8.

[29] http://www.nerc.com/commondocs.php?cd=3

The AML has been completely redeveloped and reformatted to embody a three tiered approach. In this tiered approach, the requirements of a set of high priority reliability standards have been divided into three tiers based upon their relationship to the risk and potential impact to the reliability of the BPS. The requirements with the greatest potential risk and impact have been designated as Tier 1 and are designated as the minimum audit scope for all compliance activities occurring in 2012. Tiers 2 and 3 represent the requirements that are still significant to reliability, but have a less direct link in terms of actual performance or activities that registered entities carry out in support of reliability.

Another of these projects is AAO's support of the Compliance Enforcement Initiative (CEI). [30] Specifically, AAO has contributed to the data analysis and the auditor training program included in the CEI in order to ensure that Regional audit staff is prepared to identify and assist registered entities in their mitigation of lesser risk issues to the BPS. In addition, AAO has helped to lead the effort in the development of a registered entity risk profile assessment. This assessment will assist the ERO in its determination of appropriate audit scope based upon a number of risk related factors embodied by a registered entity, taking into account physical assets, internal controls, and compliance history among other things as part of the assessment. Audit Team Lead Training was revised to include training on the risk profile assessment.

The AAO department supported multiple projects within and outside the Compliance Operations arena to enhance and meet the corporate objective of a learning organization. AAO provided technical expertise in the development of CANs, bulletins and CARs. AAO developed two webinars to educate the stakeholders and REs compliance auditors on the 2012 AML. AAO developed and presented multiple topics at the spring and fall ERO Compliance Auditor workshops and responded to 50 compliance related questions from the stakeholders. AAO also provided Audit Team Leader Training on four times throughout 2011.

### Seminars and Communications

In 2011, NERC presented three webinars to the industry as well as to the RE staffs. The topics for the webinars included registration options (JROs, CFRs, individual organization registration) as well as certain aspects of the Certification process, including the use of a Master Matrix in connection with the appropriate function (RC, BA or TOP) questionnaire to confirm an entity has the tools, processes, training, procedures and personnel to demonstrate its ability to meet the requirements of performing these critical functions.

### Auditor Training Activities

The NERC compliance auditor training is generally based on the U.S. Government Accountability Office (GAO) Generally Accepted Government Auditing Standards[31] (GAGAS) for performance audits. Throughout 2011, NERC conducted four sessions of the Fundamentals of NERC Compliance Audits for Lead Auditors training and two sessions of CIP Standards Training (CIP Basics for Auditors). The compliance auditor training material is continuously improved based on feedback from compliance audit experiences and changes to the GAO GAGAS, CMEP and

[30] Information on the CEI can be found on the NERC website at: http://www.nerc.com/page.php?cid=3|22.

[31] See GAO Government Auditing Standards available at: http://www.gao.gov/new.items/d07731g.pdf

NERC Rules of Procedure (ROP). Additional training modules, concerning GAO Auditing Standards, random sampling techniques, critical asset identification and a review of CIP-002 sufficiency reviews, for enhancing the CIP compliance auditor skills, were developed and offered in 2011.

NERC also regularly conducts a training class for NERC and RE staff who may lead Compliance Investigations (CIs). In 2011, NERC conducted three sessions of Fundamentals of CI Training. This training material is tailored for those who may lead CIs and is continuously being reviewed and improved based on feedback from CI experiences and changes to the GAO GAGAS, CMEP, NERC ROP and internal procedures.

### Reliability Standard Audit Worksheets

The NERC RSAW are designed to add clarity and consistency to the assessment of compliance with reliability standards[32]. The RSAWs are used for multiple compliance monitoring methods. Comments on these and any of NERC's auditor resources are welcome and can be directed to the RE compliance managers.

The RSAWs are posted on the NERC public web site and provide information to the industry about expectations of the ERO compliance auditors when evaluating compliance with a reliability standard. NERC works in close coordination with the REs to ensure the information in existing RSAWs is updated with the latest regulatory authority language and guidance, and new RSAWs are developed as reliability standards are approved. It is recommended that REs and registered entities check the NERC website regularly to ensure the latest available versions of RSAWs are being used.

NERC works with REs to review these RSAWs on a continuous basis for improvement. NERC will transition the RSAWs into a database format in the near future to allow for timely updates as reliability standards are approved, modified, or retired.

### Key Reliability Standards Spot Check

NERC concluded the first KRSSC of the eight REs regarding PRC-005 and posted the public report on September 14, 2011. NERC has initiated the second KRSSC of EOP-005. The purpose of this program is to compare and contrast the procedures and processes used across the eight REs when auditing a selected set of high risk or high impact reliability standards. Through this examination, NERC will be able to identify the issues Regional audit teams experience when evaluating compliance with the selected standards in addition to identifying the areas in Regional audit evaluations where additional guidance may be needed to improve evaluation processes or to promote consistency in evaluations. It is not an objective of this program to identify a minimum acceptable audit approach, but, instead, the focus will be on increasing the consistency and quality of audit approaches across all the REs.

[32] The complete listing of RSAWs can be found at: http://www.nerc.com/page.php?cid=3|22

As an overview of the KRSSC program, NERC will request a sample of audits from all eight of the REs within a specified time period and conduct an in-depth analysis focused on selected reliability standards. Reliability standards selection will be based on:

- Severity Risk Index
- Compliance Statistics and Analysis
- Event Analysis review
- Stakeholder feedback
- NERC and Regional Entity Staff expertise

Each year, one standard will be selected for review. Performing this review will be a team of NERC auditors, who will examine non-public audit reports, completed RSAWs, and RE evidence in order to formulate any determinations. NERC will work with the Regional Entities to develop a notice to the industry to communicate lessons learned. In addition, NERC will work with the REs to improve audit procedures to respond to any consistency issues that may be identified.

### Regional Entity Program Audits - Agreed Upon Procedures (AUP) Spot Check

In 2008, NERC developed the Agreed Upon Procedures Spot Check program for auditing the REs adherence to the NERC ROP, CMEP and its ERO functional responsibilities as defined in the Regional Entity delegation agreement. This was performed in accordance with FERC Order Numbers 672 and 672-A[33]. Requirements concerning the RE audit program attributes including timelines are contained in the NERC ROP, Section 402.1.3 and Appendix 4A.

In 2010, NERC completed initial AUP audit activities of five of the eight REs (RFC, SERC, MRO, SPP RE and NPCC). NERC conducted the five audits using an independent contracting firm. The AUP approach allowed NERC to audit the REs adherence to the NERC ROP, CMEP, and the RDA requirements. Based upon experience gained and lessons learned in conducting the audits, NERC determined the audit process should be restructured to include more focus on risk and performance. With respect to the remaining three REs, NERC performed an analysis to assess the exceptions identified in the previous five audits performed. From this analysis, NERC developed a spot check audit process to verify that exceptions did not exist at the remaining three REs. NERC performed the spot check of TRE, WECC, and FRCC in the first quarter of 2011. The results of the AUP spot checks are posted at the NERC website. [34]

### Compliance Interface and Outreach Group

The Compliance Interface and Outreach group of the Compliance Opeartion Department has the primary responsibilities of developing guidance to REs and registered entities, which includes CANs and public notices.

[33] See *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).

[34] See AUP Spot Check reports at http://www.nerc.com/page.php?cid=3|26|349

## Compliance Application Notices

CANs were created by NERC, with input from the REs, to fulfill ERO obligations under FERC Order 693[35] to provide compliance guidance to CEA[36] staff and to provide transparency to industry in regard to compliance monitoring with NERC Reliability Standards. CANs encourage accountability for both CEAs and registered entities and were issued in response to requests for compliance guidance from industry stakeholders.

There are two significant and mutually reinforcing purposes of a CAN:

- To establish consistency in the application of compliance criteria across all CEAs; and
- To provide transparency to industry on how an ERO CEA will monitor compliance with a NERC Reliability Standard.

CANs are generated in a relatively short time period compared to a much lengthier formal standards development process. CANs not only assist CEAs in monitoring compliance, but the industry benefits from understanding what the issues are and how to prepare for an upcoming audit.

The CAN program was launched in 2010 and the following CANs were finalized through the end of 2011:

[35] FERC Order 693, Docket No. RM06-16-000.

[36] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

| Table 1: All Finalized Compliance Applications Notices | |
|---|---|
| **CAN Number** | **Title** |
| CAN-0005 | CIP-002 R3 Critical Cyber Asset Designation for System Operator Laptops (revised) |
| CAN-0006 | EOP-005 R7 Verification of Restoration Procedure (revised) |
| CAN-0007 | CIP-004 R4.2 Revocation of Access to Critical Cyber Assets (CCAs) (revised) |
| CAN-0008 | PRC-005 R2 Basis for First Maintenance and Testing Date (revised) |
| CAN-0009 | FAC-008 and FAC-009 Facility Ratings and Design Specifications (revised) |
| CAN-0010 | Implementation of Annual in Reliability Standard Requirements (revised) |
| CAN-0011 | PRC-005 R2 Interval Start Date for New Equipment (revised) |
| CAN-0012 | Completion of Periodic Activity Requirements During Implementation Plan (revised) |
| CAN-0013 | PRC-023 R1 and R2 Effective Dates for Switch-On-To-Fault Schemes (revised) |
| CAN-0015 | Unavailability of NERC Software Tools (revised) |
| CAN-0016 | CIP-001 R1 Sabotage Reporting Procedure (revised) |
| CAN-0017 | CIP-007 R5 Technical and Procedural System Access and Password Controls |
| CAN-0018 | FAC-008 R1.2.1 Terminal Equipment (revised) |
| CAN-0020 | TPL-002, TPL-003, TPL-004 & TOP-002 Equipment Outages |
| CAN-0022 | VAR-002 R1 and R3 Generator AVR Operation in Alternative Mode (revised) |
| CAN-0024 | CIP-002 R3 Routable Protocols and Data Diode Devices |
| CAN-0026 | TOP-006 R3 Protective Relays (revised) |
| CAN-0027 | TOP-003 R2 Coordination of Scheduled Outages |
| CAN-0028 | TOP-006 R1.2 Reporting Responsibilities (revised) |
| CAN-0029 | PRC-004 R1, R2, and R3 Protection System Misoperations |
| CAN-0030 | Attestations |
| CAN-0031 | CIP-006 R1 Acceptable Opening Dimensions |
| CAN-0039 | EOP-004 R3 Filing DOE Form OE-417 Event Reports |
| CAN-0040 | BAL-003 R2 and R5 Frequency Bias Calculation |
| CAN-0043 | PRC-005 R2 Protection System Maintenance and Testing Evidence |

In August of 2011, the NERC BOT instructed NERC to revise all existing CANs and to instruct auditors in the assessment of compliance instead of providing guidance for registered entities. The BOT also tasked NERC with revising the CAN process to allow for a high-level review mechanism, provide more opportunities for RE and industry feedback and prioritization and to outline the scope of CANs with relation to the current standard in effect.

As a result, several CANs were revised and they are indicated in the table above. The CAN Process document has also been updated and is posted on the NERC website.[37] NERC is committed to continuing and further developing the CAN program in 2012.

[37] CAN Process document can be found at: http://www.nerc.com/files/CAN%20Process%20Version%205.pdf.

## Organization Registration and Certification Group

The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved reliability standards. As described in the NERC ROP Appendix 5A *Organization Registration and Certification Manual*[38] NERC has established documented procedures to ensure a fair and impartial appeals process. From June 2007 to December 31, 2011, the ERO has processed 96 appeals, two of which were submitted in 2011 and 1 is still active at NERC. The REs have settled 65 and the BOTCC has processed 30. Four registration dockets remain open at FERC. The following figure 2 graphically illustrates the number of registered appeals that have been sought out each year and figure 3 provides the breakdown of these appeals by the applicable reliability function.

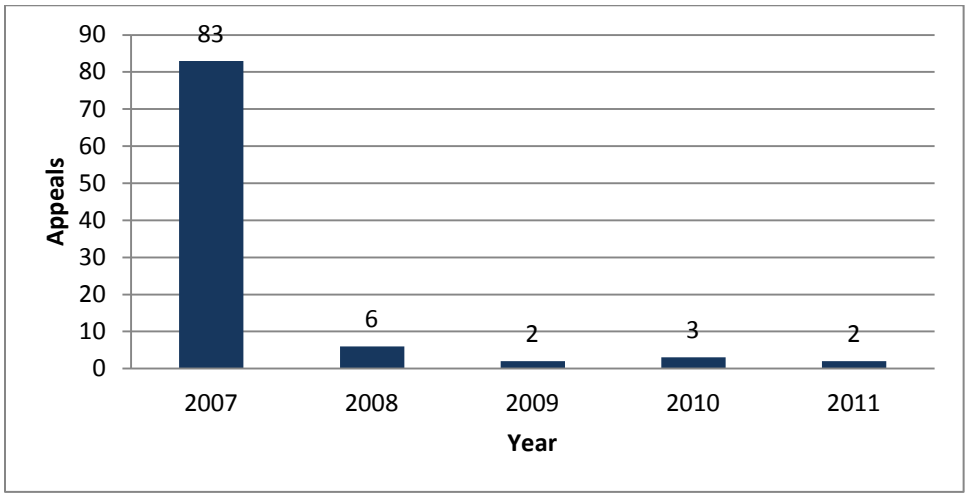



**Figure 2: Registration Appeals by Year**

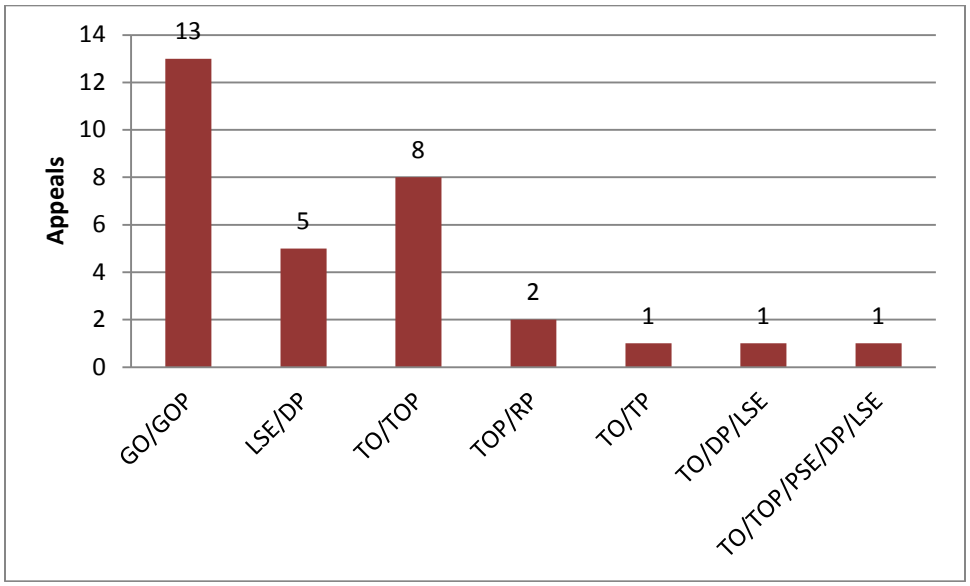



**Figure 3: Registration Appeals by Function**

[38] See *Appendix 5A: Organization Registration and Certification Manual* of the NERC ROP at: http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110412.pdf

As described in the NERC Statement of Compliance Registry Criteria, NERC will include in its Compliance Registry (the NERC Compliance Registry or NCR) each entity that meets the specified criteria for a given function. Identifying these organizations is necessary and prudent at this time for the purpose of determining resource needs, both at the NERC and Regional Entity level, and to begin the process of communication with these entities regarding their potential responsibilities and obligations. In accordance with the NERC ROP, the NCR is updated on a monthly basis. As of December 31, 2011, NERC has registered 1,914 entities on the NCR for 4,722 registered functions.[39]

The following details the entities per Region and by function. Also included is a summary of unique entities for each function.

**Registration Status as of 12/29/2011**

**Summary of Registered Entities and Functions***

| Region | Number of Registered Entities | BA | DP | GO | GOP | IA | LSE | PA | PSE | RC | RP | RSG | TO | TOP | TP | TSP | Total of Functions |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ERCOT | 218 | 1 | 46 | 108 | 88 | 1 | 58 | 1 | 42 | 1 | 1 | 0 | 30 | 16 | 28 | 1 | 422 |
| FRCC | 70 | 10 | 27 | 31 | 31 | 10 | 19 | 13 | 26 | 0 | 15 | 1 | 24 | 16 | 13 | 8 | 244 |
| MRO | 128 | 20 | 54 | 49 | 49 | 5 | 58 | 6 | 73 | 3 | 34 | 2 | 40 | 20 | 23 | 13 | 449 |
| NCEA | 3 | 1 | 0 | 0 | 0 | 2 | 0 | 1 | 0 | 2 | 1 | 0 | 0 | 1 | 0 | 1 | 9 |
| NPCC | 294 | 6 | 58 | 138 | 135 | 6 | 59 | 6 | 86 | 5 | 6 | 2 | 29 | 14 | 15 | 13 | 578 |
| RFC | 349 | 12 | 69 | 155 | 151 | 3 | 54 | 3 | 161 | 2 | 15 | 1 | 38 | 14 | 12 | 3 | 693 |
| SERC | 254 | 32 | 80 | 104 | 99 | 28 | 80 | 21 | 88 | 8 | 31 | 7 | 51 | 27 | 31 | 17 | 704 |
| SPP | 133 | 17 | 48 | 56 | 54 | 2 | 49 | 1 | 65 | 1 | 24 | 1 | 40 | 18 | 20 | 5 | 401 |
| WECC | 465 | 33 | 171 | 214 | 209 | 1 | 145 | 29 | 146 | 1 | 54 | 3 | 85 | 53 | 44 | 34 | 1,222 |
| Totals | 1,914 | 132 | 553 | 855 | 816 | 58 | 522 | 81 | 687 | 23 | 181 | 17 | 337 | 179 | 186 | 95 | 4,722 |

**Summary of Unique Entities and Functions****

| Unique Entities | BA | DP | GO | GOP | IA | LSE | PA | PSE | RC | RP | RSG | TO | TOP | TP | TSP | Unique Functions |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1,641 | 128 | 544 | 835 | 796 | 51 | 512 | 74 | 445 | 16 | 176 | 13 | 334 | 176 | 179 | 89 | 4,368 |

**Table 2: Registration Summaries**

## Multi-Regional Registered Entity (MRRE)

Initially, NERC determined to implement a program of registering entities under a Multiple Region Registered Entity (MRRE) program. Due to a number of logistical reasons, the program was temporarily suspended. Since its suspension however, a number of entities registered in multiple Regions have approached NERC to reconsider its approach. NERC, with input from the Regional Entities, is in the process of evaluating such a program. The Regional Entities are performing joint audits for many entities that are registered in multiple regions. Other processing activites are also being considered.

[39] The NCR can be found on NERC's website at: http://www.nerc.com/page.php?cid=3|25

## Organization Certification

The purpose of the Organization Certification Program is to ensure that a Reliability Coordinator (RC), Balancing Authority (BA), or Transmission Operator (TOP) has the tools, processes, training, procedures and personnel to demonstrate its ability to meet the requirements of all applicable reliability standards applicable to its function(s). Both NERC and the Regional Entities have specific roles and responsibilities regarding organization certifications pursuant to the NERC ROP Section 500 and Appendix 5A and the Organization Registration and Certification Manual.

NERC expects that the number of certifications, approximately ten per year, will remain about the same due to mergers, acquisitions, future agreement and market changes.[40]

Listed below in Table 3 are the 10 entities that were certified in 2011 along with their associated RE and the applicable functions receiving certification.

**Table 3: 2011 Certified Registered Entities**

| Registered Entity | Regional Entity | Function |
|---|---|---|
| Public Utility District No. 1 of Clark County | WECC | TOP |
| City of Springfield | SPP | BA |
| Mesquite Power, LLC | WECC | TOP |
| PJM Interconnection, LLC | RFC | BA, RC, TOP |
| Horse Hollow Generation Tie, LLC | TRE | TOP |
| New Harquahala Generating Company, LLC | WECC | TOP |
| Arlington Valley | WECC | TOP |
| City of Lansing by its Board of Water and Light | RFC | TOP |
| Hetch Hetchy Water and Power | WECC | TOP |
| Silicon Valley Power | WECC | TOP |

## GO/ TO Directive

Entities that use, own or operate elements of the BES are (i) owners, operators, and users of the BPS and (ii) candidates for registration for applicable functions. Using the registry criteria, New Harquahala (NH) was registered as a TO/TOP. NH appealed and the final ruling from FERC upheld this registration. This registry and appeal prompted formation of an Ad Hoc Group to study the registration of generation owners and operators that own and operate transmission facilities. The Ad Hoc Report:

[40] Certification final reports are can be found at: http://www.nerc.com/page.php?cid=3|25|294

- Recommended changes to requirements:
  - 32 requirements - add Generator Interconnection Facility to requirement
  - 12 requirements in FAC-003-1
  - 2 requirements – expand applicability to GO/GOP
  - 8 new requirements
- Recommended changes to compliance registry
- Recommended changes to definitions
- Recommended adding 2 new terms; and revising 5 existing terms
- Concluded "Don't register GO as TO/ or GOP as TOP solely based on Generator Interconnection Facility" if the above recommendations were followed.

To date, three entities appealed WECC's registration as TO/TOP to NERC and ultimately to FERC. These included: New Harquahala, Cedar Creek and Milford.

In each case, the NERC BOTCC and FERC upheld the registration of the entities as TOs and TOPs. Requests for rehearing and a compliance filing remains pending before the Commission.

The FERC orders made clear:

- There is an apparent gap in reliability
- All GO or GOPs or both do not have to be registered as TO or TOPs or both
- Limited set of Standards could be required and NERC was encouraged to develop a mechanism to accomplish this

In response to the report from the Ad Hoc Group, a Standard Development Team was formed (Project 2010-07) to determine which course to take to resolve FERC's concern in the apparent gap in reliability and determine the guidelines for GOs and or GOPs that own or operate a transmission facility.

Parallel to the efforts of the Project 2010-07 SDT, NERC Staff developed an interim measure intended to limit the number of GOs/GOPs that would be registered prior to revising the appropriate standards, and to provide guidance as to a limited sub-set of requirements that would apply to those that were registered as TO/TOP.

As of the end of 2011, efforts of both the Standard Drafting Team (SDT) and NERC Staff have been suspended waiting on the Board of Trustees consideration of the SDT submittal and FERC's final ruling on the appeals of Cedar Creek and Milford.

## Public Notices

NERC released in 2011 a Compliance Process Bulletin #2011-005 titled Transfer of Assets and Deployment of New Assets. This process bulletin was issued to clarify the effects of BPS asset transfers or deployment of new BPS assets as they relate to a registered entity's responsibility

for compliance with the applicable NERC Reliability Standards upon taking possession or commencing operation of these assets.

## Compliance Analysis Reports

NERC Compliance, with input from the REs, has conducted analyses of standards that have experienced a high frequency of violations since June 18, 2007. These analyses were developed in coordination with the REs, and were presented to the NERC BOTCC in the form Compliance Analysis Reports (CARs).[41] The purpose of these reports is two-fold. First, they provide information and a way to consider the most violated standards. Second, they serve as a formal mechanism to provide feedback to the standards development teams as they evaluate the requirements of a specific standard based upon compliance experience. In 2011, five CARs were released and covered the following processes:

### EOP-005 – System Restoration Plans

Since the beginning of the mandatory and enforceable standards on June 18, 2007, EOP-005 has been one of the Top 10 violated standards. As of April 1, 2011, there are 128 active or closed violations of EOP-005-1. EOP-005-2 standard was approved by FERC on March 17, 2011 with an effective date of July 1, 2013 The goal of the report was to aid REs in lessons learned for compliance with EOP-005-1.

### TOP-002 – Facility Ratings Methodology

There are three main reasons TOP-002 was chosen for a CAR:

- TOP-002 is the 4th most violated non-CIP standard, all-time;
- TOP-002 is the 5th most violated non-CIP standard in the last 12 months; and
- TOP-002 is applicable to over 63% of Registered Entities.

Self-reports and self-certifications of this standard account for 74% of the violations. This metric shows an active and aggressive compliance monitoring program and a good internal compliance program.

In this CAR, in addition to a rigorous analysis of the associated data, suggestions were offered for Industry consideration to help reduce the number of violations.

### VAR-002 - Generator Operation for Maintaining Network Voltage Schedules

As a result of the initial CAR on VAR-002-1.1b dated August 2010 and further discussion, this CAR has an addendum added to clarify the location of the point of measurement for the Transmission Operator voltage schedule.

### *NERC Organization Certifications*

This was the first analysis report on the NERC and the Regional Entity's Organization Certification Programs. This report provided a quantitative assessment of the thirty-five (35)

[41] The complete list of CARs can be found at: http://www.nerc.com/page.php?cid=3|329

organization certifications completed June 2007 through the end of 2010. NERC plans to present this information annually to give an update regarding the previous year.

### *NERC Compliance Registry and Registration Appeals*

Those on the NCR changes slightly each month as new entities are registered and others are deactivated as organizations change ownership. The lowest number of registered entities was 1,827 in May of 2008 and the highest number of registered entities was 1,940 in November of 2010.

At the time of the issuance of this report, the following was noted:

- "There are 36 registered JROs. One is in Texas RE, two are in FRCC, one is in MRO, 13 are in SERC, and 19 are in RFC. There are currently no JROs in NPCC, SPP or WECC. In the last six months, 12 new JROs have been registered with one Registered Entity entering into 11 different JROs for its DP and LSE functions in two different Regions."
- "Currently, there are 46 CFRs comprising registrations for 144 entities and representing a total of 185 functions. While many entities are only registered in a CFR for one of its functions, some entities have two or more of its functions registered with multiple CFRs. The entities involved in CFRs in each Region are: 76 in Texas RE, 33 in MRO, 19 in RFC, 10 in SERC, two in SPP, and four in WECC. There are currently no CFRs in FRCC or NPCC. In the last six months, there have been two new CFRs for a group of 12 entities that entered into CFRs for their DP and LSE functions."

## Reliability Risk Management Department

The Reliability Risk Management Department combines the technical expertise of NERC's system awareness staff, events analysis staff and event investigators to facilitate efficient processing of BPS events and to provide lessons learned to the industry to promote increased reliability of the BPS.

In the fourth quarter of 2011, the NERC Events Analysis and Investigations groups were combined with BPS Awareness into a single functional group designated as Reliability Risk Management (RRM). This new group's mission is to ensure the reliability of the BPS by ensuring situational awareness of evolving events, conducting events analysis of events and occurrences; providing lessons learned and needed reliability industry alerts to industry stakeholders and addressing any resulting reliability concerns through interaction with Regional compliance staff. In addition, the investigations group may independently conduct compliance investigations as warranted.

The focus of RRM is to:

- capture credible system awareness information for BPS events and system conditions
- conduct robust event analysis using cause analysis and risk-based methods
- facilitate the gathering and dissemination of lessons learned and relevant reliability communications to industry stakeholders in a timely manner
- ensure appropriate level of compliance oversight for BPS events

On October 25, 2010, after considerable input from industry, REs, and regulators, the ERO enterprise initiated Phase I of a Field Trial.[42] This voluntary process identified clear event categories, established associated levels of analysis and reporting and emphasized the importance of registered entities performing a systematic compliance self-assessment. In May 2011, Phase II of the Field Trial began with revised criteria for classifying events and expected responses from registered entities, Regional Entities and NERC based on information acquired during the earlier phase. Version 1 of the Electric Reliability Organization Event Analysis(EA) Process document was endorsed by the Operating and Planning Committees (PC) in January 2012; and approved by the NERC BOT on February 9, 2012. This version went into effect on February 21, 2012. While the components of the ERO Event Analysis Process – Version 1 document are not included in the NERC ROP, the program has been embraced by industry.

The ERO EA Process – Version 1 document process sets the expectation that entities will complete a preliminary event report. The higher the category of event, the more detailed analysis the registered entity is expected to perform and share with the Regional Entity and ultimately NERC. This significant amount of information, voluntarily provided by registered entities, has resulted in a significant reduction in the number of compliance investigations being initiated.

Additionally, the ERO EA Process – Version 1 document sets the expectation that registered entities should perform a critical self-assessment of standards and to develop a compliance self-assessment report proportional to the significance of the event or risk to the BPS. Since the start of the field trial through the end of 2011, there were 220 qualified events. registered entities conducted and shared their compliance self-assessments with Regional Entities in roughly half of these instances. In conjunction with these self-assessments, there were 15 self-reported violations of reliability standards.

Through the event analysis process, the Regional Entity compliance staff becomes aware of the event and engages with the registered entity to establish a time table for the compliance self-assessment by the entity. Upon receipt of the entity self-assessment, the Regional Entity prepares an evaluation of the event compared against relevant standards and shares that with NERC. In situations where formal compliance monitoring is indicated, the follow-up is done by the Regional Entity.

In 2011, the Bulk Power System Awareness (BP-SA) Group published nine NERC Alert Advisories and coordinated response activities for two NERC Alert Recommendations. Additionally, BP-SA coordinated Crisis Action Plan conference calls with the REs and governmental entities for high impact low frequency events like the April tornados in the South, the hurricane in August and the Northeast Snowstorm in October. NERC triaged over 950 BPS events and occurrences and publish 22 lessons learned,[43] operational experience reports,[44] and reminders to the industry.[45]

[42] See *Electric Reliability Organization Event Analysis Process: Field Test Draft* at: http://www.nerc.com/docs/eawg/Event_Analysis_Process_Field_test_DRAFT_102510-Clean.pdf

[43] Lessons Learned from the EA&I group are available at: http://www.nerc.com/page.php?cid=5|385

[44] Operational Experience Reports, otherwise known as System Disturbance Reports, are available at: http://www.nerc.com/page.php?cid=5|66

[45] Reminders to the Industry in the form of NERC Alerts are available at: http://www.nerc.com/page.php?cid=5|63

In addition to the contribution made to event analysis during 2011, the Reliability Risk Management (RRM) group:

- Completed five NERC-led CIs
- Participated in four Regional Entity-led CIs
- Initiated no NERC-led CIs

### Human Performance

NERC has initiated a human performance program, to not only allow a more thorough analysis of the events on the BPS, but also to create a proactive focus on reducing human error and those precursory factors that allow human error to impact system reliability. The transfer of these important reliability messages requires a variety of instruments that can advise practices and training, particularly those that can affect the reliability of the BPS. Sharing across the North American industry allows expertise and experience to strengthen the grid as a whole, making everyone more successful in meeting reliability objectives. The techniques and procedures that NERC is using to propagate this initiative include conferences, workshops, webinars, and publications with facilitated active sharing among NERC and its stakeholders. A purposefully designed NERC sponsored Human Performance Conference is being planned for 2012 to address challenges related to human performance on the reliability of the BPS.

While human error is cited for a large part of the contributing causes for events on the BPS, the RRM is partnering with industry in the EA process and has initiated a new trending analysis system to assimilate the information received in entity reports. The process will aid in developing corresponding corrective action plans to address the causes of an event or failure and prevent reoccurrence of events by creating the databases needed to apply the principles of effective risk management. After an investigation, analysis, or determination of causal factors of any event, RRM studies the event or occurrence, often leading to the identification of root causes and causal factors that could drive larger events on the BPS. These processes are applied to all levels of the ERO enterprise, including NERC, the Regional Entities, and industry participants that conduct event analysis and are involved in corrective action programs when a cause analysis is required. This process is designed to be a companion process to the *Electric Reliability Organization Event Analysis Process Manual*. It is designed to assist those responsible for labeling and trending the causal factors and latent deficiencies leading to BPS events or failures.

### Standards and Training Department

The number of standards has steadily grown since 2007. According to the 2011 AML, reviewed in Appendix A below, at the beginning of the year, the number of reliability standards reached 102. Of these 102 standards, registered entities were tasked with demonstrating compliance with 39 standards within compliance audits, 53 standards for self-certifications, one standard with spot checks, and 14 standards for periodic submittals.

#### Standards Development

Changes made to those reliability standards referred to as 693 standards, in reference to FERC Order No. 693, encompass six updates to existing standards and the implementation of seven

new standards. In terms of the CIP Standards, also referred to as 706 standards in reference to FERC Order No. 706, CIP-005-3 and CIP-006-3 underwent interpretations in 2011. Table four accounts for these standards and notes the date in which the standard became effective.

| Table 4: 2011 Reliability Standards Changes | | | | | |
|---|---|---|---|---|---|
| **Standard** | **Effective** | **Standard** | **Effective** | **Standard** | **Effective** |
| BAL-006-2 | 4/1/2011 | IRO-006-WECC-1 | 7/1/2011 | PRC-004-1a | 9/26/2011 |
| BAL-502-RFC-02 | 5/23/2011 | IRO-008-1 | 10/1/2011 | PRC-004-WECC-1 | 10/1/2011 |
| CIP-001-2a | 10/1/2011 | IRO-009-1 | 10/1/2011 | PRC-005-1a | 9/26/2011 |
| CIP-005-3a | 2/2/2011 | IRO-010-1a | 10/1/2011 | TOP-001-1a | 11/21/2011 |
| CIP-006-3c | 5/19/2011 | MOD-001-1a | 4/1/2011 | TOP-002-2b | 10/20/2011 |
| EOP-002-3 | 10/1/2011 | MOD-004-1 | 4/1/2011 | TOP-003-1 | 10/1/2011 |
| FAC-002-1 | 10/1/2011 | MOD-008-1 | 4/1/2011 | TOP-005-2a | 10/1/2011 |
| FAC-501-WECC-1 | 7/1/2011 | MOD-021-1 | 4/1/2011 | TOP-006-2 | 10/1/2011 |
| INT-003-3 | 4/1/2011 | MOD-028-1 | 4/1/2011 | TOP-007-WECC-1 | 7/1/2011 |
| IRO-002-2 | 10/1/2011 | MOD-029-1a | 4/1/2011 | TPL-002-0b | 10/24/2011 |
| IRO-004-2 | 10/1/2011 | MOD-030-2 | 4/1/2011 | VAR-001-2 | 10/1/2011 |
| IRO-005-3a | 10/1/2011 | PER-004-2 | 4/1/2011 | VAR-002-WECC-1 | 7/1/2011 |
| IRO-006-5 | 7/1/2011 | PER-005-1 | 4/1/2011 | VAR-501-WECC-1 | 7/1/2011 |
| IRO-006-EAST-1 | 7/1/2011 | PRC-002-NPCC-1 | 10/20/2011 | | |

### Critical Infrastructure Protection Standards

The year 2011 continued to be an eventful year for the Critical Infrastructure Protection CIP standards. While a single version of the CIP Standards was in effect for the entire year, there was significant activity in future versions of the standards (*i.e.* the filing of Version 4 with FERC, FERC issuance of the Version 4 approval NOPR, and the initial posting and ballot of Version 5) which required significant attention from the Registered Entities. Throughout the year, the ERO continued the efforts for ensuring better compliance with the CIP Standards. These efforts are the following:

**Transparency**. The Critical Infrastructure Department (CID) worked jointly with REs to improve the consistency of compliance program results; improve risk-based approaches for auditing and spot checking; and promote a culture of security and compliance through education, transparency and incentives. Specifically, CID participated in 14 audits during 2011, all but one being observations of RE auditors as they assessed compliance of entities with the CIP standards. CID observers offered support to the audit team, bringing a perspective of consistency to interviews with subject matter experts, offering constructive feedback about auditing technique, or sharing lessons learned from other audits that focused on CIP Standards Requirements 002-009. In addition to the assigned CIP Oversight Audits of REs, the CIP auditors were engaged with the following programs and initiatives in 2011:

- Managed the Technical Feasibility Exception (TFE) program, to include interface with the Regional TFE managers and preparation of the annual report to FERC

- Coordinated and planned CIP Auditor Workshops
- Facilitated and provided administrative support to the CIP Compliance Working Group Provided CIP subject matter expert presentations to Regional compliance workshops
- Provided CIP subject matter expertise (SME) and compliance liaison to the Cybersecurity 706 Standard Drafting Team
- Provided CIP subject matter expertise to the Situational Awareness for FERC, NERC, and the RE programs
- Provided subject matter expertise to NERC EA and Investigations
- Provided CIP subject matter expertise in response to queries from industry and the public, as submitted via NERC's web site
- Participated as a liaison for CIP compliance issues or concerns during weekly NERC and FERC status conferences

**Uniformity.** CID worked with the REs and industry to develop an objective basis for registered entities to identify critical assets for CIP-002, which was approved in 2010. Version 4 of the CIP reliability standards, which includes bright-line criteria, provides a specific list of assets for entities to consider critical, rather than having each entity develop a methodology to determine its critical assets. This significant accomplishment enables entities to more efficiently and effectively identify Critical Cyber Assets and deploy appropriate controls to protect those assets.

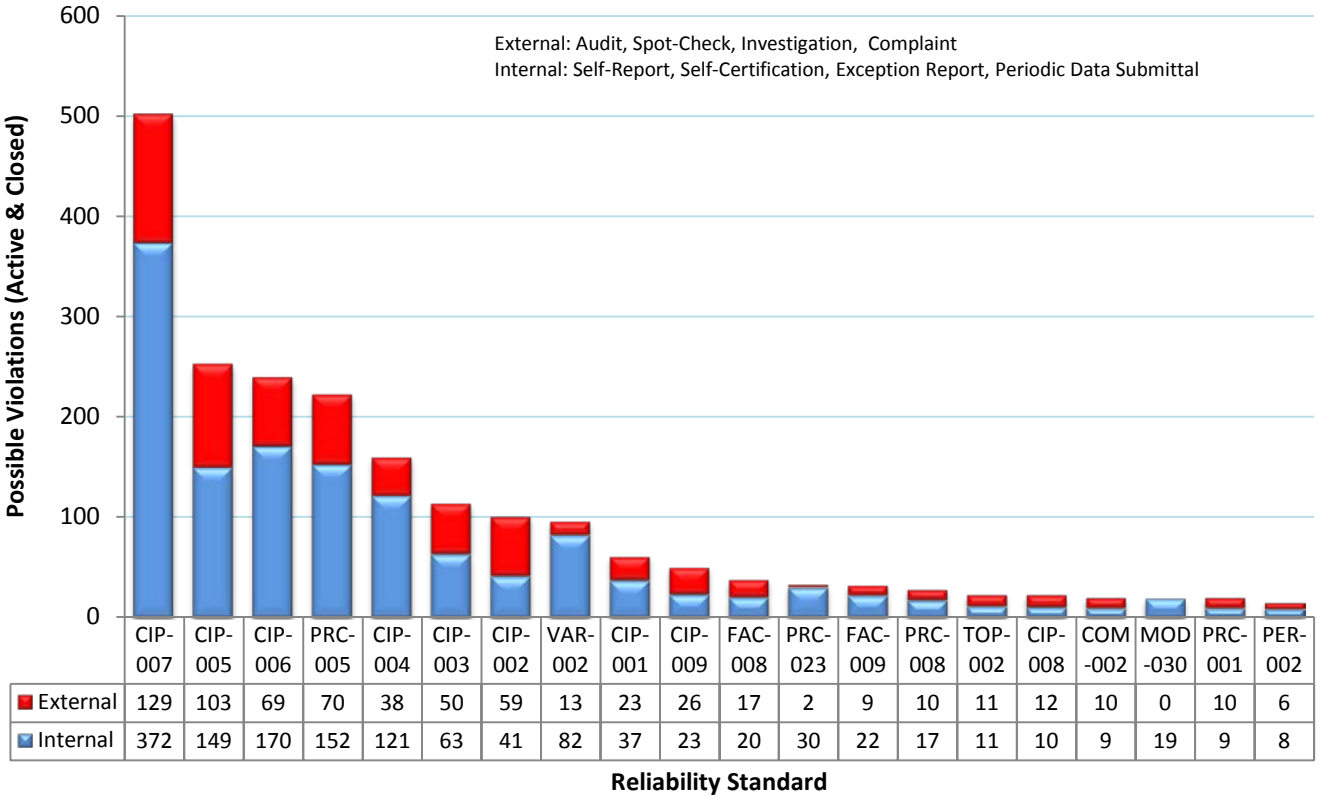
**Sufficiency.** CID continued to conduct the Sufficiency Review Program (SRP), an outreach to registered entities that examines the Risk-Based Assessment Methodology (RBAM) that is required by CIP-002-3. The SRP examines whether an entity's RBAM is sufficient to properly identify the Critical Assets that ensure the safe, reliable operation of the BPS. CID conducted ten SRP's in 2011.

**Standards Development.** The ERO continued the development of "Version 5" of the CIP Standards through the year. While the main focus of the Version 5 development was to address all the remaining FERC Order No. 706 directives, numerous other changes based on practical experiences from both registered entities and ERO audit staff (i.e. NERC and the Regional Entities) were included. In addition to the experiences provided by team members, the SDT held several informal meetings with both Regional CIP Audit Staff, and additional Registered Entity staff to better shape the standard prior to posting.

### Enforcement Department

A graph of the number of violations in 2011 relative to the NERC Reliability Standards, Figure 4, provides a look at the twenty most violated reliability standards for 2011, highlighting the discovery method as either self-identified or externally discovered. Self-identified violations are violations that registered entities recognize within their own organization by way of self-reports, self-certification, periodic data submittals, and exception reporting. Externally discovered violations are those that are discovered by the ERO staff through compliance audits,

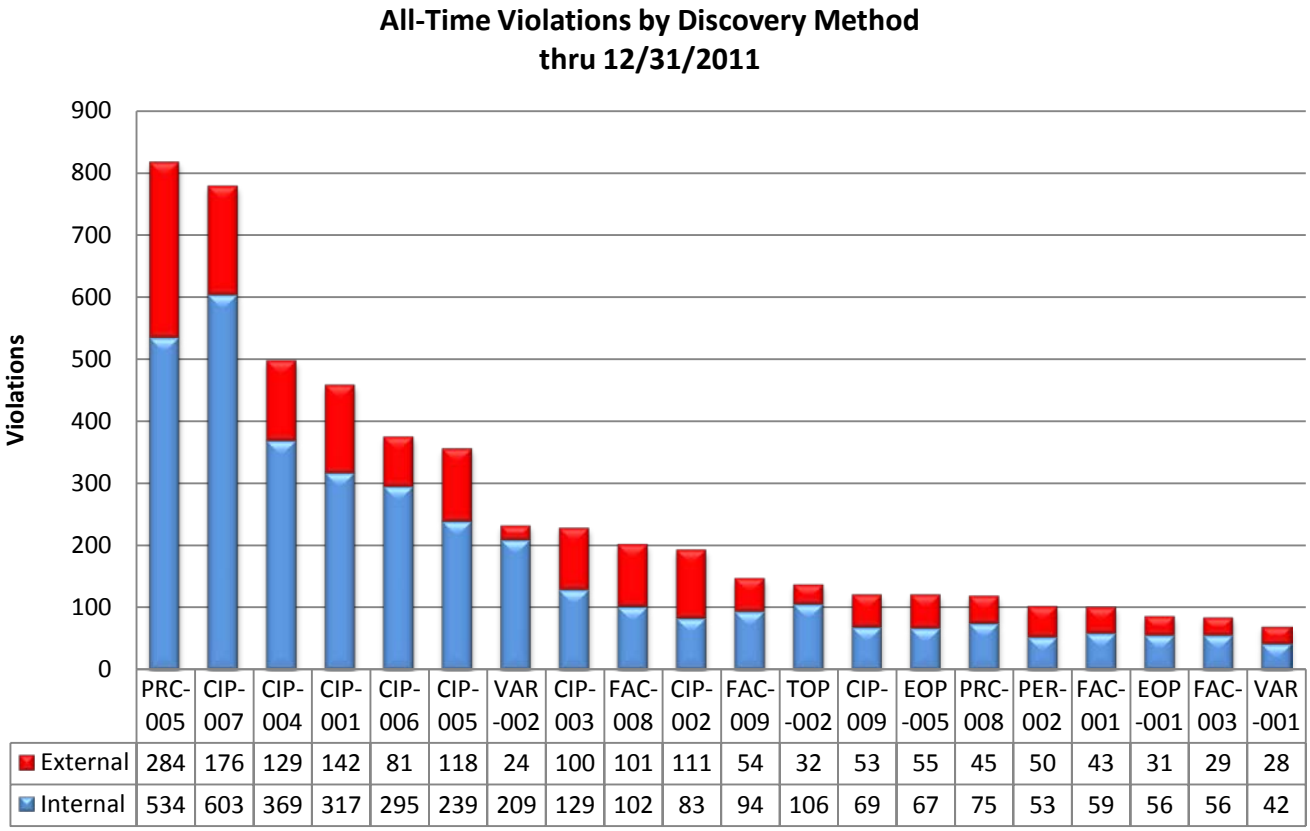
spot checks, complaints, and investigations. Eight of the top ten most violated standards in 2011 are CIP standards.




| | CIP-007 | CIP-005 | CIP-006 | PRC-005 | CIP-004 | CIP-003 | CIP-002 | VAR-002 | CIP-001 | CIP-009 | FAC-008 | PRC-023 | FAC-009 | PRC-008 | TOP-002 | CIP-008 | COM-002 | MOD-030 | PRC-001 | PER-002 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| External | 129 | 103 | 69 | 70 | 38 | 50 | 59 | 13 | 23 | 26 | 17 | 2 | 9 | 10 | 11 | 12 | 10 | 0 | 10 | 6 |
| Internal | 372 | 149 | 170 | 152 | 121 | 63 | 41 | 82 | 37 | 23 | 20 | 30 | 22 | 17 | 11 | 10 | 9 | 19 | 9 | 8 |

**Figure 4: Top 20 Violated NERC Reliability Standards for 2011**

In terms of the top twenty most violated standards for the period of June 18, 2007 through the end of December 2011, it is noteworthy that seven of the ten most violated standards are CIP standards, as shown in Figure 5.




| | PRC-005 | CIP-007 | CIP-004 | CIP-001 | CIP-006 | CIP-005 | VAR-002 | CIP-003 | FAC-008 | CIP-002 | FAC-009 | TOP-002 | CIP-009 | EOP-005 | PRC-008 | PER-002 | FAC-001 | EOP-001 | FAC-003 | VAR-001 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| External | 284 | 176 | 129 | 142 | 81 | 118 | 24 | 100 | 101 | 111 | 54 | 32 | 53 | 55 | 45 | 50 | 43 | 31 | 29 | 28 |
| Internal | 534 | 603 | 369 | 317 | 295 | 239 | 209 | 129 | 102 | 83 | 94 | 106 | 69 | 67 | 75 | 53 | 59 | 56 | 56 | 42 |

**Figure 5: Top 20 Violated NERC Reliability Standards All Time through 2011**

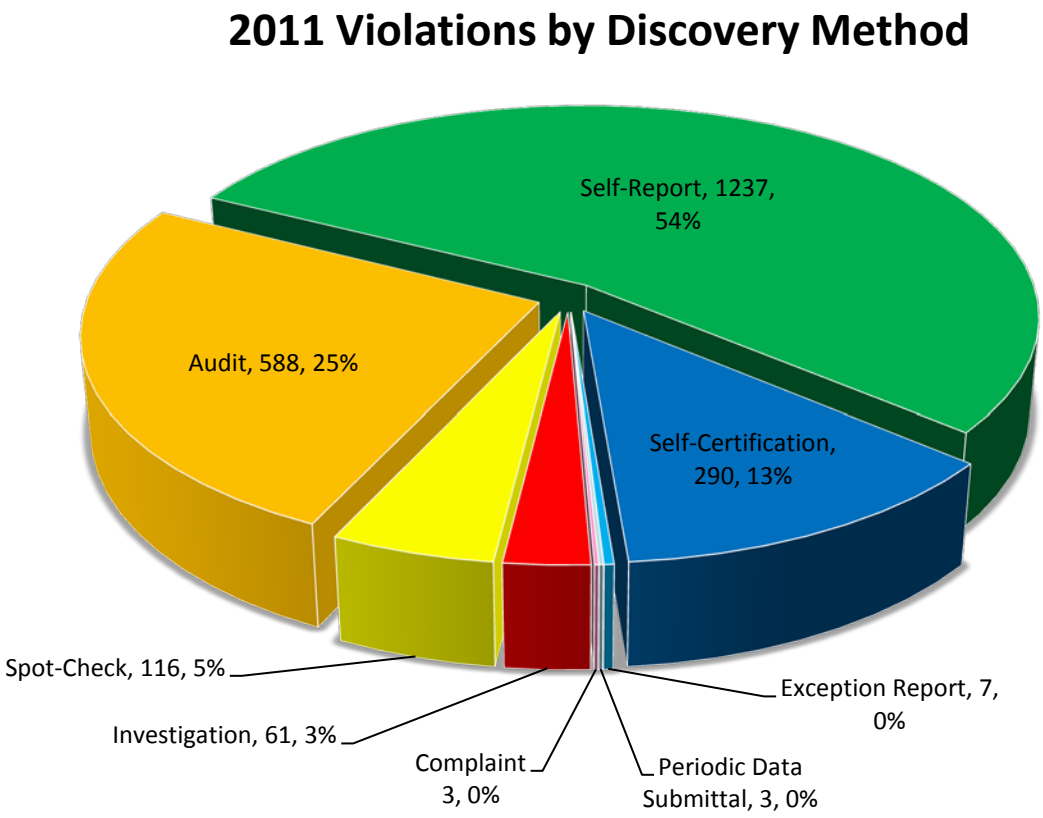



**Figure 6: Discovery Methods of the Top 20 Violations of NERC Reliability Standards in 2011**

Figure 6 provides a breakdown of the violations in 2011 by way of discovery method. The largest proportion of violations within 2011 was discovered by way of self-reports, which is very positive considering that self-reports reflect an internalized understanding of reliability standards. Self-identified discovery methods, both self-report and self-certification, account for 67% of all violations discovered in 2011. This equates to a 2% increase in self reporting from 2010. The second most frequently occurring discovery method for violations in 2011 was compliance audits at 25%. Externally identified discovery methods account for 33% of all discovered violations in 2011.

Self-identified discovery methods, both self-report and self-certification, account for 67% of all violations discovered in 2011.

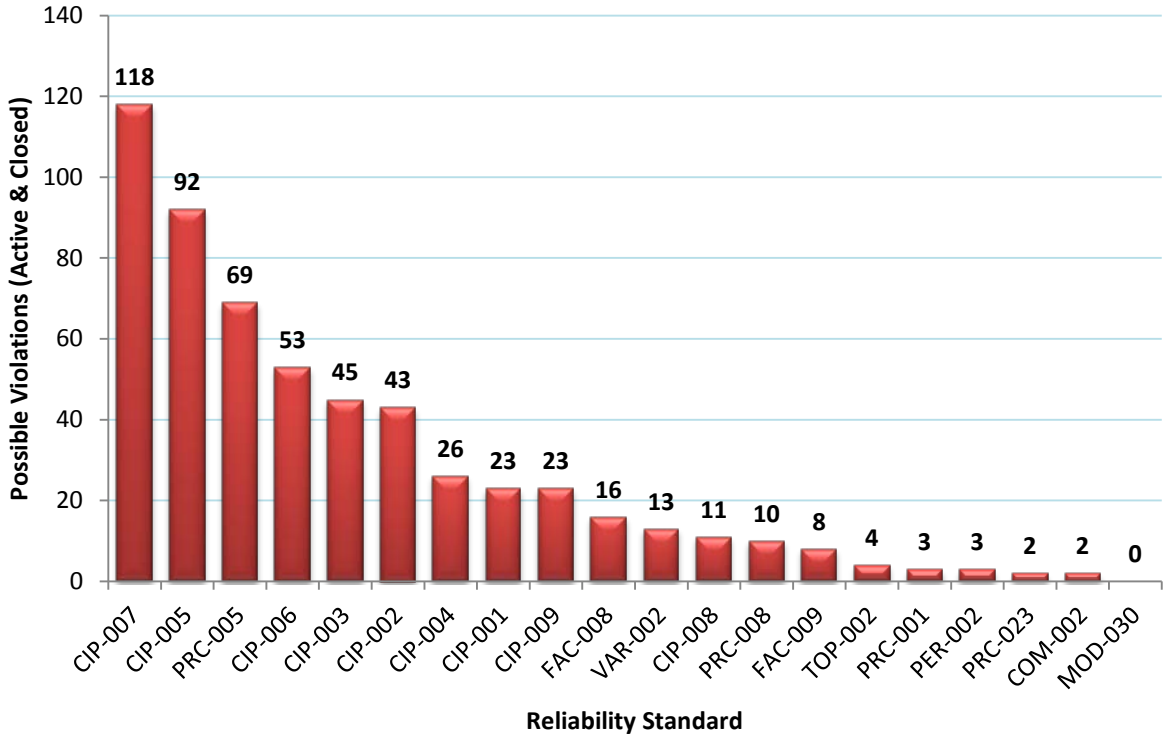



**Figure 7: Violations Discovered during an Audit by Standard in 2011**

The NERC Reliability Standards that received PVs that were discovered during an audit are graphically depicted in figure 7. As with the most violated standards of all time, CIP-002 through CIP-009 standards are heavily represented, accounting for seven within the top ten.

The following figures 8 and 9 show the breakdown of PVs by way of a registered entity's function. Figure 8 describes this relationship over the year of 2011, whereas; figure 9 describes the data from an all time perspective of 2007 through 2011. Generally speaking, these two sample data sets are extremely similar; indicating that known challenges with standards compliance continue to predictability affect entities with the same BES function. Collectively, the Transmission Operator (TOP) and Transmission Owner (TO) functions outpace all other functions for the most PVs. Generator Operator (GOP) and Generator Owner (GO) collectively follow the transmission functions and also lead the remaining functions. Although not as often as the previously mentioned functions, the Load-Serving Entity (LSE), Balancity Autority (BA), and Transmission Service Provider (TSP) functions consistently draw a significant number of PVs. The remaining nine functions are mildly represented with regards to receiving PVs.

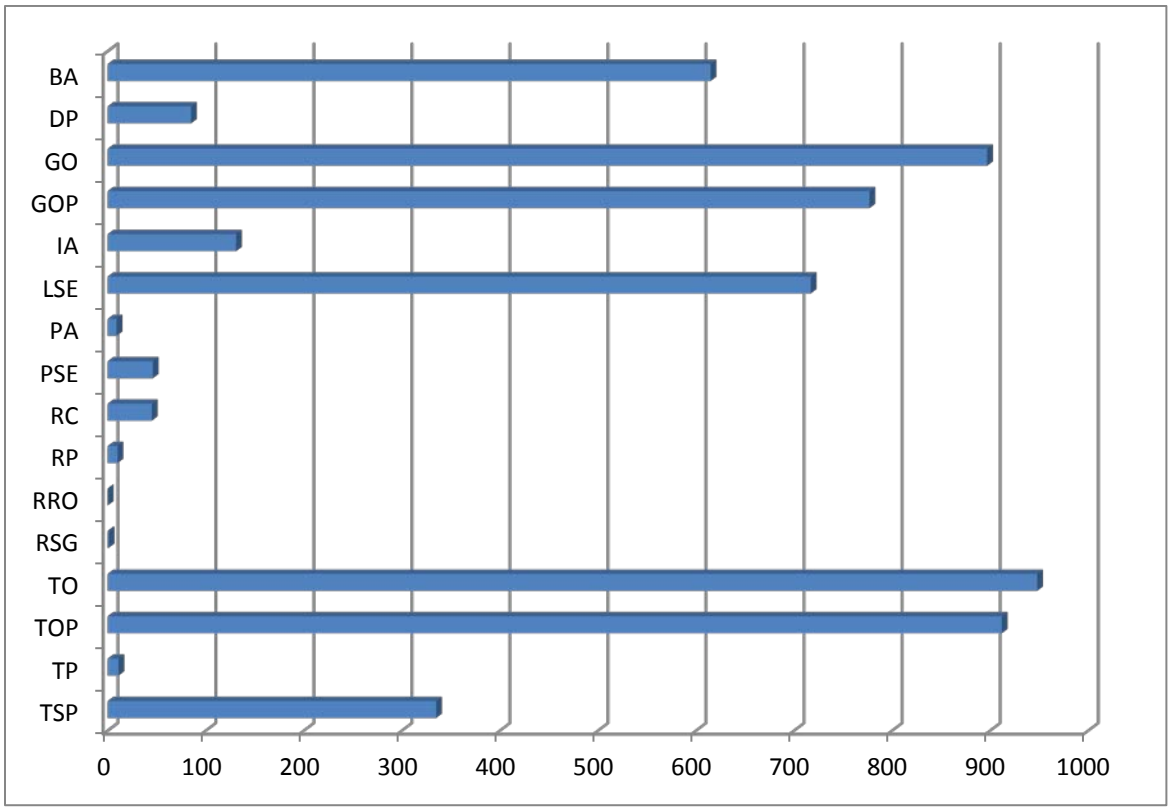



**Figure 8: Number of Possible Violations by Function for 2011**

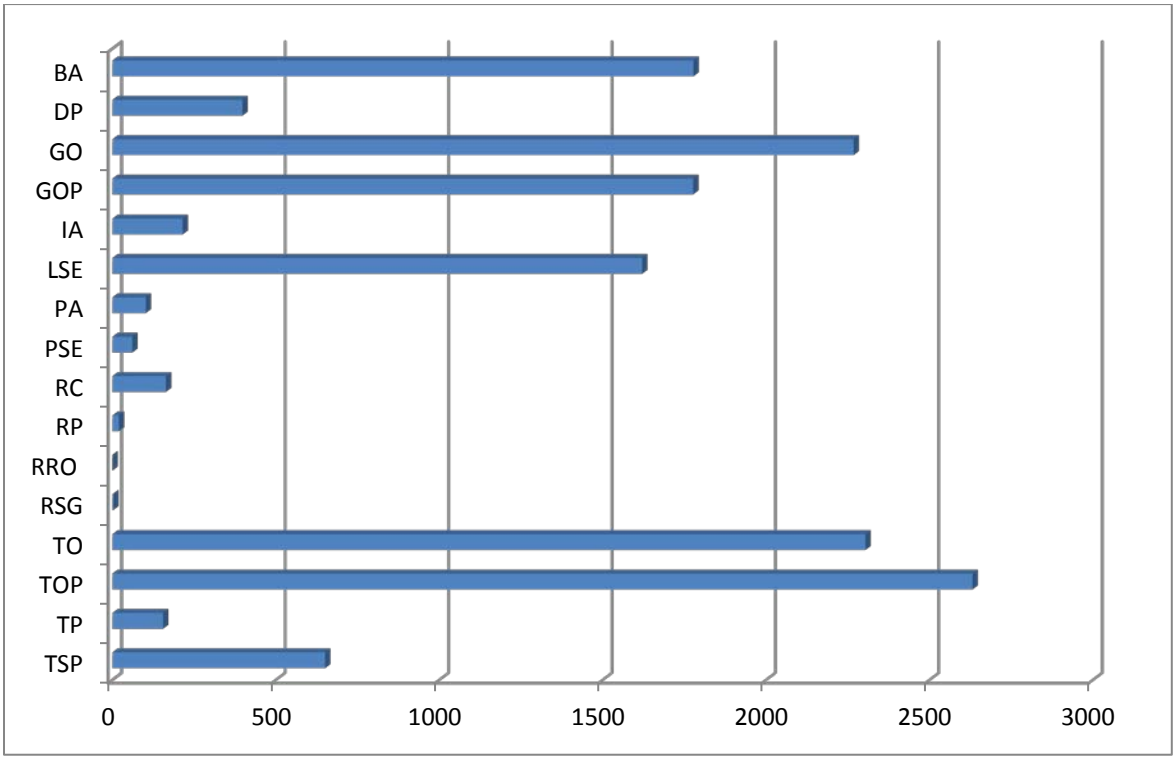



**Figure 9: Number of Possible Violations by Function for 2007 through 2011**

In an effort to measure and understand the appropriateness of using a risk-based tiered system within the 2011 AML, PV data was balanced against a standard's tier membership. The graphs on the following two pages depict this data across two separate bar charts. Figure 10 shows the number of violations that occurred with a standard that contains any of the 2011 AML Tier 1, 2, or 3 requirements. And conversely, figure 11 depicts the number of violations recorded for a standard that contained no tiered requirement.

Figure 10 shows that seven of the 45 tiered standards had 100 or more Possible Violations. The remaining tiered standards averaged nearly 12 Possible Violations per standard. As for figure 11[46] and with regards to the 34 non-tiered standards, all but four standards received less than ten PVs, with an average across these standards being three violations. Four non-tiered standards had a number of PVs well above this average: VAR-002 (Generator Operation for Maintaining Network Voltage Schedules) had 95, MOD-030 (Flowgate Methodology) had 19, VAR-501 WECC-1 (Power System Stabilizer) had 12, and BAL-005 (Automatic Generation Control) had 11 violations.

[46] As of July 2011, WECC standards VAR-STD-002a-1 and VAR-STD-2b-1were replaced with VAR-002-WECC-1 and VAR-501-WECC-1.

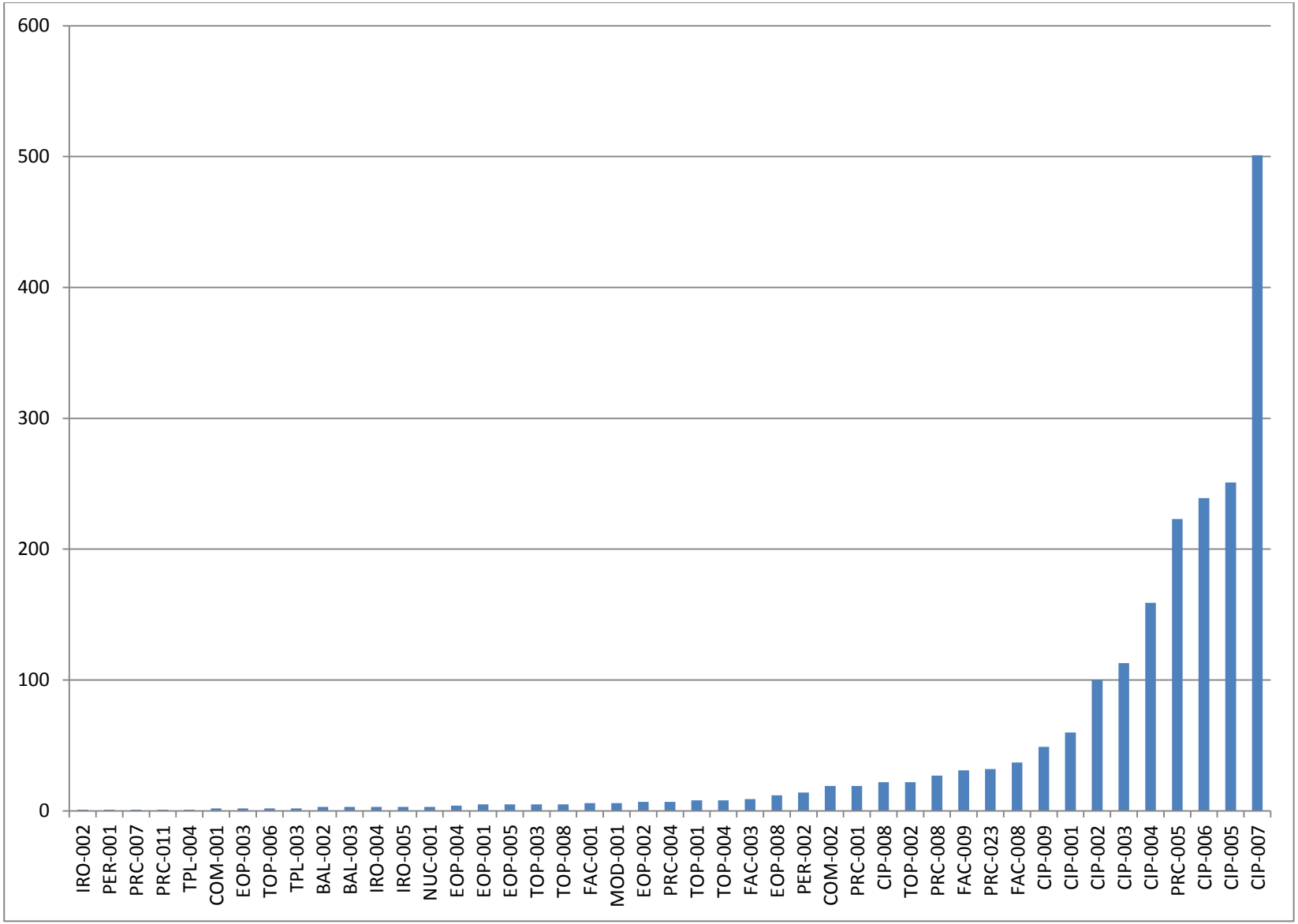



**Figure 10: Possible Violations of Tiered Standards for 2011**

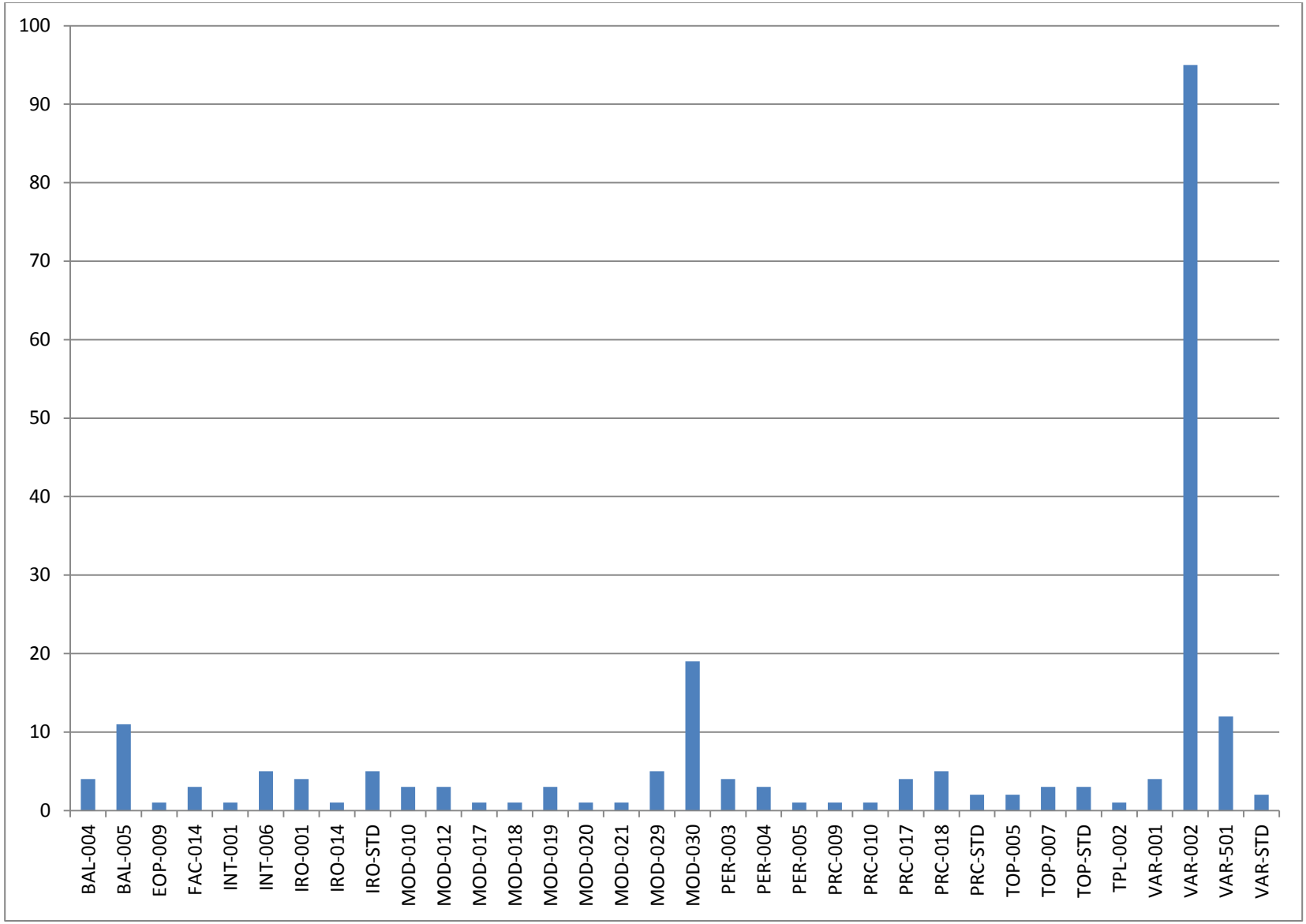



**Figure 11: Possible Violations of Non-Tiered Standards for 2011**

The below Table 5 and Table 6, identify the standards that have never been violated and the standards that have minimally been violated. This information can be used in the development of the 2013 implementation plan and future similar type risk assessments.

| Table 5: Reliability Standards That Have Never Had an Associated Possible Violation | | | |
|---|---|---|---|
| BAL-502 | IRO-008 | MOD-008 | PRC-003 |
| BAL-STD | IRO-009 | MOD-009 | PRC-006 |
| EOP-007 | IRO-010 | MOD-011 | PRC-012 |
| FAC-011 | IRO-015 | MOD-013 | PRC-013 |
| FAC-012 | IRO-016 | MOD-014 | PRC-014 |
| FAC-501 | MOD-002 | MOD-015 | PRC-020 |
| INT-007 | MOD-003 | MOD-016 | PRC-022 |
| INT-008 | MOD-004 | MOD-024 | TPL-005 |
| INT-010 | MOD-005 | MOD-025 | TPL-006 |
| IRO-006 | MOD-007 | PRC-002 | |

| Table 6: Reliability Standards with One to Five Possible Violations 2007 through 2011 | | | |
|---|---|---|---|
| FAC-002 | PRC-009 | BAL-001 | INT-001 |
| INT-005 | EOP-009 | BAL-006 | MOD-018 |
| IRO-002 | FAC-013 | INT-009 | NUC-001 |
| IRO-003 | INT-003 | MOD-006 | MOD-029 |
| MOD-020 | IRO-014 | MOD-019 | |
| MOD-021 | MOD-017 | PRC-010 | |
| MOD-028 | PRC-016 | PRC-015 | |
| PER-005 | PRC-021 | EOP-006 | |

## Enforcement Processing

Compliance Enforcement continued to improve its efficiency in processing violations of the NERC Reliability Standards in 2011. The utilization of new reporting and filing formats helped facilitiate more efficient and effective processing of violations.

The number of active violations increased in 2011. This increase resulted from growth in the average number of new violations per month from 168 in 2010 to an average of 245 violations

per month in 2011. The increase in active violations can be at least partially attributed to the implementation of NERC's CIP standards.

Compliance Enforcement implemented several new processes in 2011 that contributed to increased efficiency. The number of violations filed by NERC increased from 64 per month in 2010 to 141 per month in 2011. When factoring in dismissals, the improvement is even more vivid: in 2010, 90 violations per month were filed with FERC or dismissed; in 2011, 217 violations per month were filed with FERC or dismissed. In six of the last seven months of 2011, NERC processed more violations than it received. These successes owe to increased collaboration with REs increases in the number and expertise of Compliance Enforcement staff and improved enforcement processing tools such as FFT.

Compliance Enforcement used an Administrative Citation Process from January to August of 2011 that included the filing of 285 violations. With the Administrative Citation NOP, numerous lower-risk violations were submitted in a single streamlined NOP, reducing several levels of process and documentation. In September, Compliance Enforcement made its initial CEI filing with FERC that introduced the streamlined Spreadsheet Notice of Penalty (SNOP) and the FFT approaches to address lesser risk to reliability issues. The CEI has received significant support from the REs and the industry. The first four Spreadsheet NOP filings, containing 235 violations, were accepted by FERC with no further review. For the period of September through December 2011, 325 FFTs were filed and accepted through the Commission's March 15, 2012 Order.

For details regarding enforcements processing improvements as part of the CEI please refer to the FFT portion of the Significant 2011 Projects section of this report.

# Regional Entities CMEP Activities

Each of the eight REs have been sent a series of questions addressing seven aspects of their experience with implementing the 2011 CMEP. These seven aspects address Compliance Monitoring, Compliance Outreach, Compliance Enforcement, Program Effectiveness, Events Analysis and Compliance Review, RE Metrics, and Projections for the Future. The responses of the REs are summarized in the sections that follow.

## Compliance Monitoring

Compliance Monitoring seeks to discover a number of details surrounding the audits performed by the REs. There were 463 compliance audits planned in 2011, as identified by unique NERC Compliance Registry identification numbers. 276 of these audits were for Operations and Planning reliability standards (693 audits) while 217 of these were for CIP reliability standards (CIP audits). Figure 14 below shows the breakdown of these audit efforts by Region. NPCC, RFC, and WECC were successful in completing their planned audits. MRO had one audit with a non-FERC jurisdictional entity that was postponed for one year in order for the registered entity to develop their compliance program in accordance with reliability standards and requirements deemed enforceable by their regulatory body. SERC had one scheduled audit of a Reserve Sharing Group (RSG) that was cancelled based upon NERC approval of a reduction in audit scope. SPP had one audit that was deferred by NERC, one audit that was cancelled due to change of registration, and one audit that was cancelled due to change of registration. TRE had two audits of affiliated entities that were not completed as scheduled, because the two entities sold their assets during 2011 and were deregistered. TRE instead completed CIP and 693 spot checks of these entities. Furthermore, TRE did not complete a scheduled GO/GOP audit due to the entity becoming de-registered.

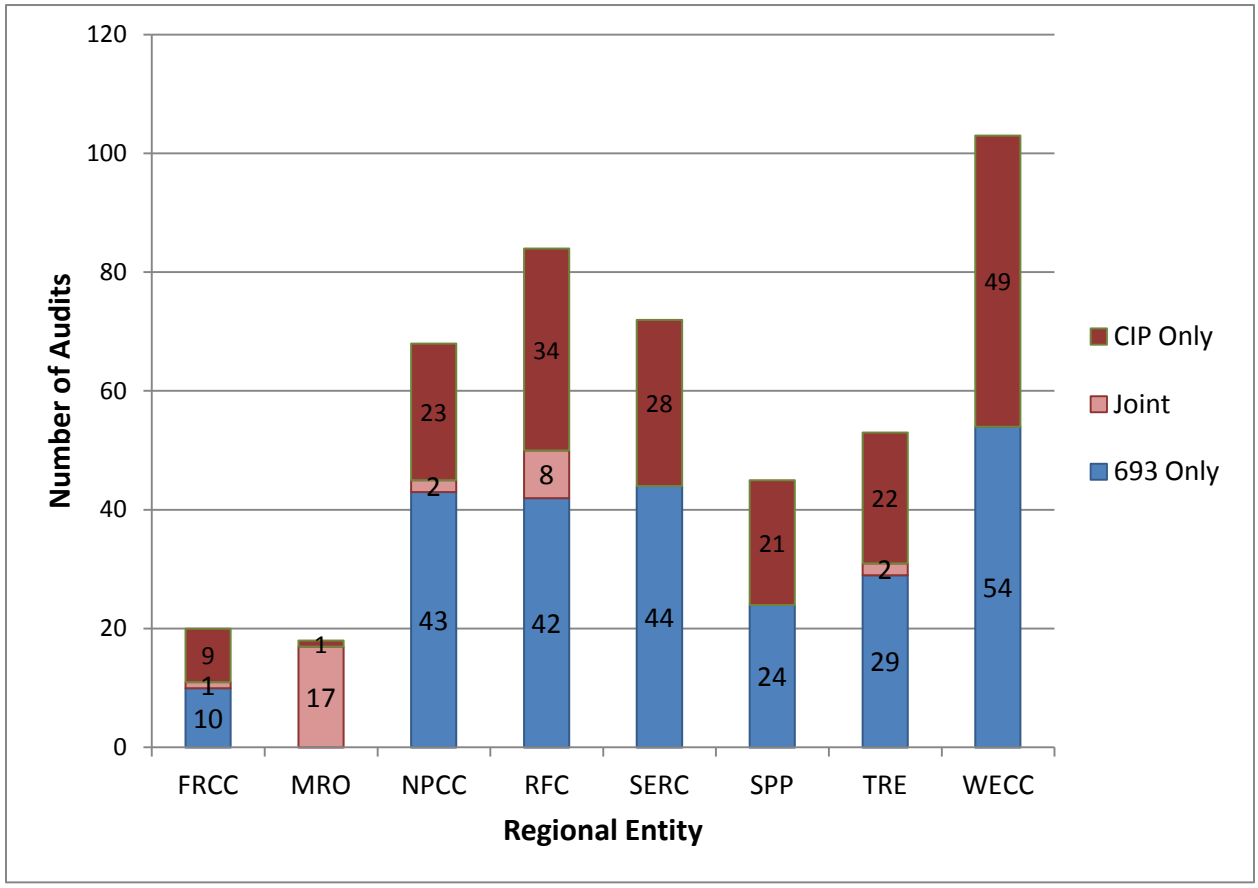



**Figure 14: Reported Regional Entity Participation in 693 and CIP Audits in 2011**

All of the REs have reported a timely completion of their three year audit cycles in 2011 with one exception. This exception relates to MRO, which, as previously described, had one audit with a non-FERC jurisdictional entity that was postponed for one year in order for the RE to develop their compliance program. This entity previously was audited in 2008 without a MOU in place. As for the six year audit cycles, all REs reported that they were on track for a timely completion in 2013.

With regards to the completion of Regional audit reports, REs have indicated that they have faced challenges in meeting the suggested 60 day timeframe requirement. Personnel resources and time are clearly the limiting factors delaying completion of the reports. That being said, most of the REs note that, when averaged, report completion is within the 60 day requirement. Of interest, one RE noted that a timeframe of 70 days is used. This allows for non-business days and still holds to the 60 day requirement.

## Compliance Outreach

Compliance Outreach looks into the REs interactions with registered entities that are taking place in order to provide information and promote transparency about the CMEP process to the registrants. To this end, all of the REs held a number of workshops during 2011 for Operations and Planning and CIP reliability standards. The number of stakeholder participants

for each RE is shown graphically in Figure 15. The total number of workshop participants amounts to 4,365. Of note, WECC accounted for roughly one-third of this total. At least a partial basis for the large number of participants for WECC is due to the fact that WECC holds monthly open WebEx calls with pre-set agendas and time for questions and answers.

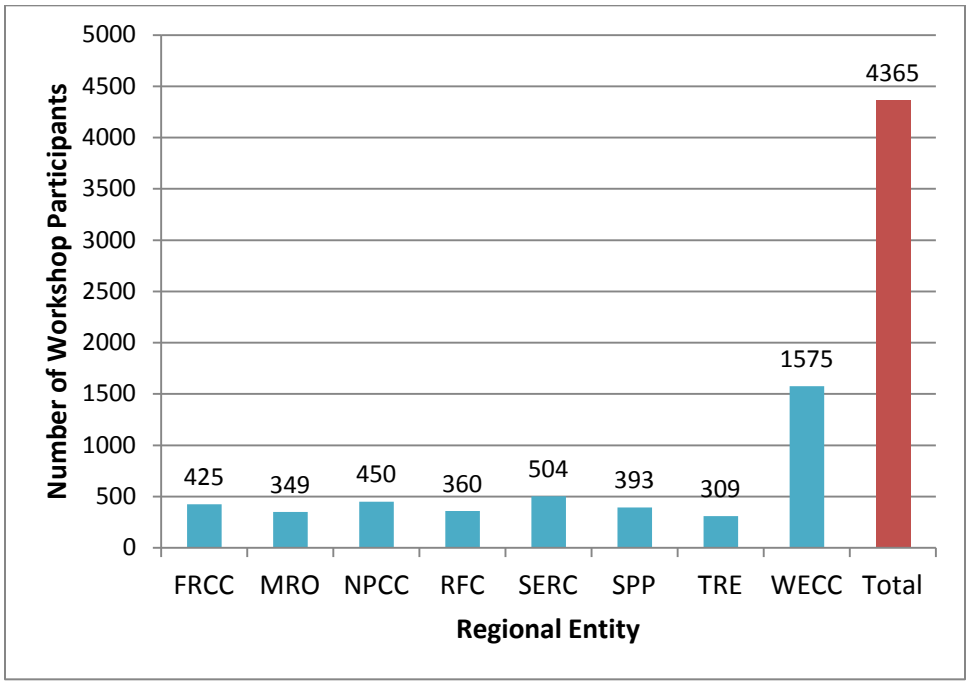



**Figure 15: 2011 Workshop Participants by Regional Entity**

Throughout the REs, feedback from the workshops has been very positive and participants are requesting that additional topics be covered. To fulfill the desire from the industry for an increased level of compliance information, as well as, to enhance CMEP transparency, many of the REs have provided workshop sessions specifically aimed at requests made by the attendees. Specifically, several REs have led presentations that teach to the application of standards and methods of demonstrating compliance. Small registered entity involvement and attendance in workshops was a priority for two REs. One Region employed mock audits as a training tool in one of the workshops that they conducted.

## Compliance Enforcement

Compliance Enforcement looks to improve enforcement processing for the benefit of registered entities, REs, and NERC. The administrative citation process brought efficiency gains to the REs, but not to the extent that was expected. Several REs pointed out that the administrative citation process utilized many time-consuming steps normally required when processing violations, such as the assessment of a violation's scope and its potential risk to BPS reliability. Some REs found value in the use of the spreadsheet for providing violation information, so they have benefited from the expanded use of the spreadsheet with the Spreadsheet NOP.

The FFT process is designed as a tool for the REs to evaluate existing and new violations to determine whether they can be processed and closed without assessment of a penalty. For

minimal risk violations for which assessment of a penalty would provide little reliability or educational value, the REs can take advantage of the FFT process to handle such violations with fewer processes and less documentation. This increased proportionality enables the REs to work more closely with their registered entities on reliability excellence instead of spending significant resources on enforcement. This is a refocusing of ERO resources, not a reduction of resources or a step back from maintaining reliability and accountability.

Many of the challenges for Compliance Enforcement programs across the REs continue to center on staffing shortages and the processing of violations, especially those dealing with CIP standards. To combat staffing shortages, many REs have indicated that a number of positions have been filled with a specific focus on improving violation processing. Also, the REs have brought on cyber security experts in dedicated compliance enforcement roles for the additional workload brought about by CIP. Compliance Enforcement continues to work with the REs on efficient processing of their violations.

Several REs noted and outlined the improvements that their compliance enforcement program underwent in 2011. Maturity of internal processes and development of competent employees directly accounted for the measurable improvements. As an example, RFC reported that outgoing violations being filed with NERC almost tripled (546 in 2011 vs. 171 in 2010), the average number of days for violation disposition decreased by 16% (228 days in 2011 vs. 270 days in 2010), and the average number of labor hours for enforcement processing of violations decreased to 59% (37 hours per violation in 2011 v. 99 hours per violation in 2010).

### Program Effectiveness

Program Effectiveness has the REs document the positive aspects encountered throughout the implementation of the 2011 CMEP as well as those areas needing improvement. Beginning with the areas needing improvement, all of the REs noted that the monitoring and enforcement of CIP standards continue to be a significant technical and logistical challenge. Additionally, the processing and management of CIP TFEs has only added to this challenge of processing CIP enforcement actions. Maintaining and increasing the staffing of qualified individuals throughout all areas within the CMEP has been difficult, not only at the Regional level but within the registered entities themselves. For example, TRE has noted that some smaller entities retain outside consultants to act as the primary compliance contact, which tends to adversely affect the entities' role in compliance monitoring or enforcement activities.

The positive aspects of the 2011 CMEP are many. As with last year, nearly all REs reported that there has been considerable growth in the number of self-identified violations, especially through self-reports and self-certifications. This increase in self-identified violations has been especially noted for those entities with comprehensive internal compliance programs that proactively assess compliance. Several REs have reported that improved data transmission processes between the audit team and registered entity have resulted in a significant reduction to the man-hours required to complete an audit. The use of secure web portals has dramatically lowered the time CIP auditor are required to be on-site and simple tools such as color coding documents or generally organizing evidence for audit review have gone a long way in making the most of audit time. Concurrently, REs have had their auditors completing due

diligence efforts more thoroughly during the pre-audit phases, likewise resulting in lowering audit time man-hours. More and more compliance programs are being projected within the policies and procedures that the registered entities are using on a daily basis, leading to, as MRO phrases it, operationalized compliance. A couple of the REs also noted that they have taken steps to more closely align their compliance monitoring and enforcement processes and documentation with NERC. SERC staff achieved a significant milestone by being the first RE to synch its compliance tracking database with NERC's database, eliminating the burdensome workbooks previously used to track status of compliance violations. The use and sharing of auditor tools, such as an evidence sampling methodology and evidence tracking sheets, has continued to help enhance consistency and efficiency across the REs. The initiation of the EA field trial has proven to be a valuable tool in terms of discovering and implementing actions for the enhancement of BPS reliability.

One of the particularly noteworthy aspects of the 2011 CMEP was the implementation of the new EA process, especially in light of the Southwest Winter Event. Being the first RE to have a Category 4 event at the time that the EA process was in evolution was quite time consuming for TRE and its registered entities. The coordination between NERC, FERC, and the Public Utility Commission of Texas was sometimes difficult to manage, causing extra burdens upon TRE and the registered entities. Most of the issues were resolved and much was learned during the analysis of the system event. Having this process completed, provides transparency and consistency for future event analysis.

### Events Analysis and Compliance Review

To support a strong culture of compliance, registered entities are expected to perform a compliance analysis and to develop a compliance self-assessment report proportional to the significance of the event or risk to the BPS for categorized events in which there could be a gap between actual system or human performance and the requirements of NERC or Regional reliability standards. Registered entities are encouraged to submit a compliance self-assessment report to the Regional Entity compliance liaison proportional to the significance of the event or risk to the BPS for categorized events. This report should encompass a sufficiency review, proportional to the event's significance, of applicable standards associated with the event.

Registered entities that make a good faith effort to self-identify and self-disclose possible violations stemming from their EA will be afforded consideration in any enforcement action in accordance with NERC's Sanction Guidelines. If further analysis by the RE or NERC reveals other PVs, the registered entity's participation and cooperation will be noted and considered.

For this reason, it is recommended that registered entities establish a liaison between their internal event analysis and compliance functions. This will provide a clearer understanding and a more efficient transfer of information from both an operational and a compliance standpoint, and it will facilitate a thorough standards review by the registered entity.

Figure 16 illustrates the number of events that have been analyzed per RE using this self assessment process.

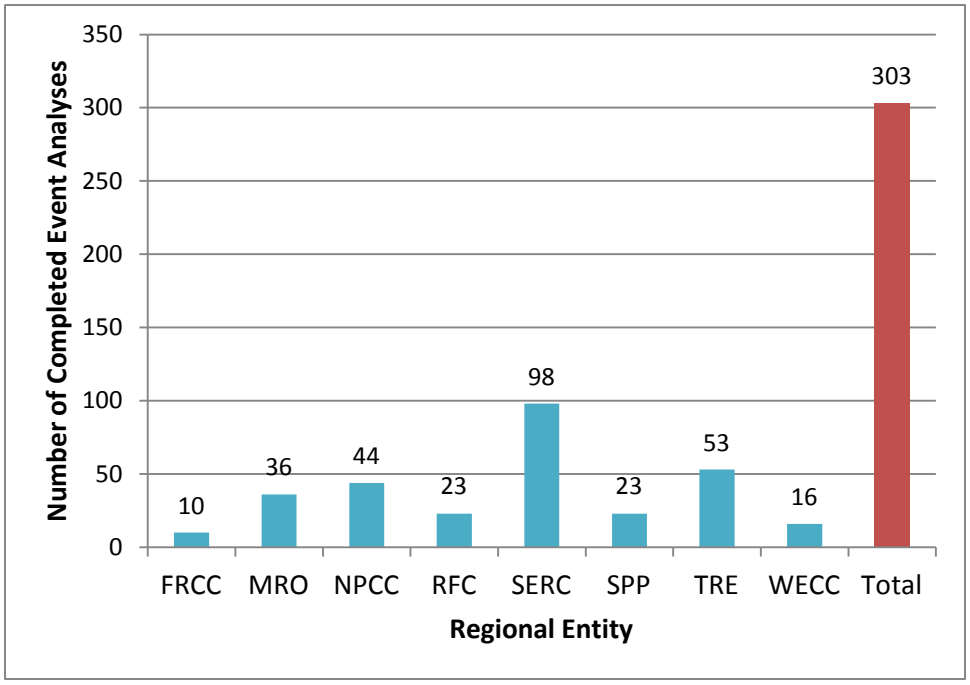



**Figure 16: 2011 Completed Event Analyses by Regional Entity**

## Regional Entity Metrics

The RE Metrics portion of the questionnaire asked the REs to describe, submit, and draw conclusions from any metrics that are being used to measure the their CMEP performance. Each RE reported that the use of metrics has been very valuable. Tracking of audits, spot checks, Notice of Violations, mitigation plans, budgeting constrains, and resource planning are common processes being monitored. Additionally, it was noted that the metrics being used are the first steps towards a series of possible metrics that could be used to track performance of stakeholders, as well as, provide a means to measure performance relative to other REs.

Adoption of specific CMEP performance metrics and goals is proving to be useful in helping focus RE staff on specific performance targets and informing management of potential resource constraints, as the metrics reveal how efficiently the REs are processing audit reports, and subsequently notifying NERC and the registered entity of compliance audit findings. For example, metrics are being used to measure the process time undertaken when enforcement is notified of a PV, until the time that enforcement notifies the registered entity of the alleged violation. Metrics such as these are helping the REs focus on key objectives in the compliance monitoring and enforcement areas and sub-sequentially helping add focus to these areas.

Moving forward, the ERO Compliance and Enforcement Management Group (ECEMG) has taken on the project of providing a means of metric consistency between the Regional Entities.

## Projections for the Future

Projections for the Future asks the REs about the improvements they would like to see instituted for progressing the CMEP in future years. The most active responses centered on the NERC AML, CEI, and risk-based auditing program.

Most REs found that the newly instituted tiered approach to auditing was beneficial, in that, the process undoubtedly identifies those standards and requirements that have a direct impact on the reliability of the BPS. That being said, each RE was able to specifically identify areas where the tiered system could be improved. Most often mentioned was including, in the same tier, all sub-requirements of any single requirement. This would lead to a more straightforward grouping and a less confusing audit approach, especially when CIP standards are being audited. Several REs commented that a review of the tiered approach as a whole should be conducted by NERC with the goal of performing a trend analysis. This could reveal if any patterns exist that might warrant a tier 2 or tier 3 requirements becoming a tier 1 requirement. Mentioned several times from RE to RE was the idea of removing the monitoring of PSE-only entities via audit or spot check as these are limited critical standards, and the value of the active monitoring may not justify its the cost. An alternate approach to PSE-only monitoring such as self-certification or targeted spot check may be sufficient to ensure compliance. On a more negative note, one RE recommended that in 2013, the AML should be developed without the tiered approached due to registered entities being confused by its implementation because of the non-uniform process being employed across the REs. Instead, NERC should identify those global risks to the BPS which are important to be monitored for 2013 based upon its perspective; using the existing reliability statics or criteria or both developed between NERC and the REs. Using this type of process, the list could more directly employ the risk-based audit approach. All standards are always subject to inclusion into a scope of an audit based upon further focused assessment of the entity by the RE. REs also requested that the AML be reviewed to avoid changes which have caused retractions and re-notifications to entities that have already been notified of audits or spot checks; thereby avoiding logistical challenges that arise when changes in audit scope occur.

The REs are supportive of the CEI and believe that being able to utilize the appropriate discretion relation to reliability risk is a step in the right direction. To further develop the process, RE workshops for the industry as a whole need to focus more on reliability risk and less on compliance risk. Moreover, registered entities need to be educated on the context of risk that needs to be addressed; especially in the enforcement process. To increase all registered entities' understanding, it would be useful if NERC were to provide training of risk assessment as used in the determination of FFT treatment or the evaluation of appropriate Penalties in NOP. As an incentive, NERC could provide a policy that an entity's participation in the EA process and the use industry compliance-self-assessment and standards-review be viewed as strong indicator of that entity's compliance and reliability culture, and therefore, that entity be rewarded by a credit based on a specific formula should a compliance violation be discovered. With regards to CEI logistics, the REs are seeking improvements in the transfer, storage, and reporting of data, as well as, a means to provide quick and ready access to comparative statistics such as violations, mitigation plans, dismissals, and disposition between themselves.

Most REs have developed a risk-based methodology to be used for conducting an assessment of each registered entity scheduled to be audited. The intent of these assessments is to identify unique entity risks which may have an impact to the BES, and as a result, select additional standards which will be recommended for implementation of the monitoring process. This approach best focuses audit team resources and, in some cases, can reduce the monitoring requirements of an entity. In their risk-based approach, Reliability*First* in 2012 will increase the

scope of any audit or decide to do a spot check if it believes that additional risks are present in the entities performance during the audit. Auditors are being made aware of the guidance coming out of NERC and will be given additional training on risk and performance based auditing as it evolves. At FRCC, they will be utilizing a draft registered entity risk-based assessment template for identifying all pertinent operating data related to a registered entity, including violation history data, to assist the compliance staff in determining the risk to the BES a particular registered entity may have. They will then be working with NERC to develop the registered entity risk-based assessment template. NPCC reports that they will evaluate each entity and the potential risk-based on entity's registered functions, risk to the BES, audit history, self reports, and spot check history of the entity. To approach the challenges of a risk-based program, MRO has sought out auditors and personnel who are credentialed, trained, and experienced. Furthermore, they recommend that NERC administer a program which develops similarly skilled personnel throughout all REs.

# Significant 2011 Projects

## Defining the Bulk Electric System

On November 18, 2010, FERC issued an Order (Order No. 743) directing NERC to revise the definition of the BES using the reliability standards development process and address the Commission's technical concerns as identified in that Order. NERC was also directed to develop and submit an implementation plan or plans for the revised BES Definition. FERC established a January 25, 2012 deadline for filing the revised BES Definition, the implementation plan, and the proposed BES Exception Procedure with the Commission. A revised BES definition and implementation plan was developed and successfully balloted through the reliability standards development process. Modifications to NERC's ROP to address the BES Exception Procedure were undertaken as well. Those modifications, along with the revised BES definition and implementation plan, were adopted by the BOT on January 18, 2012. The proposed revisions remain pending before the commission.

The proposed revised BES Definition eliminates the phrase "as defined by the Regional Reliability Organization" contained in the current definition, thereby eliminating the explicit basis for RE discretion that was one of the Commission's primary concerns in Order Nos. 743 and 743-A. It also provides a default threshold of Transmission Elements operated, and Real Power and Reactive Power resources connected at, 100 kV or higher. That "bright line" is augmented by a list of five categories of facilities that are included in the BES and a list of four categories of facilities that are excluded from the BES. The listed Inclusions and Exclusions address and provide clarity both to types of facilities that were the subject of FERC's technical concerns in Order No. 743 and to types of facilities that have been problematic previously when determining whether or not they are included in the BES.

There are three sets of proposed modifications to the NERC ROP that were made in support of this effort – modification of Section 509, Section 1703, and Appendix 5C. Section 509 states that an Element is considered to be (or not to be) part of the BES by applying the BES Definition, and that Appendix 5C sets forth the procedures by which an entity may request a determination that an Element that falls within the BES Definition should be exempted from being considered part of the BES, as well as how an entity may request that an Element that falls outside the BES definition should be considered a part of the BES. Appendix 5C sets forth the detailed procedural steps for submission of an exception request by an entity, consideration of the Exception Request by the applicable RE and NERC, and the decision by NERC to approve or disapprove the exception request. Section 1703 sets forth the steps by which an entity may ask the BOTCC to review the NERC decision to approve or disapprove an exception request.

In support of these changes, a form for the submission of Detailed Information to Support an exception request was developed. This form provides separate sets of questions applicable to Transmission Elements, and to generation resources, for which an exception is being requested. This information is used by the RE and NERC in evaluating whether the elements that are the subject of an exception request are necessary for reliably operating the interconnected transmission network. The entity requesting the exception remains responsible to present sufficient information and argument to justify it.

It is proposed that the revised BES Definition be effective on the first day of the second calendar quarter after receiving applicable regulatory approval, or, in those jurisdictions where no regulatory approval is required, the revised BES Definition should go into effect on the first day of the second calendar quarter after its adoption by the BOT. However, recognizing that there will be changes regarding what facilities fall within the scope of NERC standards based on this new definition, it is proposed that that compliance obligations for all elements newly identified to be included in the BES based on the revised BES Definition should begin 24 months after the applicable effective date of the revised BES Definition.

This work has only recently been filed with regulators, and at the time of the writing of this document, it is unclear when these changes will go into effect. As such, it is unlikely that there will be any impact to Compliance and Enforcement in 2012, but it is important to note that there is a potential for changes in the future, which may necessitate additional staff or other resources.

## Find, Fix, and Track

### FFT Filing

NERC and the REs have continued to seek ways to improve its processes and the quality of reliability standards. NERC, the REs, FERC, and the industry have discussed significant ways to retool efficiency efforts through multiple technical conferences. A key outcome was the recognition that compliance matters should be treated differently based on the level of risk posed to the reliability of the BPS.

NERC's new CEI is designed to handle issues more efficiently, focus on issues posing a higher risk to reliability, streamline administrative paperwork, and continue to encourage self-reporting and mitigation.

NERC is not looking to reduce the number of compliance items identified with this new initiative, but is rather looking to treat matters differently based upon the risk associated with them. By identifying, mitigating and quickly resolving issues that pose a minimal risk, more resources can be focused on violations that pose a more serious risk to reliability.

The CEI is being launched in accordance with NERC's Rules of Procedure. The new initiative is not about whether issues will be addressed. Rather, it is about how they are addressed.

Following NERC's filing[47] of the CEI on September 30, 2011 and FERC's Order[48] accepting the process on March 15, 2012, there are three enforcement tracks: Dismissal; FFT; and NOP. Dismissals occur where there are no violations, when the entity is not registered for and/or

[47] *See* North American Electric Reliability Corporation, "Petition Requesting Approval of New Enforcement Mechanisms and Submittal of Initial Informational Filing Regarding NERC's Efforts to Refocus Implementation of its Compliance Monitoring and Enforcement Program": http://www.nerc.com/files/FinalFiled_CEI_Document_20110930.pdf

[48] *See* Order Accepting with Conditions the Electric Reliability Organization's Petition Requesting Approval of New Enforcement Mechanisms and Requiring Compliance Filing, 138 FERC ¶ 61,193 (2012) at: http://www.nerc.com/files/OrderConditionallyAcceptingNewEnfocementMechFiling_031512.pdf

subject to a particular requirement, or where there are duplicate entries of issues. No changes are being made with respect to dismissals.

The FFT is the new portion of the compliance initiative. This process will apply when a PV poses a minimal risk to BPS reliability. All matters identified via FFT or NOP must be fixed; the registered entity must provide a statement of completion certified by an officer of the company and completion of mitigation activities is subject to verification by the RE as part of an audit, spot check or random sampling. The issue must be fixed prior to inclusion in a report to FERC. A PV processed through FFT becomes a remediated issue once included in an FFT informational filing and such filing concludes processing of that matter by REs and NERC. No penalties or sanctions will be applied to FFT issues. These remediated issues will be included as part of a registered entity's compliance history and will be taken into account in future actions as appropriate. Mitigation activities must be described in the FFT spreadsheet; however, a formal mitigation plan will not be required.

For those matters that pose a more serious risk to reliability of the BPS, NOPs will be filed. They may be filed either in a spreadsheet format or a full NOP format.

REs will review current cases and determine which disposition approach will be used based on the issue. Training of compliance and enforcement staff will take place as part of the implementation of the FFT process.

Approximately 60 percent of violations are a result of four compliance monitoring methods (self-report, self-certification, data-submittal and exception-reporting) that provide self-identified possible violation reporting by a registered entity. NERC encourages registered entities to include a full factual description of the issue, detailed information regarding mitigation activities, identification of the potential and actual risk posed as well as mitigating factors in effect while a PV is awaiting a determination of the appropriate processing track. This process will help illustrate that the registered entity understands the full scope of the violation and has taken actions to correct it and prevent recurrence.

NERC will continue to compile trend data and keep historical records on registered entities, which will allow NERC to target areas for increased education as needed. Registered entities are expected to provide information that is sufficient, complete and validated to support the issues identified for FFT or NOP treatment.

The CEI, featuring the FFT approach to minimal risk remediated issues, is a paradigm shift in how issues are processed, not whether they are addressed. In all cases, they must be found, fixed and tracked. The CEI reflects a risk-based approach that acknowledges all PVs are not equal and should not be treated as such. By focusing resources on violations that have a serious risk to the reliability of the BPS, NERC is able to better fulfill its mission as the ERO.

### FFT Implementation

During the initial phase of FFT implementation, auditors are able to recommend FFT treatment of certain audit findings, but the decision to afford FFT treatment to a specific issue resides with the RE enforcement staff. The next phase of the CEI, currently targeted for 2013, will vest the

decision of processing a violation through the FFT process with the CEA compliance staff as well as enforcement staff. NERC will be providing a series of webinars and workshops to guide compliance and enforcement staff at all levels on the application of FFT to PVs.

NERC also has posted information regarding the CEI implementation on its website. This information includes guidance to registered entities on information to be included in self-reports, particularly with respect to the underlying factual situation, the assessment of the risk to the reliability of the BPS and mitigating activities to correct and prevent PVs. NERC will continue to hold webinars and workshops with the industry to enhance understanding of FFT and the ERO's enforcement efforts. These webinars and workshops will focus on case studies based on the FFT informational filings to date.

In May of 2012, NERC will file with FERC a six-month status update on CEI implementation. In that filing, NERC will describe the experience gained and the results from implementation of the CEI to date. In a concurrent compliance filing, NERC will respond to specified compliance requirements outlined in the March 15th CEI order. Specifically, the six-month report will address and provide context for the CEI processing statistics, discuss the benefits obtained from the program from a broad perspective (NERC, RE and industry) and discuss implementation challenge and how NERC is addressing them. In preparation of this filing, NERC will be working with the REs to ensure their input is incorporated into the filing. NERC has also distributed a survey to solicit information from the registered entities regarding their experience with the implementation of the CEI to date that will also inform the content of the six-month update to FERC.

With additional efficiencies attained with the implementation of the FFT and spreadsheet NOP approach, NERC has been able to process a significant number of cases since September 2011. In the six-month period from September 2011 to the end of February 2012, as reflected in Figure 2, NERC filed 921 total violations, or on average 154 violations filed per month. Of the 921 violations, 428 were FFTs, representing an average filing rate of 71 FFTs per month. Over the past year, the ERO's caseload of active violations expanded from 3260 in February 2011 to 3611 in February 2012. The rate of new violations coming into the case load has increased dramatically from an average of 196 violations per month in February 2011 to an average of 267 violations per month in February 2012. The increase in caseload is primarily attributable to the large number of violations of CIP Standards that have been and will be entering the system.

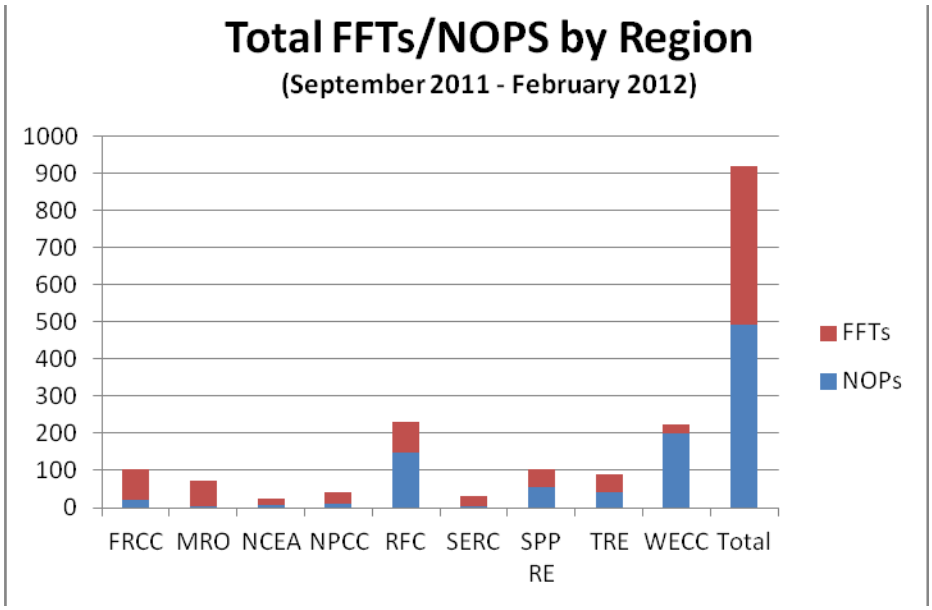
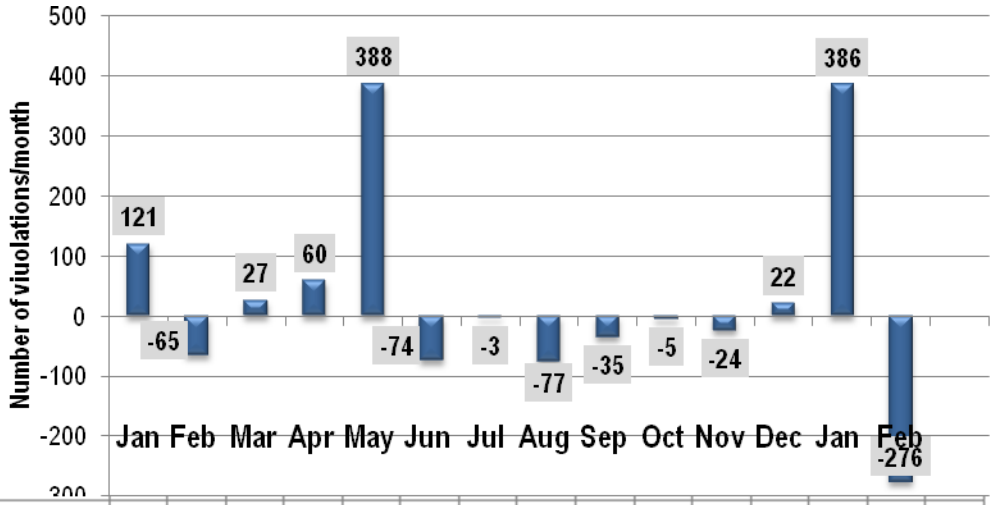



**Figure 17: Total FFTs/NOPS by Region**

The average monthly processing rate over the last year is 233 violations per month and includes both violations that are filed or dismissed. Figure 18 compares the number of incoming violations each month to the number of violations filed or dismissed. There have been more violations processed than submitted in seven of the last nine months. This is very encouraging and is primarily a result of the new compliance initiative introduced in September 2011.




| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| New | 218 | 212 | 190 | 219 | 581 | 223 | 211 | 166 | 262 | 247 | 212 | 203 | 545 | 131 | 3620 |
| Dismissed and Filed | 97 | 277 | 163 | 159 | 193 | 297 | 214 | 243 | 297 | 252 | 236 | 181 | 159 | 407 | 3175 |

**Figure 18: 2011 Violation Process Rate**

## Registered Entity Assessment

In 2011, NERC and the REs began work on a registered entity Assessment template. This assessment is being developed to establish a consistent basis for appropriately scoping compliance monitoring, to provide an opportunity for REs to work with entities on reliability

efforts and for registered entities to showcase their reliability efforts. Additionally, as a registered entity's Internal Compliance Program will be included in the assessment, the assessment may provide opportunities to identify and share strong Internal Compliance Program models.

The work that was conducted on the registered entity Assessments in 2011 generated significant discussion about what elements should be included in the registered entity assessment template. As a result, the ERO decided to provide more time to develop a template that would be widely accepted as an accurate representation of the entity's profile.

Therefore, in 2012 the ERO is looking to build a registered entity assessment template with direct input from the industry. The first half of 2012 will be dedicated to gathering information from the industry to create a template by the end of the year that will be phased-in though 2013.

### Human Performance

NERC has initiated a human performance program, to not only allow a more thorough analysis of the events on the BPS, but also to create a proactive focus on reducing human error and those precursory factors that allow human error to impact system reliability. The transfer of these important reliability messages requires a variety of instruments that can advise practices and training, particularly those that can affect the reliability of the BPS. Sharing across the North American industry allows expertise and experience to strengthen the grid as a whole, making everyone more successful in meeting reliability objectives. The techniques and procedures that NERC is using to propagate this initiative include conferences, workshops, webinars, and publications with facilitated active sharing among NERC and its stakeholders. A purposefully designed NERC sponsored Human Performance Conference is being planned for 2012 to address challenges related to human performance on the reliability of the BPS.

While human error is cited for a large part of the contributing causes for events on the BPS, the RRM is partnering with industry in the EA process and has initiated a new trending analysis system to assimilate the information received in entity reports. The process will aid in developing corresponding corrective action plans to address the causes of an event or failure. These corrective action plans will help to prevent reoccurrence of these events by creating the databases needed to apply the principles of effective risk management. After an investigation, analysis, or determination of causal factors of any event, RRM studies the event or occurrence, often leading to the identification of root causes and causal factors that could drive larger events on the BPS. These processes are applied to all levels of the ERO enterprise, including NERC, the REs, and industry participants that conduct event analysis and are involved in corrective action programs when a cause analysis is required. This process is designed to be a companion process to the ERO EA Process Manual. It is designed to assist those responsible for labeling and trending the causal factors and latent deficiencies leading to BPS events or failures.

### CAN Revision Process

Several CANs were in process at the time the NERC BOT instructed the NERC CAN team to revise all existing CANs in August 2011. Those CANs were re-initiated upon finalization of all existing CANs being rewritten and some were still in process at the end of 2011.

The CAN process was revised to illustrate that a CAN provides instructions to CEAs regarding the boundaries within which to assess compliance with standards and requirements. The process also states that a CAN cannot expand a standard and cannot add new requirements.

The CAN process was also revised to provide more opportunities for industry feedback and prioritization. The initial comment period for the revised CAN process was posted on the NERC web site, and industry provided feedback to improve the process. The feedback included requests for more detail on the CAN development process and to vet issues among the NERC executives from each division. Another request from industry stakeholders was to post all industry comments for transparency purposes. Other industry members recommended that NERC provide a method to inform Standards Drafting Teams (SDT) of issues in the CAN. In response, NERC provided the Standards Suggestion Form on the NERC web site. The NERC CAN team implemented the above recommendations and welcomes all feedback to continue improving the CAN process.

The NERC BOT recommended that NERC include a high-level review mechanism in the case that registered entity disagrees with the compliance guidance of a CAN. A review process was created whereby a registered entity or its representatives may submit technical evidence to have a CAN changed or removed. Another option is for the entity to propose a change to the standard through a request for a formal interpretation or a Standard Authorization Request (SAR). The entity may also request a higher-level review of the CAN.

The first review is by NERC's Chief Executive Officer, and the second level of review is by the BOTCC. Also, in accordance with the NERC ROP, a registered entity may contest a violation that was assessed due to the application of a CAN.

NERC is committed to continuing and further developing the CAN program in 2012.

### Rated System Path Methodology – MOD-029

MOD-029-1a became effective on April 1, 2011. FERC Order No. 729[49] has mandated that the MOD reliability standards be audited by the ERO[50] compliance enforcement authority The MOD reliability standards have been incorporated into the ERO's CMEP Implementation Plan as of June 1, 2011.[51]

[49] See Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the Bulk-Power System, 129 FERC ¶ 61,155 at P 106 (2009) (Order No. 729) (The Commission hereby adopts the NOPR proposal to direct the ERO to conduct an audit of the various implementation documents developed by transmission service providers to confirm that the complete available transfer capability methodologies reflected therein are sufficiently transparent to allow the Commission and others to replicate and verify those calculations.).

[50] Id. at P 131 (Upon further consideration, the Commission hereby directs the ERO to conduct these audits in the course of its periodic, three-year audits of users, owners and operators of the Bulk-Power System. The ERO shall begin this audit process 60 days after the implementation of these Reliability Standards.).

[51] The other MOD Reliability Standards, MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, and MOD-030-2 also became effective on April 1, 2011.

Prior to MOD-029-1a becoming effective, a number of registered entities within the Western Interconnection (the "WestConnect Utilities") submitted to NERC and WECC on February 24, 2011 a request for extension of time to comply with reliability standard MOD-029-1a. NERC granted an extension[52] of time for all entities subject to MOD-029-1a Requirement (R) 2.1. The basis for this extension was that the methodology contained within MOD-029-1a would, in certain cases, lead to Total Transfer Capability (TTC) and Available Transfer Capability (ATC) values significantly lower than those determined by registered entities under prior TTC calculation methodologies. MOD-029-1a Requirement 2.1 requires the use of power flow simulations to determine TTC:

> **R2.1.** Except where otherwise specified within MOD-029-1a, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

When a power flow simulation identifies a limiting piece of equipment that restricts the amount of flow on a path, that path is considered "Reliability Limited" and the TTC is set based on this limit. When a power flow simulation cannot sufficiently load the transmission path such that a reliability limit is encountered, the path is referred to as being "Flow Limited." Based upon the language of R2.1, the TTC should be equivalent to either the reliability limit or the flow limit for a path. The complication comes from situations in which the flow limit of a path artificially constrains a path's TTC below previously utilized levels for which registered entities have demonstrated reliable operations.

To account for this potential issue, NERC has delayed the implementation of requirement MOD-029-1a R2.1 for flow limited paths only, until such time that a modification to the reliability standard can be developed to mitigate the identified technical concern. Transmission Operators and Transmission Service Providers must comply with all other requirements of MOD-029-1a.

[52] See http://www.nerc.com/docs/compliance/MOD-029%20letter-AJR%202011MAR03.pdf

# Future of the CMEP

With the completion of the fourth year of mandatory compliance with NERC Reliability Standards, the CMEP has seen a large number of changes take place, and many more are in development for implementation in the coming years. One of the primary goals for 2011 is to transition the audit process away from documentation based standards towards risk and performance-based criteria. The details concerning these efforts are described next.

## Risk and Performance-Based Auditing

Beginning in 2011, it was the goal of NERC Compliance Operations to incorporate risk-based and performance-based components into future iterations of the implementation plan for the CMEP. Risk-based and performance-based audit criteria include six components for which the audit scope of a registered entity will be identified. The AML within the implementation plan of the CMEP will represent the minimum audit scope for any given registered entity, but based upon these risk and performance-based components, an audit scope can be expanded to include other reliability standards that are determined to be necessary by an RE after considering a registered entity in light of these components. The risk-based components, or criteria as they may also be called, are as follows:

- North American-wide NERC Reliability Standards most violated, including both all time historical and rolling twelve-month statistics, are considered. This encompasses the core standards to be monitored across the industry.
- RE specific most violated NERC Reliability Standards, which may include standards already identified above for some Regional Entities, or additional standards. This analysis allows REs to focus on significant trends and issues within the RE boundary. This also could lead to the identification of Interconnection-wide issues and concerns.
- RE reliability standards most violated, as applicable.
- Registered entity specific issues, including but not limited to operational issues, operational footprint changes, corporate restructuring, other trends, *etc*.
- Random determination (other high risk reliability standards, registered functions trends and concerns, standards rising in prominence and identified through trend analysis).
- Compliance culture, which considers the entity's compliance culture and overall strength of compliance.

The performance-based approach has two components. One component is the past performance of a registered entity as it relates to the operation of the BPS and the relative strength of the compliance controls in place to assure compliance. The second component includes a more detailed review and testing of the registered entity's programs and procedures to assure actual performance of the stated programs is being implemented, rather than relying solely on documentation.

REs will determine the registered entity's specific audit scope based upon the NERC AML and the six components listed above. The audit scope for registered entities that are registered for

performing identical "functions" will not always be identical across or within the REs. Registered entities will be advised of the audit scope when they receive the formal audit notice. Compliance information and data archived by the RE from the implementation of previous monitoring methods will be utilized in the development of a registered entity's audit scope, including but not limited to previous audits, self certifications, events, and previous or current enforcement actions.

## Implementation of Upcoming Standards

NERC Reliability Standards are in a constant state of change, from the release of new standards entirely to the issuance of new versions of existing standards, some of these changes have the potential for much greater impact to the CMEP than others. Of those that are particularly noteworthy for 2012 and beyond are:

### PER-003-1 Operating Personnel Credentials

This standard is an incremental improvement to PER-003-0 with United States enforcement beginning 10/1/2012. It expands on Version 0 of the standard by requiring specific areas of competency and certification for System Operators that are performing real-time operations related to Reliability Coordinator tasks, Transmission Operator Tasks, and Balancing Authority tasks. The standard is now much more explicit regarding the evidence required to demonstrate compliance with the standard. Entities will be expected to provide:

- A list of Real-time operating positions.
- A list of System Operators assigned to its Real-time operating positions.
- Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.
- A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

### FAC-008-3 Facility Ratings

This standard is an incremental improvement to FAC-008-1 with United States enforcement beginning 1/1/2013 (FAC-008-2 was never mandatory and enforceable in any jurisdiction). It retains much of the existing standard, but builds on some of the requirements and adds new requirements. Unlike FAC-008-1, which essentially holds the Generator Owner (GO) and the Transmission Owner (TO) to the same standard, FAC-008-3 has explicit requirements that require the applicable entities have detailed methodologies meeting certain criteria for the ratings of generators, the ratings of the generator lead lines, and the ratings of transmission facilities. These requirements are applicable to the GO, and the TO, respectively. Additionally, the standard now requires that entities implement those methodologies, and that they provide the resultant ratings to various other entities.

### FAC-013-2 Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon

This standard is a merging of, and an incremental improvement to, FAC-012-1 and FAC-013-1 with United States enforcement beginning April 1, 2013. In November of 2009, the FERC issued

Order No. 729, in which it directed the ERO to establish a standard that requires the calculation of transfer capabilities in the planning horizon, and ensure that the process used to calculate transfer capabilities in the planning horizon is consistent with the process used in the operating horizon. FERC set a deadline of January 28, 2011 for compliance with their order. In addition to retaining the key elements of FAC-012-1 and FAC-013-1, the new standard includes additional details regarding what is required to be considered within an entity's transfer Capability methodology, and provides an avenue through which entities may request supporting information related to the calculation of transfer capability.

### Actively Monitored List

Two noteworthy changes to the 2013 Implementation Plan include:

- Both audit scope and audit periodicity for a registered entity starts with the tier one and the usual audit schedule, but can be adjusted by the RE, with NERC oversight, based upon entity assessment.
- Self certifications of requirements are not necessary during an audit year where those requirements are being audited.

The emphasis in 2013 is moving the entire ERO toward performing quality registered entity assessments. A quality entity assessment includes a risk assessment, a careful look at internal controls, and details of an entity's internal compliance program (ICP). Internal controls are not only based on documentation, but also contain a performance aspect so that an entity is actively monitoring its own compliance. Emphasizing quality registered entity assessments are the key to performance based auditing. When there is confidence in entity assessments, both audit scopes and audit periodicity can be specifically tailored for each registered entity. In 2012 it was emphasized that Tier 1 standards represent minimum audit scope. However in 2013, if an entity's assessment indicates such, either an audit scope can be smaller than Tier 1 or audit periodicity can be reduced. This can allow for more compliance monitoring of entities which pose more risk to the reliability of the BES, which is the heart of performance monitoring.

NERC staff will continue to monitor recent events, such as the southwest cold snap event and the southwest blackout, and the progress of the FFT process as part of the CEI. To date, no changes have been necessary based on these factors. The substantive change in terms of compliance monitoring is that self certifications are not necessary from those entities undergoing an audit in a particular year for the standards requirements that are encompassed by the audit's scope.

# Appendix A – Actively Monitored Reliability Standards

The 2011 AML included a total of 39 reliability standards, encompassing 578 associated requirements, to be monitored for purposes of minimum compliance audit scope. In addition to audits, the AML defined the ERO's expectations for self-certifications to which registered entities certify compliance during the compliance year; self-certifications were set for 53 reliability standards and an associated 764 requirements. The ERO designated one reliability standard, encompassing two requirements, as subject to spot check. The following list details which of the reliability standards effective throughout 2011 were applicable to each of these different compliance discovery methods.

| 2011 CMEP Reliability Standards Summary | | | |
|---|---|---|---|
| Reliability Standards (FERC Approved) | Self-Certification Annual (A) | Annual Program Audit (X) | Spot Check (SC) |
| BAL-001-0.1a | | | |
| BAL-002-0 | | | |
| BAL-003-0.1b | | | |
| BAL-004-0 | | | |
| BAL-005-0.1b | | | |
| BAL-006-1.1 | | | |
| CIP-001-1 | A | X | |
| CIP-002-3, Effective 10/1/2010 | A | X | |
| CIP-003-3, Effective 10/1/2010 | A | X | |
| CIP-004-3, Effective 10/1/2010 | A | X | |
| CIP-005-3, Effective 10/1/2010 | A | X | |
| CIP-006-3c, Effective 10/1/2010 | A | X | |
| CIP-007-3, Effective 10/1/2010 | A | X | |
| CIP-008-3, Effective 10/1/2010 | A | X | |
| CIP-009-3, Effective 10/1/2010 | A | X | |
| COM-001-1.1 | A | X | |
| COM-002-2 | A | X | |
| EOP-001-0 | | | |
| EOP-002-2.1 | A | X | |
| EOP-003-1 | A | X | |
| EOP-004-1 | | | |
| EOP-005-1 | A | X | |
| EOP-006-1 | A | | |
| EOP-008-0 | A | X | |
| EOP-009-0 | | | |
| FAC-001-0 | A | | |

| 2011 CMEP Reliability Standards Summary | | | |
|---|---|---|---|
| Reliability Standards (FERC Approved) | Self-Certification Annual (A) | Annual Program Audit (X) | Spot Check (SC) |
| FAC-002-0 | | | |
| FAC-003-1 | A | X | |
| FAC-008-1 | A | X | |
| FAC-009-1 | A | X | |
| FAC-010-2.1 Effective 4/19/2010 | | | |
| FAC-011-2 Effective 4/29/2009 | | | |
| FAC-013-1 | | | |
| FAC-014-2 | A | | |
| INT-001-3 | | | |
| INT-003-2 | | | |
| INT-004-2 | | | |
| INT-005-3 Effective 7/1/2010 | | | |
| INT-006-3 Effective 7/1/2010 | | | |
| INT-007-1 | | | |
| INT-008-3 Effective 7/1/2010 | | | |
| INT-009-1 | | | |
| INT-010-1 | | | |
| IRO-001-1.1 | | | |
| IRO-002-1 | A | | |
| IRO-003-2 | A | | |
| IRO-004-1 | A | X | |
| IRO-005-2 | A | X | |
| IRO-006-4.1 | | | |
| IRO-014-1 | | | |
| IRO-015-1 | | | |
| IRO-016-1 | | | |
| MOD-001-1 Effective 4/1/2011 | A | X | |
| MOD-004-1 Effective 4/1/2011 | A | X | |
| MOD-006-0.1 Retired 3/31/2011 | | | |
| MOD-007-0 Retired 3/31/2011 | | | |
| MOD-008-1 Effective 4/1/2011 | A | X | |
| MOD-010-0 | | | |
| MOD-012-0 | | | |
| MOD-016-1.1 | | | |
| MOD-017-0.1 | | | |
| MOD-018-0 | | | |
| MOD-019-0.1 | | | |
| MOD-020-0 | | | |
| MOD-021-0.1 | | | |
| MOD-028-1 Effective 4/1/2011 | A | | |
| MOD-029-1 Effective 4/1/2011 | A | | |
| MOD-030-2 Effective 4/1/2011 | A | | |
| NUC-001-2 Effective 4/1/2010 | A | | SC |

| 2011 CMEP Reliability Standards Summary | | | |
|---|---|---|---|
| Reliability Standards (FERC Approved) | Self-Certification Annual (A) | Annual Program Audit (X) | Spot Check (SC) |
| PER-001-0.1 | A | | |
| PER-002-0 | A | X | |
| PER-003-0 | A | | |
| PER-004-1 | A | X | |
| PRC-001-1 | A | X | |
| PRC-004-1 | A | X | |
| PRC-005-1 | A | X | |
| PRC-007-0 | | | |
| PRC-008-0 | A | X | |
| PRC-009-0 | | | |
| PRC-010-0 | | | |
| PRC-011-0 | A | X | |
| PRC-015-0 | | | |
| PRC-016-0.1 | | | |
| PRC-017-0 | A | X | |
| PRC-018-1 | | | |
| PRC-021-1 | | | |
| PRC-022-1 | | | |
| PRC-023-1 Effective 7/1/2010 | A | X | |
| TOP-001-1 | A | | |
| TOP-002-2a | A | X | |
| TOP-003-0 | | | |
| TOP-004-2 | A | X | |
| TOP-005-1.1 | | | |
| TOP-006-1 | A | | |
| TOP-007-0 | | | |
| TOP-008-1 | | | |
| TPL-001-0.1 | A | | |
| TPL-002-0a | A | X | |
| TPL-003-0a Effective 4/23/2010 | A | X | |
| TPL-004-0 | | | |
| VAR-001-1 | A | X | |
| VAR-002-1.1b | A | X | |

# Appendix B – Compliance Audit Observation Report of Regional Entities

## Introduction and Audit Oversight Objectives

NERC compliance auditors maintain oversight of RE compliance audit teams throughout the entire audit process, pre-audit, on-site and post audit. NERC compliance auditors seek to capture compliance applications, positive observations, lessons learned, and recommendations. The primary purpose of the AAO Audit Oversight program is to focus on the compliance monitoring process; however, it is not to make determinations of compliance. NERC's audit oversights are designed to perform a thorough evaluation of the processes and criteria used by all REs in their determination of registered entities' compliance with the NERC Reliability Standards. During compliance audits, NERC staff may identify compliance applications[53], positive observations or good auditing practices, lessons learned, and recommendations. NERC communicates the results of its observations for feedback to REs, the development and revision of CANs, RSAWs, Compliance Process Bulletins, ERO auditor training, and compliance workshops for industry.

As NERC compliance auditors observe and participate in future compliance audits, NERC will provide continued compliance guidance to REs and registered entities through various methods. NERC summarizes such methods and compliance applications, positive observations, lessons learned, and recommendations in its 2011 Compliance Audit Observation Report of the REs.

## Selection Criteria

In 2011, NERC observed six RE led compliance audits. NERC AAO staff selected compliance audits of registered entities to observe. The 2011 audit observation scheduled included at least two audits within each RE in order to provide oversight to all REs in their conduct of compliance monitoring activities as well as to assist in the evaluation of the REs' consistent implementation of the CMEP.

Within each RE, AAO staff will prioritize the registered entities according to the following technical criteria:

- Organization & Structure – registered for a large number of functions, such as vertically integrated utilities
- Real Time Operations – registered for certified functions, especially Reliability Coordinators

[53] Compliance applications are identified through issues noted by NERC compliance auditors during an audit such that NERC should consider providing additional guidance to the Regional Entities and registered entities.

- System Size – includes such aspects as number of interconnections, circuit miles of transmission lines, transmission voltages, peak demand, etc.
- Generation Portfolio – includes number of generating units and type of fuel

In addition to technical criteria, AAO staff considered compliance history and issues surrounding a registered entity. Compliance history and issues refer to past and ongoing violations, investigations, BPS system events and associated spot checks.

## 2011 AAO Oversight Results

For 2011, NERC attended six RE led compliance audits of registered entities. From these, NERC identified eleven potential compliance applications. A compliance application is an issue that relates to a particular application of a reliability standard that may require additional scrutiny within the ERO in addition to guidance in the form of a CAN or otherwise to ensure consistent application. Of the potential compliance applications, noted, four concerned COM-002, two each were applicable to EOP-008 and EOP-005. Resolution of potential compliance applications followed communication with the NERC Reliability Standards department for future reliability standard revisions and consideration for CAN development.

### Positive Observations

Positive observations are aspects of the Regional Entities' audit approach that are noted by NERC observers during an audit to represent behaviors or actions that assist in the implementation of the CMEP. NERC considers and compares noteworthy practices applicable to all REs when determining a positive observation. Those noteworthy positive observations from 2011 follow.

### Status Update (Debrief) Tool

The compliance audit team uses a tool used for tracking of requirements covered with determinations of compliance and pending data requests. The tool is shared with the registered entity at the end of each day for officially submitting data requests and for providing the registered entity with a summary of audit progress based on the Reliability Standards reviewed.

### Daily Caucus and RSAW review with the Audit Team

The RE compliance audit sub-teams met together at least once a day. Each sub-team presents its RSAWs and the basis for its findings to the entire audit team. Collectively, the audit team makes the final determination of no finding or non-compliance. The daily caucus provides all audit team members the opportunity to fully understand any compliance issues.

### Enforcement Turnover

The RE audit team provides a detailed turnover to its enforcement group for any PVs identified during the audit. This turnover provides a narrative that describes the PV and includes references to evidence and data requests used to determine the PV.

### Just in Time Training

The RE requires all audit team members to complete the "Just-In-Time" training if audit team members have not completed the training in the last 90 days. The purpose of this training is to refresh fundamental concepts of auditing which supplements training required by NERC.

### Recommendations to the Audited Registered Entity

Upon completion of the audit and prior to the exit briefing, the RE compliance audit team holds a session with audited entity's compliance department personnel to discuss methods and recommendations for improving the registered entity's compliance program. This is done in conjunction of evaluating the registered entity's internal compliance program.

### Cross-training CIP auditors

The operations and planning compliance audit team included two CIP auditors who were provided the opportunity to learn the audit process and approach with non-CIP reliability standards and is an excellent method for enhancing the knowledge-base and experience of compliance auditors.

### FAC-008 and FAC-009 Facility Rating Methodology Checklist

The compliance audit team developed a spreadsheet-based checklist for FAC-008 and FAC-009 Facility Rating Methodology. The checklist ensures that all appropriate equipment is accounted for within an entity's facility rating methodology as required by FAC-008-1. Additionally, this checklist catalogs the locations within a registered entity's facility rating methodology relating to ratings for each type of equipment for easy reference when examining data as part of FAC-009-1.

### Index Tool for Evidence Identification

To facilitate the logistical considerations of submitted evidence, the RE compliance audit team uses an evidence index tool based upon a spreadsheet and includes this within their audit reports. The RE compliance audit team supplied the audited registered entity with this evidence index such that evidence submitted during the audit process would be cataloged by the registered entity. As a result, AAO staff noted that efficiency of the audit process was gained by both the RE compliance audit team, which did not need to expend its own resources on the cataloging of evidence, as well as for the registered entity, which used the evidence index numbers itself when referring to documentation.

### Interview Tracking Tools

The RE employees a tool to track questions developed during its pre-audit review to ask SMEs during the on-site audit. This tool functions as an effective interview audit plan to ensure that interviews are conducted in a methodical and efficient manner.

## Lessons Learned

Lessons learned are lessons identified by NERC compliance auditors during the practical execution of audit activities that are helpful for other audit teams to be mindful of during future audits to avoid potential problems and complications. The lessons learned item dealt with the audited entities lack of cohesive evidence. The lessons learned from 2011 audit oversight follow.

### Disjointed Documentation:

During the review of documentation for heavy standards, such as FAC-003 and FAC-008, it was found that the registered entity's associated plan and methodologies consisted of several documents rather than having one be all inclusive for each applicable standard or requirement. The documentation was further complicated by a lack of revision histories or references tying them together. Additionally, within its documentation, the entity referred to its regional criteria in many instances but in a haphazard manner, bringing about the situation where only some portions of a program, such as the entity's facility rating methodology, were consistent with these criteria. During the course of the audit, the audit team informed the entity that it should attempt to be consistent with its use and application of regional criteria. The audit team also made a suggestion on how to improve documentation during the audit closing presentation.

## Suggestions and Items for Consideration

During the audit process, NERC compliance auditors may notice difficulties encountered by RE audit teams or the registered entity being audited that impede the audit's efficiency or hamper an audit team's ability to determine compliance for a given requirement or reliability standard. As such, NERC recommendations provide compliance auditors guidance to prevent or mitigate re-occurrence of these difficulties in the future. Some of the notable recommendations follow.

### Same Corporate Umbrella - Auditing Multiple Registered Entities (different NCR numbers and entity names)

The audited entities referred to themselves in verbal accounts and in documentation with a number of different names which lead to some confusion among the audit team regarding evidence or RSAWs relating to one entity or another.

When this situation is unable to be avoided, AAO staff recommends the audit team should request one set of RSAWs from each entity even if there is to be only one audit report.

### Including Guidance within the Audit Notification Packet

The audited registered entity provided narratives in the RSAWs oftentimes did not make connections between requirements and documents used as evidence. More common was the complete absence of references altogether.

The RE compliance audit team mentioned that as part of a recent RE compliance workshop, the RE had provided guidance to those entities in attendance on best practices when completing RSAWs. The audited entity was not present at this workshop.

AAO staff recommends that the RE consider providing this information in either a condensed or complete format within the audit notification packet.

### Use of a daily debrief or status update tool

At the close of each day, the RE compliance audit team lead provided a daily debrief to the registered entity that included a verbal overview of the review status for the reliability standards that had been reviewed for the day.

AAO staff notes that a daily debrief is important for the registered entity and for the audit team. In addition to a review status for each standard within the audit scope, the debrief should include identified recommendations and submitted data requests, preferably in written form. This is especially important for audits utilizing multiple audit teams and scribes as other team members are completely reliant on the scribe and openness of the other audit sub-teams to share recommendations and data requests among the entire team. A written daily wrap-up of topics such as those mentioned would help ensure that no confusion or misunderstandings have occurred and that the full audit team is in agreement.

In order to enhance transparency of an audit for the audited entity and all audit team members, AAO staff recommends that RE enhance its daily debriefs with a summary document that lists all standards within the audit scope that clearly specifies the current status of each of those standards in terms of review. At a minimum, the status should describe whether a standard is under review, closed with no finding, or closed with a finding. Additionally, it is recommended that this summary document include the listing of data requests awaiting registered entity responses and tracks recommendations.

#### Interviewing Techniques

During a Subject Matter Expert (SME) interview, the RE compliance audit team member served as both the lead interviewer and the scribe. This led to some confusion and anxiety on the part of the SME when he finished responding to questions and was left waiting as the interviewer wrote notes without acknowledgement of the SME.

AAO staff recommends that the RE designate one audit team member as a lead interviewer and one as a dedicated scribe for each and every interview session to reduce burden on the registered entity in terms of SME time requirements.

#### Responsible Person for Presenting Evidence

During the SME evidence review for PRC-008-0 and PRC-023-1, the RE compliance audit team controlled the presentation of evidence, resulting in the SMEs directing the audit team to various documents and places within the documents while standing next to a projection screen. This format resulted in time delays and overall inefficient sessions as the SMEs were left waiting for audit team members to find and open documents as well as to find information within documents under SME direction.

AAO staff recommends that as a general practice, and especially for document and record intense reviews such as FAC-009, PRC-005, PRC-008, PRC-023, *etc.*, the RE compliance audit team have registered entity SMEs control the presentation of evidence in consideration of the fact that SMEs have greater familiarity with the evidence. The burden of demonstrating compliance lies with the registered entity, and this should extend to the provision of evidence as well as its presentation and explanation.

### Critical Infrastructure Department (CID)

The implementation by registered entities of compliance measures pertaining to CIP Standards 002—009 continued to mature in 2011, as did the assessment process performed by the ERO. There were no updates to the standards during the year, but the impact of changing standards

did contribute to the decision early in the year for CEAs to consider the standard audit period to be from October 1, 2010; *i.e.*, the effective date of version 3 of CIP Standards 002-009. This approach not only helped registered entities who did not have to focus on preparing and submitting audit evidence for multiple versions of the standards, but also enabled the CEAs to better manage most audits by approaching the review from a single reference point.

Another issue that impacted the assessment of compliance to the CIP Standards 002-009 during 2011 was the CANs that pertained to CIP Standards' requirements. Technologically complex requirements, often impacted by Technical Feasibility Exceptions (TFEs), made it necessary to complete various activities to support TFE assessments and audits according to guidance contained in applicable CANs. However, the long-term result of consistent evaluations remains the focus of the effort.

The ERO CIP auditors from all the Regional Entities continued their joint efforts to identify and resolve issues of common concern, with a goal of approaching issues consistently. The CIP Compliance Working Group (CCWG) used email conversations on the NERC list server with 40-50 messages a month, monthly conference calls, quarterly face to face meetings, and a sub-group dedicated to addressing TFE issues.

A unique opportunity for the CIP auditors presented itself in 2011 when they met with the 706 SDT as it continued work on version 5 of the CIP Standards. The meeting provided both groups a perspective on the work performed by their counterparts, and helped the 706 SDT identify ways to develop standards that are both practical and auditable.

### Technical Feasibility Exceptions (TFEs)

In Order No. 706, FERC directed that the ERO submit an annual report with a wide-area analysis regarding use of the TFEs and their impact on BPS reliability. The first "annual" report actually covered the first 18 months of the TFE program, and was submitted on September 30, 2011. Besides narrative content about the program, there were also numerous spreadsheets and tables with data regarding the quantities and types of TFEs that had been submitted, with related data pertaining to those requests.

Various aspects of the TFE program have been considered especially difficult to administer by registered entities and REs alike, in part because the program was developed before its full impact could be determined. As a result, the TFE Managers have identified areas of the TFE Procedure (Appendix 4D to NERC's Rules of Procedure) for which the group would like to propose changes.

### Sufficiency

CID's "Sufficiency Review Program" (SRP) grew in popularity and effectiveness in 2011. The SRP provides a "discussion-based dialogue" approach to examine an entity's Risk-Based Assessment Methodology (RBAM) and determine whether it is sufficient to ensure the secure, reliable operation of the BPS. The program reached ten BPS entities in 2011, and added value to the process by giving participants an update to support significant changes to the CIP Standards, in particular, CIP-002-4, Aurora, and including information pertaining to infrastructure protection from the Department of Homeland Security.

| 2011 Sufficiency Reviews | |
|---|---|
| **Entity** | **Date** |
| Dayton Power and Light (RFC) | June 20-24, 2011 |
| City of Independence Missouri (SPP) | July 11-12, 2011 |
| Pacific Gas and Electric (WECC) | July 25-29, 2011 |
| Orlando Utilities Commission (FRCC) | August 29th – September 2, 2011 |
| Louisiana Generating (SERC) | December 12-13, 2011 |
| Cottonwood Energy (SERC) | December 12-13, 2011 |
| Cabrillo Power I (WECC) | December 12-13, 2011 |
| Connecticut Jet Power (NPCC) | December 12-13, 2011 |
| Entergy Corporation (SERC) | December 14-16, 2011 |
| Black Hills Electric Cooperative (WECC) - *offsite* | December 19-21, 2011 |

### Auditor Training Activities

The NERC compliance auditors whose focus is CIP Standards 002 through 009 participated in various training activities during 2011. The Compliance Operations department led two training activities for both the ERO operations and planning compliance auditors, and the ERO CIP compliance auditors. The NERC CID group also led training that focused specifically on consistency and the CIP Standards audit process.

# Appendix C – Regulatory Actions

A list of NERC filings to FERC made in 2011 and FERC orders issued in 2011 can be found on the NERC website at http://www.nerc.com/page.php?cid=1|9|170.

# CAN Comment Form
# Compliance Application Notice – 0033

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

**Commenter Information**

Name: Guy Zito

Phone Number: 212-840-1070

Email Address: gzito@npcc.org

Entity Represented: Northeast Power Coordinating Council

Region: Northeast Power Coordinating Council

**Primary Interest Groups**

Are you suggesting a change to the groups mentioned? ~~Yes~~ / No
If yes, explain what change and why:

**Issue**

Are you suggesting a change to the issue statement of the CAN? ~~Yes~~ / No
If yes, explain what change and why:

**Background**

Are you suggesting a change to the background statement of the CAN? ~~Yes~~ / No

If yes, explain what change and why:

**Compliance Application**

Are you suggesting a change to the compliance application section of the CAN? Yes / ~~No~~

If yes, explain what change and why:

The draft CAN states:

> **"…**CEAs are to verify that when a GO, TO, or DP has used Criterion 1 to demonstrate compliance with Requirement R1 and does not have a 4-hour Facility Rating available, the entity has used the highest seasonal Facility Rating of a circuit for the available defined loading duration for any period 4 hours or greater…"

PRC-023-1 R1.1 states:

> **R1.1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

"Nearest" can include a duration less than 4 hours. The CAN is inappropriately defining the term "nearest 4 hours" to be "any period 4 hours or greater."

**Effective Period for CAN**

Are you suggesting a change to the effective period of the CAN? ~~Yes~~ / No

If yes, explain what change and why:

**Evidence of Compliance**

Are you suggesting a change to the evidence of compliance mentioned in the CAN? ~~Yes~~ / No

If yes, explain what change and why:

# CAN Comment Form
# Compliance Application Notice – 0044

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

**Commenter Information**

Name: Guy Zito

Phone Number: 212-840-1070

Email Address: gzito@npcc.org

Entity Represented: Northeast Power Coordinating Council

Region: Northeast Power Coordinating Council

**Primary Interest Groups**

Are you suggesting a change to the groups mentioned? ~~Yes~~ / No
If yes, explain what change and why:

**Issue**

Are you suggesting a change to the issue statement of the CAN? ~~Yes~~ / No
If yes, explain what change and why:

**Background**

Are you suggesting a change to the background statement of the CAN? ~~Yes~~ / No

If yes, explain what change and why:

**Compliance Application**

Are you suggesting a change to the compliance application section of the CAN? Yes / ~~No~~

If yes, explain what change and why:

The CAN uses the definition of the NERC Glossary term “Emergency” in defining actions the CEA should verify. The NERC Reliability Standard TOP-001 on the other hand does not include the NERC Glossary term “Emergency” as it uses the generic term “emergency”. By applying a NERC Glossary term that is not used in the Standards is inappropriate and exceeds the authority of the CAN process.

**Effective Period for CAN**

Are you suggesting a change to the effective period of the CAN? ~~Yes~~ / No

If yes, explain what change and why:

**Evidence of Compliance**

Are you suggesting a change to the evidence of compliance mentioned in the CAN? ~~Yes~~ / No

If yes, explain what change and why:

**From:** Monica Benson
**To:** monica.benson@nerc.net
**Subject:** NERC: Standards Bulletin - May 7-13, 2012
**Date:** Monday, May 07, 2012 9:55:33 AM

# Standards Bulletin
## May 7-13, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent FERC approvals and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting, Caroline Clouse with questions about CANs, and Mallory Huggins with feedback on this bulletin.

The current bulletin is always available on the Standards Under Development page, and previous bulletins are available on the Standards page.

If you would like to be added to the distribution list for a particular standards project to stay informed about drafting team meetings and calls, please email Mallory Huggins.

**STANDARDS ITEMS**

**Current Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2008-06: Cyber Security Order 706 (CIP-002-5 through CIP-0099-5, CIP-010-1, and CIP-011-1) – Open May 11-21, 2012 (Successive Ballots)

- Project 2007-03: Real-time Transmission Operations (TOP-001-2, TOP-002-3, TOP-003-2, and PRC-001-2) – Open April 27, 2012 - May 6, 2012 (Recirculation Ballot)

**Posted for Comment (comment periods close at 8 p.m. Eastern)**

- Project 2008-06: Cyber Security Order 706 (CIP-002-5 through CIP-0099-5, CIP-010-1, and CIP-011-1) – Open April 12, 2012 - May 21, 2012

    - Comment Form A: CIP-002 and CIP-003
    - Comment Form B: CIP-004 through CIP-007
    - Comment Form C: CIP-008 through CIP-001
    - Comment Form D: Definitions and Implementation Plans

- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Open April 25 - May 24, 2012 (Comment Form)

- Project 2007-02: Operating Personnel Communications Protocols (COM-003-2) – Open May 7 – June 20, 2012

**Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)**

- Project 2007-02: Operating Personnel Communications Protocols (COM-003-2) – Open May 7 – June 5, 2012

**Pending Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Open May 15-24, 2012 (Successive Ballot and Non-binding Poll)

**Standard Drafting Team Vacancies**

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the Drafting Team Vacancies page on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

The latest posted vacancy is for the following:

- Project 2010-13.2: Generator Relay Loadability: Seeking an individual with experience

in generator protection systems from the FRCC or MRO region and either the cooperative or merchant electricity generator sector.

**Call for Standards Development Project Candidates**

NERC is in the process of developing the 2013-2015 Reliability Standards Development Plan (the Plan). The Plan will be developed over the next several months, and will provide status updates for projects in development, identify the next projects scheduled for initiation, designate projects for further research, and catalog all proposed projects for future development.

- Summaries of the scope of each active project can be found in the 2012-2014 Plan, Appendix 4.
- Suggestions for a standards development project for the 2013-2015 Plan should be submitted via email to Andy Rodriquez using the new Suggestion Form no later than May 11, 2012.

**FERC Approvals and NERC Website Updates**

On April 19, 2012, FERC issued Order No. 761 – Version 4 Critical Infrastructure Protection Reliability Standards approving CIP-002-4: Cyber Security — Critical Cyber Asset Identification; CIP-003-4: Cyber Security — Security Management Controls; CIP-004-4: Cyber Security — Personnel & Training; CIP-005-4: Cyber Security — Electronic Security Perimeter(s); CIP-006-4: Cyber Security — Physical Security of Critical Cyber Assets; CIP-007-4: Cyber Security — Systems Security Management; CIP-008-4: Cyber Security — Incident Reporting and Response Planning; and CIP-009-4: Cyber Security — Recovery Plans for Critical Cyber Assets. The Order was published in the Federal Register on April 25, 2012 and will become effective on June 25, 2012. The standards will become enforceable in the United States on April 1, 2014.

The Reliability Standards page, Enforcement Dates page, complete set of Reliability Standards, and VRF and VSLs Matrices on NERC's website have been updated accordingly.

## OTHER ITEMS

**Compliance Application Notices (CANs) Posted for Comment**

- Comments due by May 7, 2012 to cancomments@nerc.net using the CAN Comment Form:

- CAN-0034: EOP-003 R1, IRO-002 R2, and TOP-001 R1, Use of Authority Letters (Draft with CCC Comments)

- CAN-0038: PER-002 R4, Training Hours (Draft with CCC Comments)

- Comments due by June 4, 2012 to cancomments@nerc.net using the CAN Comment Form:

  - CAN-0019: CIP-007 R3.2, Implementation of Software Security Patches or Upgrades (Draft with CCC Comments)

  - CAN-0023: CIP-005 R3 and CIP-006 R6, Logging System Failures (Draft with CCC Comments)

**Revised Definition of Adequate Level of Reliability (ALR) and Supporting Documents Posted for Comment**

- Comments on the following documents due by June 25, 2012:

  - Definition: Adequate Level of Reliability for the Bulk Electric System

  - Technical Report Supporting Definition of Adequate Level of Reliability

  - Discussion Paper: Risk Tolerance for Widespread Bulk Electric System Outages

  - Discussion Draft: Mapping of Adequate Level of Reliability for the Bulk Electric System to Standards Development Reliability Principles

  - *See also:* Original Announcement with background information on the Adequate Level of Reliability Task Force

- Submit comments using the electronic comment form.

**Upcoming Events**

- Standards Committee Communications and Planning Subcommittee Conference Call, May 8, 2012, 11:00 a.m.-12:30 p.m. Eastern (Agenda to be posted)

- Standards Committee Conference Call, May 10, 2012, 1:00-5:00 p.m. Eastern (Agenda)

- Project 2007-12: Frequency Response Technical Conferences

    1. May 22, 2012, 9:00 a.m.-5:00 p.m. Eastern, Crystal Gateway Marriott, Arlington, VA (Register)

    2. Project 2007-12: Frequency Response Technical Conference, May 24, 2012, 9:00 a.m.-5:00 p.m. Mountain, Xcel Energy Office, Denver, CO (Register)

- Save the Date: State of Standards Webinar, July 26, 2012, 1:00-5:00 p.m. Eastern

- Save the Date: Fall Reliability Standards and Compliance Workshop, October 23-25, 2012, Westin Buckhead, Atlanta, GA

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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**Suite 600, North Tower**
**Atlanta, GA 30326**
**404-446-2560 | www.nerc.com**

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**From:** Monica Benson
**To:** monica.benson@nerc.net
**Subject:** NERC: Standards Weekly Bulletin - May 14-20, 2012
**Date:** Monday, May 14, 2012 9:21:16 AM

# Standards Weekly Bulletin
# May 14-20, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent FERC approvals and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting, Ben Engelby with questions about CANs, and Mallory Huggins with feedback on this bulletin.

The current bulletin is always available on the Standards Under Development page, and previous bulletins are available on the Standards page.

If you would like to be added to the distribution list for a particular standards project to stay informed about drafting team meetings and calls, please email Mallory Huggins.

## STANDARDS ITEMS

### Current Ballots (ballot periods close at 8 p.m. Eastern)

- Project 2008-06: Cyber Security Order 706 (CIP-002-5 through CIP-0099-5, CIP-010-1, and CIP-011-1) – Open May 11-21, 2012 (Successive Ballots)

- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Open May 15-24, 2012 (Successive Ballot and Non-binding Poll)

### Posted for Comment (comment periods close at 8 p.m. Eastern)

- Project 2008-06: Cyber Security Order 706 (CIP-002-5 through CIP-0099-5, CIP-010-1, and CIP-011-1) – Open April 12, 2012 - May 21, 2012

- Comment Form A: CIP-002 and CIP-003
- Comment Form B: CIP-004 through CIP-007
- Comment Form C: CIP-008 through CIP-001
- Comment Form D: Definitions and Implementation Plans

- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Open April 25 - May 24, 2012 (Comment Form)
- Project 2007-02: Operating Personnel Communications Protocols (COM-003-1) – Open May 7 - June 20, 2012 (Comment Form)
- Cost Effective Analysis Process (CEAP) for NERC ERO Standards – Open May 7 - July 6, 2012 (Comment Form)
- Order 754 Request for Data or Information – Open May 11 - June 25, 2012 (Comment Form)

**Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)**

- Project 2007-02: Operating Personnel Communications Protocols (COM-003-1) – Open May 7 – June 5, 2012 (Join Ballot Pools for Initial Ballot and Non-binding Poll)

**Pending Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2007-02: Operating Personnel Communications Controls (COM-003-1) – June 11-20, 2012 (Initial Ballot and Non-binding Poll)

**Standard Drafting Team Vacancies**

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The latest posted vacancy is for the following:

- Project 2010-13.2: Generator Relay Loadability: Seeking an individual with experience in generator protection systems from the FRCC or MRO region and either the cooperative or merchant electricity generator sector.

## OTHER ITEMS

### Compliance Application Notices (CANs) Posted for Comment

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  - Discussion Draft: Mapping of Adequate Level of Reliability for the Bulk Electric System to Standards Development Reliability Principles
  - *See also:* Original Announcement with background information on the Adequate Level of Reliability Task Force

- Submit comments using the electronic comment form.

**Upcoming Events**

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  - May 22, 2012, 9:00 a.m.-5:00 p.m. Eastern, Crystal Gateway Marriott, Arlington, VA (Register)
  - Project 2007-12: Frequency Response Technical Conference, May 24, 2012, 9:00 a.m.-5:00 p.m. Mountain, Xcel Energy Office, Denver, CO (Register)
- Industry Webinars
  - Adequate Level of Reliability Task Force, May 23, 2012, 1:00-3:00 p.m. Eastern (Register)
  - Project 2007-02: Operating Personnel Communication Protocol (COM-003-1), June 7, 2012, 1:30-3:30 p.m. Eastern (Register)
- State of Standards Webinar, July 26, 2012, 1:00-5:00 p.m. Eastern (Register)
- Fall Reliability Standards and Compliance Workshop, October 23-25, 2012, Westin Buckhead, Atlanta, GA

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Standards Bulletin: May 21-27, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent FERC approvals and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting, Ben Engelby with questions about CANs, and Mallory Huggins with feedback on this bulletin.

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## STANDARDS ITEMS

**Current Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2008-06: Cyber Security Order 706 (CIP-002-5 through CIP-0099-5, CIP-010-1, and CIP-011-1) – Open May 11-21, 2012 (Successive Ballots)
- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Open May 15-24, 2012 (Successive Ballot and Non-binding Poll)

**Posted for Comment (comment periods close at 8 p.m. Eastern)**

- Project 2008-06: Cyber Security Order 706 (CIP-002-5 through CIP-0099-5, CIP-010-1, and CIP-011-1) – Open April 12, 2012 - May 21, 2012
  - Comment Form A: CIP-002 and CIP-003
  - Comment Form B: CIP-004 through CIP-007
  - Comment Form C: CIP-008 through CIP-001
  - Comment Form D: Definitions and Implementation Plans
- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Open April 25 - May 24, 2012 (Comment Form)
- Project 2007-02: Operating Personnel Communications Protocols (COM-003-1) – Open May 7 - June 20, 2012 (Comment Form)
- Cost Effective Analysis Process (CEAP) for NERC ERO Standards – Open May 7 - July 6, 2012 (Comment Form)
- Order 754 Request for Data or Information – Open May 11 - June 25, 2012 (Comment Form)
- Project 2007-06: System Protection Coordination (PRC-027-1) – Open May 21 – July 5, 2012 (Comment Form)

- Project 2011-INT-02: Interpretation of VAR-002 for Constellation – Open May 22 - June 20, 2012 (Comment Form)

**Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)**

- Project 2007-02: Operating Personnel Communications Protocols (COM-003-1) – Open May 7 – June 5, 2012 (Join Ballot Pools for Initial Ballot and Non-binding Poll)
- Project 2007-06: System Protection Coordination (PRC-027-1) – Open May 21 – July 5, 2012 (Join Ballot Pools for Initial Ballot and Non-binding Poll)

**Pending Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2007-02: Operating Personnel Communications Controls (COM-003-1) – June 11-20, 2012 (Initial Ballot and Non-binding Poll)
- Project 2011-INT-02: Interpretation of VAR-002 for Constellation – Open June 11-20, 2012 (Successive Ballot)
- Project 2007-06: System Protection Coordination (PRC-027-1) – Open June 26 – July 5, 2012 (Initial Ballot and Non-binding Poll)

**Standard Drafting Team Vacancies**

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the Drafting Team Vacancies page on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

The latest posted vacancy is for the following:

- Project 2010-13.2: Generator Relay Loadability: Seeking an individual with experience in generator protection systems from the FRCC or MRO region and either the cooperative or merchant electricity generator sector.

**Board of Trustees Approvals and NERC Website Updates**

On May 9, 2012, the NERC Board of Trustees adopted the following Reliability Standards: PRC-005-1.1b: Transmission and Generation Protection System Maintenance and Testing; TOP-001-2: Transmission Operations; TOP-002-3: Operations Planning; TOP-003-2: Operational Reliability Data; and VAR-001-3: Voltage and Reactive Control. The Board of Trustees also approved an interpretation to CIP-002 which resulted in CIP-002-3a: Cyber Security – Critical Asset Identification and CIP-002-4a: Cyber Security – Critical Cyber Asset Identification.

The Reliability Standards page, Enforcement Dates page, Complete Set of Reliability Standards, and VRF Matrix on NERC's website have been updated accordingly.

Note that FAC-003-3: Transmission Vegetation Management was also approved by NERC's Board of Trustees on May 9, 2012. The Reliability Standards page, Enforcement Dates page, Complete Set of

Reliability Standards, VRF Matrix, and Glossary of Terms on NERC's website will be updated accordingly later this week.

### FERC Approvals and NERC Website Updates

On May 7, 2012, FERC issued Order No. 763 – Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards approving EOP-003-2: Load Shedding Plans and PRC-006-1: Automatic Underfrequency Load Shedding. The Order was published in the Federal Register on May 11, 2012 and will become effective on July 10, 2012. The standards will become enforceable in the United States on October 1, 2013, except for Parts 4.1 through 4.6 of PRC-006-1 R4, as described in the Notes field on the Enforcement Dates page.

The Reliability Standards page, Enforcement Dates page, Complete Set of Reliability Standards, and VRF/VSL Matrices on NERC's website have been updated accordingly.

### Announcing a New Standards Email Address!

Beginning with today's bulletin, all major NERC standards communication will be issued from a new email address, NERC-StandardsAnnouncements-DoNotReply@nerc.net, rather than from individual NERC staff members' email addresses. This change will allow stakeholders to more easily sort and search for announcements issued from NERC's standards department. While the email address will be a "do not reply" address, all announcements will include information about whom to contact with questions, along with a hyperlink that pre-populates an email to the appropriate NERC staff member.

## OTHER ITEMS

### Compliance Application Notices (CANs) Posted for Comment

- Comments due by June 4, 2012 to cancomments@nerc.net using the CAN Comment Form:
  - CAN-0019: CIP-007 R3.2, Implementation of Software Security Patches or Upgrades (Draft with CCC Comments)
  - CAN-0023: CIP-005 R3 and CIP-006 R6, Logging System Failures (Draft with CCC Comments)

### Revised Definition of Adequate Level of Reliability (ALR) and Supporting Documents Posted for Comment

- Comments on the following documents due by June 25, 2012:
  - Definition: Adequate Level of Reliability for the Bulk Electric System
  - Technical Report Supporting Definition of Adequate Level of Reliability
  - Discussion Paper: Risk Tolerance for Widespread Bulk Electric System Outages
  - Discussion Draft: Mapping of Adequate Level of Reliability for the Bulk Electric System to Standards Development Reliability Principles
  - *See also:* Original Announcement with background information on the Adequate Level of Reliability Task Force

- Submit comments using the electronic comment form.

**Upcoming Events**

- Project 2007-12: Frequency Response Technical Conferences
  - May 22, 2012, 9:00 a.m.-5:00 p.m. Eastern, Crystal Gateway Marriott, Arlington, VA (Register)
  - Project 2007-12: Frequency Response Technical Conference, May 24, 2012, 9:00 a.m.-5:00 p.m. Mountain, Xcel Energy Office, Denver, CO (Register)
- Industry Webinars
  - Adequate Level of Reliability Task Force, May 23, 2012, 1:00-3:00 p.m. Eastern (Register)
  - Project 2007-02: Operating Personnel Communication Protocol (COM-003-1), June 7, 2012, 1:30-3:30 p.m. Eastern (Register)
- State of Standards Webinar, July 26, 2012, 1:00-5:00 p.m. Eastern (Register)
- Fall Reliability Standards and Compliance Workshop, October 23-25, 2012, Westin Buckhead, Atlanta, GA

**From:** NERC Standards Announcements (Do Not Reply)
**To:** monica.benson@nerc.net
**Subject:** NERC: Standards Bulletin - May 29 - June 3, 2012
**Date:** Tuesday, May 29, 2012 9:43:39 AM

# Standards Bulletin
## May 29- June 3, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent FERC approvals and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting, Ben Engelby with questions about CANs, and Mallory Huggins with feedback on this bulletin.

The current bulletin is always available on the Standards Under Development page, and previous bulletins are available on the Standards page.

If you would like to be added to the distribution list for a particular standards project to stay informed about drafting team meetings and calls, please email Mallory Huggins.

### STANDARDS ITEMS

**Posted for Comment (comment periods close at 8 p.m. Eastern)**

- Project 2007-02: Operating Personnel Communications Protocols (COM-003-1) – Open May 7 - June 20, 2012 (Comment Form)
- Cost Effective Analysis Process (CEAP) for NERC ERO Standards – Open May 7 - July 6, 2012 (Comment Form)
- Order 754 Request for Data or Information – Open May 11 - June 25, 2012 (Comment Form)
- Project 2011-INT-02: Interpretation of VAR-002 for Constellation – Open May 22 - June 20, 2012 (Comment Form)

- Project 2007-06: System Protection Coordination (PRC-027-1) – Open May 21 - July 5, 2012 (Comment Form)

- Project 2007-17: Protection System Maintenance & Testing – Open May 29 – June 27, 2012 (Comment Form)

**Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)**

- Project 2007-02: Operating Personnel Communications Protocols (COM-003-1) – Open May 7 – June 5, 2012 (Join Ballot Pools for Initial Ballot and Non-binding Poll)

- Project 2007-06: System Protection Coordination (PRC-027-1) – Open May 21 - June 19, 2012 (Join Ballot Pools for Initial Ballot and Non-binding Poll)

**Pending Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2007-02: Operating Personnel Communications Controls (COM-003-1) – June 11-20, 2012 (Initial Ballot and Non-binding Poll)

- Project 2011-INT-02: Interpretation of VAR-002 for Constellation – Open June 11-20, 2012 (Successive Ballot)

- Project 2007-06: System Protection Coordination (PRC-027-1) – Open June 26 - July 5, 2012 (Initial Ballot and Non-binding Poll)

- Project 2007-17: Protection System Maintenance & Testing – Open June 18 – 27, 2012 (Successive Ballot)

**Standard Drafting Team Vacancies**

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the Drafting Team Vacancies page on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

The latest posted vacancy is for the following:

- Project 2010-13.2: Generator Relay Loadability: Seeking an individual with experience in generator protection systems from the FRCC or MRO region and either the cooperative or merchant electricity generator sector.

**Board of Trustees Approvals and NERC Website Updates**

In addition to the May 9, 2012 Board of Trustees adoptions mentioned in last week's Standards Bulletin, the Board of Trustees also adopted Reliability Standard FAC-003-3: Transmission Vegetation Management, including two revised definitions.

The Reliability Standards page, Enforcement Dates page, Complete Set of Reliability Standards, Glossary of Terms, and VRF Matrix on NERC's website have been updated accordingly.

**FERC Approvals and NERC Website Updates**

*Correction:* On May 7, 2012, FERC issued Order No. 763 – Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards approving EOP-003-2: Load Shedding Plans and PRC-006-1: Automatic Underfrequency Load Shedding. The Order was published in the Federal Register on May 11, 2012 and will become effective on July 10, 2012. The standards will become enforceable in the United States on October 1, 2013, except for Parts 4.1 through 4.6 of PRC-006-1 R4, as described in the Notes field on the Enforcement Dates page. Last week's Standards Bulletin incorrectly stated the enforcement date in the United States as October 1, 2012. We regret the error.

**Announcing a New Standards Email Address!**

All major NERC standards communication will now be issued from a new email address, NERC-StandardsAnnouncements-DoNotReply@nerc.net, rather than from individual NERC staff members' email addresses. This change will allow stakeholders to more easily sort and search for announcements issued from NERC's standards department. While the email address will be a "do not reply" address, all announcements will include information about whom to contact with questions, along with a hyperlink that pre-populates an email to the appropriate NERC staff member.

Due to some technical issues with respect to the new email address, many stakeholders did not receive last week's Standards Bulletin; last week's bulletin is available on the Standards page and the email address issue has been corrected for this week.

## OTHER ITEMS

**Compliance Application Notices (CANs) Posted for Comment**

- Comments due by June 4, 2012 to cancomments@nerc.net using the CAN Comment Form:
  - CAN-0019: CIP-007 R3.2, Implementation of Software Security Patches or Upgrades (Draft with CCC Comments)
  - CAN-0023: CIP-005 R3 and CIP-006 R6, Logging System Failures (Draft with CCC Comments)

**Revised Definition of Adequate Level of Reliability (ALR) and Supporting Documents Posted for Comment**

- Comments on the following documents due by June 25, 2012:
  - Definition: Adequate Level of Reliability for the Bulk Electric System
  - Technical Report Supporting Definition of Adequate Level of Reliability
  - Discussion Paper: Risk Tolerance for Widespread Bulk Electric System Outages
  - Discussion Draft: Mapping of Adequate Level of Reliability for the Bulk Electric System to Standards Development Reliability Principles
  - *See also:* Original Announcement with background information on the Adequate Level of Reliability Task Force

- Submit comments using the electronic comment form.

**Upcoming Events**

- Industry Webinar: Project 2007-02: Operating Personnel Communication Protocol (COM-003-1), June 7, 2012, 1:30-3:30 p.m. Eastern (Register)
- State of Standards Webinar, July 26, 2012, 1:00-5:00 p.m. Eastern (Register)
- Fall Reliability Standards and Compliance Workshop, October 23-25, 2012, Westin Buckhead, Atlanta, GA

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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# Standards Bulletin: June 4-10, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent FERC approvals and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting, Ben Engelby with questions about CANs, and Mallory Huggins with feedback on this bulletin.

The current bulletin is always available on the Standards Under Development page, and previous bulletins are available on the Standards page.

If you would like to be added to the distribution list for a particular standards project to stay informed about drafting team meetings and calls, please email Mallory Huggins.

## STANDARDS ITEMS

**Posted for Comment (comment periods close at 8 p.m. Eastern)**

- Project 2007-12: Frequency Response (Technical Conferences) – Open May 30 - June 15, 2012 (Comment Form)
- Project 2007-02: Operating Personnel Communications Protocols (COM-003-1) – Open May 7 - June 20, 2012 (Comment Form)
- Order 754 Request for Data or Information – Open May 11 - June 25, 2012 (Comment Form)
- Project 2011-INT-02: Interpretation of VAR-002 for Constellation – Open May 22 - June 27, 2012 (Comment Form) – Updated Dates!
- Project 2007-17: Protection System Maintenance & Testing (PRC-005-2) – Open May 29 - June 27, 2012 (Comment Form)
- Project 2007-06: System Protection Coordination (PRC-027-1) – Open May 21 - July 5, 2012 (Comment Form)
- Cost Effective Analysis Process (CEAP) for NERC ERO Standards – Open May 7 - July 6, 2012 (Comment Form)
- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves – Open June 4 - July 3, 2012 (See Project page for Comment Forms) To be announced June 4th.

**Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)**

- Project 2007-02: Operating Personnel Communications Protocols (COM-003-1) – Open May 7 – June 5, 2012 (Join Ballot Pools for Initial Ballot and Non-binding Poll)
- Project 2007-06: System Protection Coordination (PRC-027-1) – Open May 21 - June 19, 2012 (Join Ballot Pools for Initial Ballot and Non-binding Poll)

**Pending Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2007-02: Operating Personnel Communications Controls (COM-003-1) – June 11-20, 2012 (Initial Ballot and Non-binding Poll)
- Project 2011-INT-02: Interpretation of VAR-002 for Constellation – Open June 18-27, 2012 (Successive Ballot) – Updated Dates!
- Project 2007-17: Protection System Maintenance & Testing (PRC-005-2) – Open June 18-27, 2012 (Successive Ballot)
- Project 2007-06: System Protection Coordination (PRC-027-1) – Open June 26 - July 5, 2012 (Initial Ballot and Non-binding Poll)

**Standard Drafting Team Vacancies**

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the Drafting Team Vacancies page on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

The latest posted vacancies are the following:

- Project 2007-02: Operating Personnel Communication: Seeking an individual from SERC or SPP with Transmission Operating Center, Reliability Coordinator, or Balancing Authority experience. Candidates should have experience developing verbal or written communication protocols for real-time operating personnel or managing real-time Bulk Electric System operations, or be a member of the Reliability Coordinator Working Group.
- Project 2010-13.2: Generator Relay Loadability: Seeking an individual with experience in generator protection systems from the FRCC or MRO region and either the cooperative or merchant electricity generator sector.

**Announcing a New Standards Email Address!**

All major NERC standards communication will now be issued from a new email address, NERC-StandardsAnnouncements-DoNotReply@nerc.net, rather than from individual NERC staff members' email addresses. This change will allow stakeholders to more easily sort and search for announcements issued from NERC's standards department. While the email address will be a "do not reply" address, all announcements will include information about whom to contact with questions, along with a hyperlink that pre-populates an email to the appropriate NERC staff member.

**Upcoming Posting: Revisions to Standard Processes Manual**

On June 18, 2012, revisions to NERC's Standard Processes Manual (and associated changes to the Rules of Procedure) will be posted for a 45-day comment period and ballot pool formation through August 2, 2012. The revisions were proposed by members of the Standards Committee Process Subcommittee in response to the recommendations of the stakeholder-driven Member Representatives Committee and Standards Process Input Group. Those recommendations were approved by NERC's Board of Trustees

on May 9, 2012 and are posted on the Standard Processes Manual Revisions to Implement SPIG Recommendations web page.

## OTHER ITEMS

### Compliance Application Notices (CANs) Posted for Comment

- Comments due by June 4, 2012 to cancomments@nerc.net using the CAN Comment Form:
  - CAN-0019: CIP-007 R3.2, Implementation of Software Security Patches or Upgrades (Draft with CCC Comments)
  - CAN-0023: CIP-005 R3 and CIP-006 R6, Logging System Failures (Draft with CCC Comments)

### Revised Definition of Adequate Level of Reliability (ALR) and Supporting Documents Posted for Comment

- Comments on the following documents due by June 25, 2012:
  - Definition: Adequate Level of Reliability for the Bulk Electric System
  - Technical Report Supporting Definition of Adequate Level of Reliability
  - Discussion Paper: Risk Tolerance for Widespread Bulk Electric System Outages
  - Discussion Draft: Mapping of Adequate Level of Reliability for the Bulk Electric System to Standards Development Reliability Principles
  - *See also:* Original Announcement with background information on the Adequate Level of Reliability Task Force
- Submit comments using the electronic comment form.

### Upcoming Events

- Industry Webinars
  - Order 754 Request for Data or Information, June 7, 2012, 11:00 a.m.-12:30 p.m. Eastern (Register)
  - Project 2007-02: Operating Personnel Communication Protocol (COM-003-1), June 7, 2012, 1:30-3:30 p.m. Eastern (Register)
  - State of Standards Webinar, July 26, 2012, 1:00-5:00 p.m. Eastern (Register)
- Fall Reliability Standards and Compliance Workshop, October 23-25, 2012, Westin Buckhead, Atlanta, GA

**From:** NERC Standards Announcements (Do Not Reply)
**To:** monica.benson@nerc.net
**Subject:** NERC: REVISED Standards Bulletin - June 11-17, 2012
**Date:** Monday, June 11, 2012 10:10:15 AM

# Standards Bulletin: Complete List June 11-17, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent FERC approvals and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting, Ben Engelby with questions about CANs, and Mallory Huggins with feedback on this bulletin.

The current bulletin is always available on the Standards Under Development page, and previous bulletins are available on the Standards page.

If you would like to be added to the distribution list for a particular standards project to stay informed about drafting team meetings and calls, please email Mallory Huggins.

## STANDARDS ITEMS

**Pending Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2007-02: Operating Personnel Communications Controls (COM-003-1) – June 11-20, 2012 (Initial Ballot and Non-binding Poll)

**Posted for Comment (comment periods close at 8 p.m. Eastern)**

- Project 2007-12: Frequency Response Technical Conferences – Open May 30 - June 15, 2012 (Comment Form)

- Project 2007-02: Operating Personnel Communications Protocols (COM-003-1) – Open May 7 - June 20, 2012 (Comment Form)

- Order 754 Request for Data or Information – Open May 11 - June 25, 2012 (Comment Form)

- Project 2011-INT-02: Interpretation of VAR-002 for Constellation – Open May 22 - June 27, 2012 (Comment Form) – Updated Dates!

- Project 2007-17: Protection System Maintenance & Testing (PRC-005-2) – Open May 29 - June 27, 2012 (Comment Form)

- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-001-1, BAL-002-2, BAL-012-1, BAL-013-1) – Open June 4 - July 3, 2012
  - BAL-001-1 (Comment Form)
  - BAL-002-2 (Comment Form)
  - BAL-012-1 (Comment Form)
  - BAL-013-1 (Comment Form)

- Project 2007-06: System Protection Coordination (PRC-027-1) – Open May 21 - July 5, 2012 (Comment Form)

- Cost Effective Analysis Process (CEAP) for NERC ERO Standards – Open May 7 - July 6, 2012 (Comment Form)

- Project 2006-06: Reliability Coordination (COM-001-2, COM-002-3, IRO-001-3) – Open June 7, 2012 - July 6, 2012 (Comment Form)

**Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)**

- Project 2007-06: System Protection Coordination (PRC-027-1) – Open May 21 - June 19, 2012 (Join Ballot Pools for Initial Ballot and Non-binding Poll)

**Pending Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2011-INT-02: Interpretation of VAR-002 for Constellation – Open June 18-27,

2012 (Successive Ballot) – Updated Dates!

- Project 2007-17: Protection System Maintenance & Testing (PRC-005-2) – Open June 18-27, 2012 (Successive Ballot)

- Project 2007-06: System Protection Coordination (PRC-027-1) – Open June 26 - July 5, 2012 (Initial Ballot and Non-binding Poll)

- Project 2006-06: Reliability Coordination (COM-002-3, IRO-001-3) – Open June 27, 2012-July 6, 2012 (Recirculation Ballot and Non-binding Poll)

- Project 2006-06: Reliability Coordination (COM-001-2) – Open June 27, 2012-July 6, 2012 (Successive Ballot and Non-binding Poll)

**Board of Trustees Approvals and NERC Website Updates**
In addition to the May 9, 2012 Board of Trustees adoptions mentioned in previous bulletins, the Board of Trustees also adopted Reliability Standard PRC-001-2 — System Protection Coordination.

The Reliability Standards page, Enforcement Dates page, Complete Set of Reliability Standards, and VRF Matrix on NERC's website have been updated accordingly.

**FERC Approvals and NERC Website Updates**
On May 31, 2012, FERC issued an Order approving Regional Reliability Standard IRO-006-TRE-1— IROL and SOL Mitigation in the ERCOT Region. The order became effective on May 31, 2012 and the standard will become enforceable on July 1, 2012.

The Reliability Standards page, Enforcement Dates page, Complete Set of Reliability Standards, and VRF Matrix on NERC's website have been updated accordingly. The VSL Matrix was updated for IRO-006-TRE-1.

**Standard Drafting Team Vacancies**

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the Drafting Team Vacancies page on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

The latest posted vacancies are the following:

- Project 2007-02: Operating Personnel Communication: Seeking an individual from

SERC or SPP with Transmission Operating Center, Reliability Coordinator, or Balancing Authority experience. Candidates should have experience developing verbal or written communication protocols for real-time operating personnel or managing real-time Bulk Electric System operations, or be a member of the Reliability Coordinator Working Group.

- Project 2010-13.2: Generator Relay Loadability: Seeking an individual with experience in generator protection systems from the MRO region and either the cooperative or merchant electricity generator sector.

**Upcoming Posting: Revisions to Standard Processes Manual**

On June 18, 2012, revisions to NERC's Standard Processes Manual and associated changes to the Rules of Procedure will be posted for a 30-day comment period and ballot pool formation through July 17, 2012. (Note that this is a change from the original planned 45-day comment period.) The revisions were proposed by members of the Standards Committee Process Subcommittee in response to the recommendations of the stakeholder-driven Member Representatives Committee and Standards Process Input Group. Those recommendations were approved by NERC's Board of Trustees on May 9, 2012 and are posted on the Standard Processes Manual Revisions to Implement SPIG Recommendations web page.

## OTHER ITEMS

**Compliance Application Notices (CANs) Posted for Comment**

- Comments due by June 29, 2012 to cancomments@nerc.net using the CAN Comment Form:
  - CAN-0033: PRC-023 Transmission Relay Loadability Criteria Selection (Draft CAN)
  - CAN-0044: TOP-001 Operating Emergencies and Emergency Conditions (Draft CAN)

**Revised Definition of Adequate Level of Reliability (ALR) and Supporting Documents Posted for Comment**

- Comments on the following documents due by June 25, 2012:
  - Definition: Adequate Level of Reliability for the Bulk Electric System
  - Technical Report Supporting Definition of Adequate Level of Reliability
  - Discussion Paper: Risk Tolerance for Widespread Bulk Electric System Outages
  - Discussion Draft: Mapping of Adequate Level of Reliability for the Bulk Electric System to Standards Development Reliability Principles
  - *See also:* Original Announcement with background information on the Adequate Level of Reliability Task Force
- Submit comments using the electronic comment form.

**Upcoming Events**

- Standards Committee Conference Calls
  - Standards Committee Communications and Planning Subcommittee Conference Call, June 12, 2012, 11:00 a.m.-12:30 p.m. (Agenda)
  - Standards Committee Conference Call, June 14, 2012, 1:00-5:00 p.m. Eastern (Agenda)
- Industry Webinars
  - Standard Processes Manual Revisions to Implement SPIG Recommendations Webinar, June 25, 2012, 2:00-4:00 p.m. Eastern (Register)
  - State of Standards Webinar, July 26, 2012, 1:00-5:00 p.m. Eastern (Register)
- Fall Reliability Standards and Compliance Workshop, October 23-25, 2012, Westin Buckhead, Atlanta, GA

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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**From:** NERC Standards Announcements (Do Not Reply)
**To:** monica.benson@nerc.net
**Subject:** NERC: Standards Bulletin - June 11-17, 2012
**Date:** Monday, June 11, 2012 8:53:45 AM

# Standards Bulletin
# June 11-17, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent FERC approvals and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting, Ben Engelby with questions about CANs, and Mallory Huggins with feedback on this bulletin.

The current bulletin is always available on the Standards Under Development page, and previous bulletins are available on the Standards page.

If you would like to be added to the distribution list for a particular standards project to stay informed about drafting team meetings and calls, please email Mallory Huggins.

## STANDARDS ITEMS

**Pending Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2007-02: Operating Personnel Communications Controls (COM-003-1) – June 11-20, 2012 (Initial Ballot and Non-binding Poll)

**Posted for Comment (comment periods close at 8 p.m. Eastern)**

- Project 2007-12: Frequency Response Technical Conferences – Open May 30 - June 15, 2012 (Comment Form)

- Project 2007-02: Operating Personnel Communications Protocols (COM-003-1) – Open May 7 - June 20, 2012 (Comment Form)

- Order 754 Request for Data or Information – Open May 11 - June 25, 2012 (Comment Form)

- Project 2011-INT-02: Interpretation of VAR-002 for Constellation – Open May 22 - June 27, 2012 (Comment Form) – Updated Dates!

- Project 2007-17: Protection System Maintenance & Testing (PRC-005-2) – Open May 29 - June 27, 2012 (Comment Form)

- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-001-1, BAL-002-2, BAL-012-1, BAL-013-1) – Open June 4 - July 3, 2012
  - BAL-001-1 (Comment Form)
  - BAL-002-2 (Comment Form)
  - BAL-012-1 (Comment Form)
  - BAL-013-1 (Comment Form)

- Project 2007-06: System Protection Coordination (PRC-027-1) – Open May 21 - July 5, 2012 (Comment Form)

- Cost Effective Analysis Process (CEAP) for NERC ERO Standards – Open May 7 - July 6, 2012 (Comment Form)

- Project 2006-06: Reliability Coordination (COM-001-2, COM-002-3, IRO-001-3) – Open June 27, 2012 - July 6, 2012 (Comment Form)

**Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)**

- Project 2007-06: System Protection Coordination (PRC-027-1) – Open May 21 - June 19, 2012 (Join Ballot Pools for Initial Ballot and Non-binding Poll)

**Pending Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2011-INT-02: Interpretation of VAR-002 for Constellation – Open June 18-27,

2012 (Successive Ballot) – Updated Dates!

- Project 2007-17: Protection System Maintenance & Testing (PRC-005-2) – Open June 18-27, 2012 (Successive Ballot)

- Project 2007-06: System Protection Coordination (PRC-027-1) – Open June 26 - July 5, 2012 (Initial Ballot and Non-binding Poll)

- Project 2006-06: Reliability Coordination (COM-002-3, IRO-001-3) – Open June 27, 2012-July 6, 2012 (Recirculation Ballot and Non-binding Poll)

- Project 2006-06: Reliability Coordination (COM-001-2) – Open June 27, 2012-July 6, 2012 (Successive Ballot and Non-binding Poll)

**Board of Trustees Approvals and NERC Website Updates**
In addition to the May 9, 2012 Board of Trustees adoptions mentioned in previous bulletins, the Board of Trustees also adopted Reliability Standard PRC-001-2 — System Protection Coordination.

The Reliability Standards page, Enforcement Dates page, Complete Set of Reliability Standards, and VRF Matrix on NERC's website have been updated accordingly.

**FERC Approvals and NERC Website Updates**
On May 31, 2012, FERC issued an Order approving Regional Reliability Standard IRO-006-TRE-1— IROL and SOL Mitigation in the ERCOT Region. The order became effective on May 31, 2012 and the standard will become enforceable on July 1, 2012.

The Reliability Standards page, Enforcement Dates page, Complete Set of Reliability Standards, and VRF Matrix on NERC's website have been updated accordingly. The VSL Matrix was updated for IRO-006-TRE-1.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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**From:** NERC Standards Announcements (Do Not Reply)
**To:** monica.benson@nerc.net
**Subject:** NERC: Standards Bulletin - June 18-24, 2012
**Date:** Monday, June 18, 2012 9:07:01 AM

# Standards Bulletin
## June 18-24, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent FERC approvals and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting, Ben Engelby with questions about CANs, and Mallory Huggins with feedback on this bulletin.

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### STANDARDS ITEMS

**Current Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2007-02: Operating Personnel Communications Controls (COM-003-1) – June 11-20, 2012 (Initial Ballot and Non-binding Poll)
- Project 2011-INT-02: Interpretation of VAR-002 for Constellation – Open June 18-27, 2012 (Successive Ballot)
- Project 2007-17: Protection System Maintenance & Testing (PRC-005-2) – Open June 18-27, 2012 (Successive Ballot)

**Posted for Comment (comment periods close at 8 p.m. Eastern)**

- Project 2007-02: Operating Personnel Communications Protocols (COM-003-1) – Open May 7 - June 20, 2012 (Comment Form)

- Order 754 Request for Data or Information – Open May 11 - June 25, 2012 (Comment Form)

- Project 2011-INT-02: Interpretation of VAR-002 for Constellation – Open May 22 - June 27, 2012 (Comment Form)

- Project 2007-17: Protection System Maintenance & Testing (PRC-005-2) – Open May 29 - June 27, 2012 (Comment Form)

- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-001-1, BAL-002-2, BAL-012-1, BAL-013-1) – Open June 4 - July 3, 2012

  - BAL-001-1 (Comment Form)

  - BAL-002-2 (Comment Form)

  - BAL-012-1 (Comment Form)

  - BAL-013-1 (Comment Form)

- Project 2007-06: System Protection Coordination (PRC-027-1) – Open May 21 - July 5, 2012 (Comment Form)

- Cost Effective Analysis Process (CEAP) for NERC ERO Standards – Open May 7 - July 6, 2012 (Comment Form)

- Project 2006-06: Reliability Coordination (COM-001-2, COM-002-3, IRO-001-3) – Open June 7, 2012 - July 6, 2012 (Comment Form)

- Interpretation 2010-INT-01: Interpretation of TOP-006-2 R1.2 and R3 for FMPP – Open June 14 - July 30, 2012 (Comment Form)

- Request for Data or Information: Order No. 762 Transmission System Performance Following Loss of a Single Bulk Electric System Element – Open June 19 - July 9, 2012 (Comment Form – Coming Soon)

- Standard Processes Manual Revisions to Implement SPIG Recommendations – Open

June 19 - July 18, 2012 (all documents and the comment form will be posted on Tuesday, June 19)

**Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)**

- Project 2007-06: System Protection Coordination (PRC-027-1) – Open May 21 - June 19, 2012 (Join Ballot Pools for Initial Ballot and Non-binding Poll)
- Interpretation 2010-INT-01: Interpretation of TOP-006-2 R1.2 and R3 for FMPP – Open June 14 - July 13, 2012 (Join Ballot Pools for Initial Ballot and Non-binding Poll)

**Pending Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2007-06: System Protection Coordination (PRC-027-1) – Open June 26 - July 5, 2012 (Initial Ballot and Non-binding Poll)
- Project 2006-06: Reliability Coordination (COM-002-3, IRO-001-3) – Open June 27, 2012-July 6, 2012 (Recirculation Ballot and Non-binding Poll)
- Project 2006-06: Reliability Coordination (COM-001-2) – Open June 27, 2012-July 6, 2012 (Successive Ballot and Non-binding Poll)
- Interpretation 2010-INT-01: Interpretation of TOP-006-2 R1.2 and R3 for FMPP – Open July 20-30, 2012 (Initial Ballot and Non-binding Poll)

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The latest posted vacancies are the following:

- Project 2007-02: Operating Personnel Communication: Seeking an individual from SERC or SPP with Transmission Operating Center, Reliability Coordinator, or Balancing

Authority experience. Candidates should have experience developing verbal or written communication protocols for real-time operating personnel or managing real-time Bulk Electric System operations, or be a member of the Reliability Coordinator Working Group.

- Project 2010-13.2: Generator Relay Loadability: Seeking an individual with experience in generator protection systems from the MRO region and either the cooperative or merchant electricity generator sector.

## OTHER ITEMS

**Revised Definition of Adequate Level of Reliability (ALR) and Supporting Documents Posted for Comment**

- Comments on the following documents due by June 25, 2012:
  - Definition: Adequate Level of Reliability for the Bulk Electric System
  - Technical Report Supporting Definition of Adequate Level of Reliability
  - Discussion Paper: Risk Tolerance for Widespread Bulk Electric System Outages
  - Discussion Draft: Mapping of Adequate Level of Reliability for the Bulk Electric System to Standards Development Reliability Principles
  - *See also:* Original Announcement with background information on the Adequate Level of Reliability Task Force
- Submit comments using the electronic comment form.

**Compliance Application Notices (CANs) Posted for Comment**

- Comments due by July 9, 2012 (note extended comment period) to cancomments@nerc.net using the CAN Comment Form:
  - CAN-0033: PRC-023 Transmission Relay Loadability Criteria Selection (Draft

CAN)

- CAN-0044: TOP-001 Operating Emergencies and Emergency Conditions (Draft CAN)

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**Upcoming Events**

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  - State of Standards Webinar, July 26, 2012, 1:00-5:00 p.m. Eastern (Register)
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You have received this email because you are a registered representative in the Registered Ballot Body.

**From:** NERC Standards Announcements (Do Not Reply)
**To:** monica.benson@nerc.net
**Subject:** NERC: Standards Bulletin - June 25 - July 1, 2012
**Date:** Monday, June 25, 2012 8:57:31 AM

# Standards Bulletin

## June 25 – July 1, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent FERC approvals and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting, Ben Engelby with questions about CANs, and Mallory Huggins with feedback on this bulletin.

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### STANDARDS ITEMS

**Current Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2011-INT-02: Interpretation of VAR-002 for Constellation – Open June 18-27, 2012 (Successive Ballot)
- Project 2007-17: Protection System Maintenance & Testing (PRC-005-2) – Open June 18-27, 2012 (Successive Ballot)
- Project 2007-06: System Protection Coordination (PRC-027-1) – Open June 26 - July 5, 2012 (Initial Ballot and Non-binding Poll)

**Posted for Comment (comment periods close at 8 p.m. Eastern)**

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- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-001-1, BAL-002-2, BAL-012-1, BAL-013-1) – Open June 4 - July 3, 2012
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- Cost Effective Analysis Process (CEAP) for NERC ERO Standards – Open May 7 - July 6, 2012 (Comment Form)
- Draft Request for Data or Information: Order No. 762 Transmission System Performance Following Loss of a Single Bulk Electric System Element – Open June 19 - July 9, 2012 (Comment Form)
- Standard Processes Manual Revisions to Implement SPIG Recommendations – Open June 20 - July 19, 2012 (Comment Form)
- Interpretation 2012-INT-02: Interpretation of TPL-003-0a and TPL-004-0 for SPCS – Open June 20 - July 19, 2012 (Comment Form)
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- Project 2012-08.1: Phase 1 of Glossary Updates: Statutory Definitions – Open June 19 - August 2, 2012 (Comment Form)

**Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)**

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- Project 2012-08.1: Phase 1 of Glossary Updates: Statutory Definitions – Open June 19 - July 18, 2012 (Join Ballot Pool)

**Pending Ballots (ballot periods close at 8 p.m. Eastern)**

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- Project 2007-12: Frequency Response: Seeking individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

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  - Discussion Paper: Risk Tolerance for Widespread Bulk Electric System Outages
  - Discussion Draft: Mapping of Adequate Level of Reliability for the Bulk Electric System to Standards Development Reliability Principles
  - *See also:* Original Announcement with background information on the Adequate Level of Reliability Task Force
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- CAN-0044: TOP-001 Operating Emergencies and Emergency Conditions (Draft CAN)

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  - Standard Processes Manual Revisions to Implement SPIG Recommendations Webinar, June 25, 2012, 2:00-4:00 p.m. Eastern (Register)
  - State of Standards Webinar, July 26, 2012, 1:00-5:00 p.m. Eastern (Register)
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**From:** NERC Standards Announcements (Do Not Reply)
**To:** monica.benson@nerc.net
**Subject:** NERC: Standards Bulletin - July 2-8, 2012
**Date:** Monday, July 02, 2012 9:40:42 AM

# Standards Bulletin
## July 2-8, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards items posted for industry comment or ballot, along with recent FERC approvals and upcoming standards-related postings and events. Please email Monica Benson with questions about standards commenting and balloting, Ben Engelby with questions about CANs, and Mallory Huggins with feedback on this bulletin.

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### STANDARDS ITEMS

**Current Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2007-06: System Protection Coordination (PRC-027-1) – Open June 26 - July 5, 2012 (Initial Ballot and Non-binding Poll)
- Project 2006-06: Reliability Coordination (COM-002-3 and IRO-001-3) – Open June 27 - July 6, 2012 (Recirculation Ballot and Non-binding Poll)
- Project 2006-06: Reliability Coordination (COM-001-2) – Open June 27 - July 6, 2012 (Successive Ballot and Non-binding Poll)

**Posted for Comment (comment periods close at 8 p.m. Eastern)**

- Project 2010-14.1: Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-001-1, BAL-002-2, BAL-012-1, BAL-013-1) – Open June 4 - July 3, 2012
  - BAL-001-1 (Comment Form)
  - BAL-002-2 (Comment Form)
  - BAL-012-1 (Comment Form)
  - BAL-013-1 (Comment Form)
- Project 2007-06: System Protection Coordination (PRC-027-1) – Open May 21 - July 5, 2012 (Comment Form)
- Cost Effective Analysis Process (CEAP) for NERC ERO Standards – Open May 7 - July 6, 2012 (Comment Form)
- Project 2006-06: Reliability Coordination (COM-001-2) – Open June 7 - July 6, 2012 (Comment Form)
- Draft Request for Data or Information: Order No. 762 Transmission System Performance Following Loss of a Single Bulk Electric System Element – Open June 19 - July 9, 2012 (Comment Form)
- Standard Processes Manual Revisions to Implement SPIG Recommendations – Open June 20 - July 19, 2012 (Comment Form)
- Interpretation 2012-INT-02: Interpretation of TPL-003-0a and TPL-004-0 for SPCS – Open June 20 - July 19, 2012 (Comment Form)
- Interpretation 2012-INT-05: Interpretation of CIP-002-2 for OGE – Open June 27- July 27, 2012 (Comment Form)
- Interpretation 2010-INT-01: Interpretation of TOP-006-2 R1.2 and R3 for FMPP – Open June 14 - July 30, 2012 (Comment Form)
- Project 2012-08.1: Phase 1 of Glossary Updates: Statutory Definitions – Open June 19 - August 2, 2012 (Comment Form)

**Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)**

- Interpretation 2010-INT-01: Interpretation of TOP-006-2 R1.2 and R3 for FMPP – Open June 14 - July 13, 2012 (Join Ballot Pools for Initial Ballot and Non-binding Poll)

- Project 2012-08.1: Phase 1 of Glossary Updates: Statutory Definitions – Open June 19 - July 18, 2012 (Join Ballot Pool)

**Pending Ballots (ballot periods close at 8 p.m. Eastern)**

- Interpretation 2010-INT-01: Interpretation of TOP-006-2 R1.2 and R3 for FMPP – Open July 20-30, 2012 (Initial Ballot and Non-binding Poll)

- Project 2012-08.1: Phase 1 of Glossary Updates: Statutory Definitions – Open July 24 - August 2, 2012 (Initial Ballot)

**Background Information for Upcoming P81 Standards Project Posting**

In its March 15, 2012 order on NERC's Find, Fix, and Track process (138 FERC ¶ 61,193), FERC included a paragraph (paragraph 81) indicating its interest in obtaining views from NERC, the Regional Entities, and other interested parties about reliability standards or requirements within reliability standards that provide little protection for the Bulk-Power System or are redundant. A core team consisting of industry representatives led by EEI and LPPC trade associations, Regional Entities, and NERC, referred to as the P81 team, is working to establish a list of requirements to be considered for retirement.

The team has been conducting a concentrated effort to expeditiously respond to the opportunity presented in the order and will be submitted a Standard Authorization Request (SAR) to address this project at the July 11-12 Standards Committee meeting. The SAR posting will provide more information regarding the phased structure of the project and will provide the opportunity for wider industry input on the list of potential requirements to retire in the initial phase, as well as the criteria the team used for determining whether a requirement may be eligible for removal.

As the SAR is finalized and work continues on the P81 project, NERC will continue to update stakeholders in this bulletin and elsewhere.

**Standard Drafting Team Vacancies**

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the Drafting Team Vacancies page on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

- Project 2007-02: Operating Personnel Communication: Seeking an individual from SERC or SPP with Transmission Operating Center, Reliability Coordinator, or Balancing Authority experience. Candidates should have experience developing verbal or written communication protocols for real-time operating personnel or managing real-time Bulk Electric System operations, or be a member of the Reliability Coordinator Working Group.

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- Project 2007-12: Frequency Response: Seeking individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

## OTHER ITEMS

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- Comments due by July 9, 2012 to cancomments@nerc.net using the CAN Comment Form:

  - CAN-0033: PRC-023 Transmission Relay Loadability Criteria Selection (Draft CAN)

  - CAN-0044: TOP-001 Operating Emergencies and Emergency Conditions (Draft CAN)

**Reliability Guideline: System Operator Verbal Communications Posted for Comment**

- Reliability Guideline: System Operator Verbal Communications – Current Industry Practices, a collection of industry practices compiled by the NERC Operating Committee to offer voluntary guidance for an effective system operator verbal communications program, has been posted for industry comment through August 10, 2012.

- Comments must be submitted with this comment form and emailed to reliabilityguidelinecomments@nerc.net with the words "Reliability Guideline: System Operator Verbal Communications" in the subject line. Redline document changes, PDF versions of the document, and email comments will not be accepted.

**Proposed Revisions to Rules of Procedure and Appendices Posted for Comment**

- NERC is proposing changes to its Rules of Procedure (ROP) Section 500, and Appendices 2, 5A, and 5B. NERC is soliciting comments on these proposed amendments. Redline versions of the ROP section and appendices showing the proposed additions, deletions, and revisions are now available on NERC's Rules of Procedure webpage. In addition, the posting includes a separate document that provides a detailed summary and discussion of the proposed revisions. Comments are due by July 30, 2012 and must be submitted electronically to ROPcomments@nerc.net.

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  - State of Standards Webinar, July 26, 2012, 1:00-5:00 p.m. Eastern (Register)
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You have received this email because you are a registered representative in the Registered Ballot Body.

**From:** Monica Benson
**To:** NERC Standards Announcements (Do Not Reply)
**Subject:** NERC: Standards Bulletin - July 9-15, 2012 - Correction (CANs Comment Due Date: July 27, 2012)
**Date:** Monday, July 09, 2012 11:06:27 AM

# Standards Bulletin (Correction)

## July 9-15, 2012

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## STANDARDS ITEMS

**Current Ballots (ballot periods close at 8 p.m. Eastern)**

- Project 2006-06: Reliability Coordination (COM-001-2) – Open June 27 - July 6, 2012 (Successive Ballot and Non-binding Poll) The Successive Ballot and Non-binding Poll windows will be extended one day at a time until a quorum is achieved.

**Posted for Comment (comment periods close at 8 p.m. ET)**

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- Standard Processes Manual Revisions to Implement SPIG Recommendations – Open June 20 - July 19, 2012 (Comment Form)

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**Join Ballot Pools (ballot pool windows close at 8 a.m. ET)**

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**OTHER ITEMS**

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**Upcoming Events**

- Standards Committee Meetings:
  - Standards Committee Communications and Planning Subcommittee Meeting, July 10, 2012, 1:00-5:00 p.m. MT, Denver, CO (Agenda)
  - Standards Committee Process Subcommittee Meeting, July 10, 2012, 1:00-5:00 p.m. MT, Denver, CO (Agenda)

    - Standards Committee Meeting, July 11, 2012, 8:00 a.m.-5:00 p.m. MT and July 12, 2012, 8:00 a.m.-3:00 p.m. MT, Denver, CO (Agenda)
    - Regional Standards Group Meeting, July 12, 2012, 3:00-6:00 p.m. MT, Denver, CO (Agenda)
- Industry Webinars
    - State of Standards Webinar, July 26, 2012, 1:00-5:00 p.m. Eastern (Register)
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**From:** NERC Standards Announcements (Do Not Reply)
**To:** monica.benson@nerc.net
**Subject:** NERC: Standards Bulletin - July 9-15, 2012
**Date:** Monday, July 09, 2012 9:51:54 AM

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- Draft Request for Data or Information: Order No. 762 Transmission System Performance Following Loss of a Single Bulk Electric System Element – Open June 19 - July 9, 2012 (Comment Form)

- Standard Processes Manual Revisions to Implement SPIG Recommendations – Open

June 20 - July 19, 2012 (Comment Form)

- Interpretation 2012-INT-02: Interpretation of TPL-003-0a and TPL-004-0 for SPCS – Open June 20 - July 19, 2012 (Comment Form)

- Interpretation 2012-INT-05: Interpretation of CIP-002-2 for OGE – Open June 27-July 27, 2012 (Comment Form)

- Interpretation 2010-INT-01: Interpretation of TOP-006-2 R1.2 and R3 for FMPP – Open June 14 - July 30, 2012 (Comment Form)

- Project 2012-08.1: Phase 1 of Glossary Updates: Statutory Definitions – Open June 19 - August 2, 2012 (Comment Form)

**Join Ballot Pools (ballot pool windows close at 8 a.m. ET)**

- Interpretation 2010-INT-01: Interpretation of TOP-006-2 R1.2 and R3 for FMPP – Open June 14 - July 13, 2012 (Join Ballot Pools for Initial Ballot and Non-binding Poll)

- Project 2012-08.1: Phase 1 of Glossary Updates: Statutory Definitions – Open June 19 - July 18, 2012 (Join Ballot Pool)

**Pending Ballots (ballot periods close at 8 p.m. ET)**

- Interpretation 2010-INT-01: Interpretation of TOP-006-2 R1.2 and R3 for FMPP – Open July 20-30, 2012 (Initial Ballot and Non-binding Poll)

- Project 2012-08.1: Phase 1 of Glossary Updates: Statutory Definitions – Open July 24 - August 2, 2012 (Initial Ballot)

**Background Information for Upcoming P81 Standards Project Posting**

In its March 15, 2012 order on NERC's Find, Fix, and Track process, FERC included a paragraph (paragraph 81) indicating its interest in obtaining views from NERC, the Regional Entities, and other interested parties about reliability standards or requirements within reliability standards that provide little protection for the Bulk-Power System or are redundant. A core team consisting of industry representatives led by EEI and LPPC trade associations, Regional Entities, and NERC – referred to as the P81 team – is working to establish a list of requirements to be considered for retirement.

The team has been conducting a concentrated effort to expeditiously respond to the opportunity presented in the order and is submitting a Standard Authorization Request (SAR) to address this project at this week's July 11-12 Standards Committee meeting. The SAR posting will provide more information regarding the phased structure of the project and will provide the opportunity for wider industry input on the list of potential requirements to retire in the initial phase, as well as the criteria the team used for determining whether a requirement may be eligible for removal.

As the SAR is finalized and work continues on the P81 project, NERC will continue to update stakeholders in this bulletin and elsewhere.

**Standard Drafting Team Vacancies**

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the Drafting Team Vacancies page on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

- Project 2007-02: Operating Personnel Communication: Seeking an individual from SERC or SPP with Transmission Operating Center, Reliability Coordinator, or Balancing Authority experience. Candidates should have experience developing verbal or written communication protocols for real-time operating personnel or managing real-time Bulk Electric System operations, or be a member of the Reliability Coordinator Working Group.

- Project 2007-06: System Protection Coordination: Seeking an individual from a Canadian entity with experience in coordination of Protection Systems (new installations and revisions).

- Project 2007-12: Frequency Response: Seeking individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

## OTHER ITEMS

**Compliance Application Notices (CANs) Posted for Comment**

- Comments due by July 9, 2012 to cancomments@nerc.net using the CAN Comment Form:
    - CAN-0033: PRC-023 Transmission Relay Loadability Criteria Selection (Draft CAN)
    - CAN-0044: TOP-001 Operating Emergencies and Emergency Conditions (Draft CAN)

**Reliability Guideline: System Operator Verbal Communications Posted for Comment**

- Reliability Guideline: System Operator Verbal Communications – Current Industry Practices, a collection of industry practices compiled by the NERC Operating Committee to offer voluntary guidance for an effective system operator verbal communications program, has been posted for industry comment through August 10, 2012.
- Comments must be submitted with this comment form and emailed to reliabilityguidelinecomments@nerc.net with the words "Reliability Guideline: System Operator Verbal Communications" in the subject line. Redline document changes, PDF versions of the document, and email comments will not be accepted.

**Proposed Revisions to Rules of Procedure and Appendices Posted for Comment**

- NERC is proposing changes to its Rules of Procedure (ROP) Section 500, and Appendices 2, 5A, and 5B. NERC is soliciting comments on these proposed amendments. Redline versions of the ROP section and appendices showing the proposed additions, deletions, and revisions are now available on NERC's Rules of Procedure webpage. In addition, the posting includes a separate document that provides a detailed summary and discussion of the proposed revisions. Comments are due by July 30, 2012 and must be submitted electronically to ROPcomments@nerc.net.

**Upcoming Events**

- Standards Committee Meetings:
    - Standards Committee Communications and Planning Subcommittee Meeting, July 10, 2012, 1:00-5:00 p.m. MT, Denver, CO (Agenda)
    - Standards Committee Process Subcommittee Meeting, July 10, 2012, 1:00-5:00 p.m. MT, Denver, CO (Agenda)

- Standards Committee Meeting, July 11, 2012, 8:00 a.m.-5:00 p.m. MT and July 12, 2012, 8:00 a.m.-3:00 p.m. MT, Denver, CO (Agenda)
- Regional Standards Group Meeting, July 12, 2012, 3:00-6:00 p.m. MT, Denver, CO (Agenda)

- Industry Webinars
  - State of Standards Webinar, July 26, 2012, 1:00-5:00 p.m. Eastern (Register)
  - Project 2009-01: Disturbance Sabotage and Reporting, July 30, 2012, 2:00-3:30 p.m. Eastern (Register)

- Fall Reliability Standards and Compliance Workshop, October 23-25, 2012, Westin Buckhead, Atlanta, GA

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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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

# Northeast Power Coordinating Council, Inc.

# Regional Reliability Standards Process Manual

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**Approved by NPCC Board of Directors**
**XXXX XX, 20XX**
**Approved by NERC Board Of Trustees XXXX XX, 20XX**
**Adopted by FERC XXXX XX, 20XX**

# NPCC

## REGIONAL RELIABILITY STANDARDS PROCESS MANUAL

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## I. EXECUTIVE SUMMARY

The purpose of the Northeast Power Coordinating Council, Inc. ("NPCC"), is to enhance the reliability of the international, interconnected ~~b~~Bulk ~~power~~Electric ~~s~~System in Northeastern North America through the development of more stringent and specific regional reliability standards and compliance assessment and enforcement of continent-wide and regional reliability standards pursuant to the execution and implementation of a Regional Delegation Agreement with the Electric Reliability Organization ("ERO") and applicable Canadian Memoranda of Understanding that are backstopped by the Federal Energy Regulatory Commission ("FERC") and Canadian Provincial authorities. In the development and enforcement of ~~R~~regional ~~R~~reliability ~~S~~standards, NPCC, to the extent possible, facilitates attainment of fair, effective, efficient, and competitive electric markets.

General Membership in NPCC is voluntary and is open to any person or entity, including any entity participating in the Registered Ballot Body of the ERO that has an interest in the reliable operation of the Northeastern North American Bulk Electric System.

This NPCC Regional Reliability Standards Process Manual describes the procedures, policies and practices approved by NPCC members and implemented to ensure an "open, fair, and inclusive" process for the transparent initiation, development, implementation and revision of NPCC ~~R~~regional ~~R~~reliability ~~S~~standards necessary for the reliable operation of the international and interconnected Bulk Electric System in Northeast North America. These Standards will, in all cases, not be inconsistent with or less stringent than any requirements of the North American Electric Reliability Council/Electric Reliability Organization (NERC/ERO) Reliability Standards. Each regional reliability standard shall enable or support one or more NERC/ERO reliability principles[1], thereby ensuring that each standard serves a purpose in support of the reliability of the regional Bulk Electric System. Each standard shall also be consistent with all ~~of~~ pertinent reliability principles~~–~~, thereby ensuring that no standard undermines reliability ~~-~~as an unintended consequence.

## II. REGIONAL RELIABILITY STANDARDS PROCESS

### 1. CHARACTERISTIC ATTRIBUTES

The NPCC Regional Reliability Standards Process is:

- **Open** — The NPCC Regional Reliability Standards Process provides any person or entity that is directly and materially affected by the reliability of the NPCC's Bulk Electric System~~–~~ the ability to participate in the development and approval of reliability standards. Comments ~~can~~may be submitted by any person or entity. NPCC utilizes a Website to accomplish this. Online posting and review of standards and the real time sharing of comments uploaded to the

1. Available on the NERC Website: www.nerc.com.

Website allow complete transparency. There are no undue financial barriers to participation. Participation in the open comment process is not ~~–~~restricted on the basis of technical qualifications or other such requirements.

- **Inclusive** — The NPCC Regional Reliability Standards~~-~~ Process provides any person with a direct and material interest the right to participate by expressing an opinion and its basis; have that position considered; and, in the event they are not satisfied with the response to their opinion, ~~–~~appeal the response through an established appeals process if desired.

- **Balanced** — The NPCC Regional Reliability Standards~~–~~ Process seeks to achieve a balance of interests; ~~–~~shall not be dominated by any two interest categories and no single interest category shall be able to defeat a matter. This will be accomplished through the NPCC Bylaws[2] which define six sectors (categories) for voting. All individuals and entities that are directly and materially affected by the reliability of the NPCC's ~~b~~Bulk ~~power~~Electric ~~s~~System are welcome to participate

- **Fair Due Process** — The NPCC Regional Reliability Standards ~~–~~Process provides for reasonable notice and opportunity for public comment. ~~–~~The procedure includes public notice of the intent to develop a standard; a 45 calendar day public comment period on the proposed standard request or standard; due consideration of those public comments; and responses to those comments to be posted on the NPCC Website. A final draft of the notice of intent to develop the standard or the draft standard itself (both the clean and redline versions) along with the responses to comments will be posted for a 30 calendar day pre-balloting period, after which a ballot of NPCC Members will be conducted. ~~Voting is open to NPCC members only.~~ Upon approval by the NPCC Members, the NPCC Board then votes to approve submittal of the ~~R~~regional ~~R~~reliability ~~S~~standard to NERC.

- **Transparent** — All actions material to the development of ~~R~~regional ~~R~~reliability ~~S~~standards are transparent and information regarding the progress of a standards development action is made available to the public through postings on the NPCC Website as well as~~-~~ through E-mail lists.

In as much as NPCC is one of several regional entities within the Eastern Interconnection of North America, there will be **no** *presumption of validity* by the ERO for any NPCC ~~R~~regional ~~R~~reliability ~~S~~standard. In order to receive the approval of the ERO, the NPCC Reliability Standards Development Process must also achieve the following objectives:

- **No Adverse Impact on Reliability of the Interconnection** —A NPCC ~~R~~regional ~~R~~reliability ~~S~~standard provides a level of Bulk Electric System reliability that is necessary and adequate to protect public health, safety, welfare, and North American security and will not have an adverse impact on

2. Available on the NPCC Website: www.npcc.org

the reliability of the Interconnection or other Regions within the Interconnection.

- **Justifiable Difference** — A NPCC ~~R~~regional ~~R~~reliability ~~S~~standard is based on justifiable differences between Regions, such as different electrical systems or facilities, sensitivity of load to disruptions, sensitivity of generation to disruptions, frequency and voltage sensitivity, system operating limit development and facilities ratings process, electrical system interactions, etc. Comment: Given the new 100kV BES definition, will some of these differences persist? Issues and differences will still exist. Comment to be answered. Chris de Graffenried submitted the comment.
- **Uniformity**- NPCC ~~R~~regional ~~R~~reliability ~~S~~standards shall provide for as much uniformity as possible with reliability standards across the interconnected ~~b~~Bulk ~~power~~Electric ~~s~~System of the North American continent. A NPCC ~~R~~reliability ~~S~~standard shall be ~~more~~no less ~~-~~stringent and may be more specific than a continent-wide reliability standard; may include a regional variation that addresses matters that the continent-wide reliability standard does not; or shall be justified by a regional difference necessitated by a physical difference[3] or operating difference in the northeast's Bulk Electric System.

- **No Undue Adverse Impact on Commerce** — An NPCC ~~R~~regional ~~R~~reliability ~~S~~standard will not cause any undue adverse impact on business activities that are not necessary for reliability of the Region and its interconnected Regions. All regional reliability standards shall be consistent with NERC's market principles[4].

**Other provisions of the NPCC Regional Reliability Standards Process include:**

- **Maintenance of Regional Reliability Standards-**NPCC ~~R~~regional ~~R~~reliability ~~S~~standards will be ~~-~~posted for open process review by the RSC for possible revision at least once every five (5) years after the first regulatory approval and follow the same process as in the case of a new standard. If no changes are warranted, the Regional Standards Committee (RSC) shall recommend to the NPCC Board that the standard be reaffirmed. If the review indicates a need to revise or ~~withdraw~~retire a regional standard, a Regional Standard Authorization Request shall be prepared by the RSC and submitted in accordance with the NPCC Regional Reliability Standards Process. The existing, approved standard subject to revision will remain in effect until such time as the revised version has received FERC or applicable Provincial Governmental Authorities ~~Canadian Regulatory Authority~~ approvals, as

3. The interpretation of the phrase "physical difference" will be consistent with FERC's Order, issued September 22, 2004, Granting Request For Clarification regarding Docket No. PL04-5-000, Policy Statement on Matters Related to Bulk Power System Reliability.

4. Available on the NERC Website: www.nerc.com

appropriate , at which ~~point~~time it will be retired in accordance with any applicable implementation plan associated with the newly approved regional standard. (Comment: Why can't RSC make errata changes as allowed by NERC for continent-wide reliability standards?) Want to be able to do this. Define process later in the document. This has been addressed.

- **Maintenance of the Regional Reliability Standards Process-**This NPCC Regional Reliability Standards Process will be reviewed for possible revision at least once every five (5) years, or more frequently, if needed, and subject to the same procedure as applies to ~~-~~the development of a ~~r~~Regional Reliability ~~s~~Standard. All such revisions shall be subject to approval by the NPCC Board of Directors, NERC Board of Trustees, FERC, and ~~could~~may be subject to approval, if required, by ~~a~~Applicable Governmental ~~a~~Authorities in Canada. Comment: Why can't RSC make 'errata' changes as allowed by NERC for `continent-wide reliability standards or in regional reliability standards, (see page 9)? ok This has been addressed.

- **Errata Changes to an approved Regional Standard**--From time to time, an error may be discovered in an approved Regional Standard. NPCC Staff will notify the RSC. If the RSC agrees that the correction of the error does not change the scope or intent of the associated standard, and agrees that the correction has no material impact on the end users of the standard, then the correction shall be submitted for information to the NPCC Board of Directors and provided to NERC for filing with the FERC and applicable Provincial Authorities.

- **Interpretation of Standards-** An interpretation request will be deemed valid if it is one that requests additional clarity about one or more requirements in an approved Regional Standard, but does not request approval as to how to comply with one or more 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. Any entity that is directly and materially affected by the reliability of the North American Bulk Electric Systems may request an interpretation of any requirement in any Regional Standard that has been adopted by the NERC Board of Trustees. ~~All persons who are directly and materially affected by the NPCC's Bulk Electric System reliability shall be permitted to request an interpretation of a NPCC regional reliability standard.~~ The ~~person~~entity requesting an interpretation shall send a~~-~~ written request to NPCC Standards Staff (npccstandard@npcc.org) ~~the Manager of Reliability Standards, as noted on the NPCC Website,~~ explaining the specific circumstances surrounding the request and what clarifications are required as applied to those circumstances. The request shall indicate the direct and material impact to the requesting party or others caused by the lack of clarity or a possibly incorrect interpretation of the regional standard. The NPCC Standards Staff, ~~Manager of Reliability Standards~~ along with guidance from the RSC will forward the request to the~~-~~ Task Force/Drafting Team ~~to whom responsibility was~~ originally assigned ~~for~~to ~~-~~draft~~ing~~ th~~e~~at regional reliability standard. ~~regional reliability standard.~~ If the original Task Force/Drafting Team is no longer available or assembled, then a new Task Force/Drafting

Team shall be assembled. ~~The~~The Task Force/Drafting Team will address the request for clarification as soon as practical, but not more than 45 business days following ~~rom its~~ receipt of the clarification request.~~by the Task Force.~~ This ~~written~~ interpretation upon approval by the RSC will be posted along with the affected Regional Standard ~~final approved and adopted regional standard~~ for a 45 day comment period. The Task Force/Drafting Team will respond to the comments and forward the final recommendation to the RSC. This recommendation will be ~~either a proposal for revising the standard with~~ a ~~temporary~~ clarification, and~~or~~ may include a proposal for revising a Standard.~~a clarification.~~ The clarification ~~or temporary clarification~~ upon requisite approvals, will stand until such time as the regional standard is revised through the normal RSAR process, at which time the regional standard will ~~be modified to incorporate~~address the ~~clarifications~~issues raised ~~provided~~ by the interpretation.

## 2. ELEMENTS OF A REGIONAL RELIABILITY STANDARD

- **Elements of a Regional Reliability Standard**

To ensure uniformity of regional reliability standards and avoid inconsistency with NERC continent-wide standards, a regional reliability standard shall be consistent with ~~of the~~ the elements identified in this section of the procedure. These elements are intended to apply a systematic discipline in the development and revision of regional standards. This discipline is necessary for achieving regional standards that are measurable, enforceable, and consistent as well as results oriented;[5,~~6~~] i.e.

- Performance-based,
- Risk-based, and
- Capability-based.

The Standard Drafting Team (SDT) should strive to achieve a portfolio of performance, risk, and capability-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a) **Performance-based** - defines a specific reliability objective or outcome that has a direct, observable effect on the reliability of the NPCC ~~b~~Bulk ~~power~~Electric ~~s~~System, i.e. an effect that can be measured using power system data or trends.

b) **Risk-based** - defines actions of entities that reduce a stated risk to the reliability of the NPCC ~~b~~Bulk ~~power~~Electric ~~s~~System and can be measured by evaluating a particular product or outcome resulting from the required actions.

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5. Results-based Standards see http:www.nerc.com/filez/standards/Project2010-06_Results-based_Reliability_Standards.html.

~~6. Results-based Standards presentation: http://www.nerc.com/files/Results-Based-Standards-102010.pdf .~~

c) **Capability-based** - defines capabilities needed to perform reliability functions and can be measured by demonstrating that the capability exists as required.

Each regional reliability standard shall enable or support one or more of the reliability principles as identified in the most recent set posted on the NERC website. Each reliability standard shall also be consistent with all of the reliability principles. The intent of the set of NPCC regional reliability standards is to deliver an Adequate Level of Reliability as defined by NERC.

Recognizing that Bulk Electric System reliability and electricity markets are inseparable and mutually interdependent, all regional reliability standards shall be consistent with the most recent set of Market Interface Principles as posted on the NERC website. Consideration of the Market Interface Principles is intended to ensure that regional reliability standards are written such that they achieve their reliability objective without ~~causing~~placing undue restrictions or causing adverse impacts on competitive electricity markets.

~~**Elements of a Regional Reliability Standard**~~

~~A regional reliability standard includes several components designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the bulk power system. The components of a regional reliability standard include mandatory and enforceable sections and informational sections of the standard.~~

~~Mandatory and Enforceable Sections of a Standard typically include the following:~~

~~Title: A brief, descriptive phrase identifying the topic of the standard.~~
~~Number: A unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the standards.~~
~~Purpose: The reliability outcome achieved through compliance with the requirements of the standard.~~
~~Applicability~~
~~Effective Dates: Identification of when each requirement becomes effective in each jurisdiction.~~
~~Requirement: An explicit statement that identifies the functional entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each requirement shall be a statement for which compliance is mandatory~~
~~Measure: Provides identification of the evidence or types of evidence needed to demonstrate compliance with the associated requirement. Each requirement~~

shall have at least one measure. Each measure shall clearly refer to the requirement(s) to which it applies.
Evidence Retention: Identification, for each requirement in the standard, of the entity that is responsible for retaining evidence to demonstrate compliance, and the duration for retention of that evidence.
Variance: A requirement (to be applied in the place of the continent-wide requirement), and its associated measure and compliance information, that is applicable to a specific geographic area or to a specific set of functional entities.

Informational Sections of a Standard

Application Guidelines: Guidelines to support the implementation of the associated standard.
Procedures: Procedures to support implementation of the associated standard.
Time Horizon: The time period an entity has to mitigate an instance of violating the associated requirement.4
Compliance Enforcement Authority: The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated standard.
Compliance Monitoring and Assessment Processes: Identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated standard.
Additional Compliance Information: Any other information related to assessing compliance such as the criteria or periodicity for filing specific reports.

Compliance Elements Associated with a Standard

Violation Risk Factors and Violation Severity Levels: Violation risk factors (VRFs) and violation severity levels (VSLs) are used as factors when determining the size of a penalty or sanction associated with the violation of a requirement in an approved reliability standard. Each requirement in each regional standard has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with NPCC staff, at the same time as the associated regional standard, but are not part of the regional standard. The NPCC Board of Directors is responsible for approving VRFs and VSLs.

Violation Risk Factors
VRFs identify the potential reliability significance of non-compliance with each requirement. Each requirement is assigned a VRF in accordance with the latest approved set of VRF criteria.

Violation Severity Levels
VSLs define the degree to which compliance with a requirement was not achieved. Each requirement shall have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of non-compliant performance and may have only one,

~~two, or three VSLs. Each requirement is assigned one or more VSLs in accordance with the latest approved set of VSL criteria.~~

~~The most current version of the approved NERC Reliability Standard template and its associated elements as or if applicable, will be used at the time of the development of the NPCC Regional Reliability Standard to ensure all essential elements are contained therein to achieve consistency and uniformity and meet all statutory requirements.~~

A reliability standard includes several components designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the Bulk Electric System. The components of a reliability standard include mandatory requirements, elements necessary to demonstrate compliance and monitor and assess compliance with requirements, and informational sections of the standard.

**Requirements and Elements,** in accordance with the most recent version of the NERC Standards Processes Manual, necessary to Demonstrate Compliance and Monitor and Assess Compliance with Requirements, such as:

***Title:*** A brief, descriptive phrase identifying the topic of the standard.

***Number:*** A unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the standards.

***Purpose:*** The reliability outcome achieved through compliance with the requirements of the standard.

***Effective Dates:*** Identification of when each requirement becomes effective in each jurisdiction.

***Requirement:*** An explicit statement that identifies the functional entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each requirement shall be a statement for which compliance is mandatory.

***Measure:*** Provides identification of the evidence or types of evidence needed to demonstrate compliance with the associated requirement. Each requirement shall have at least one measure. Each measure shall clearly refer to the requirement(s) to which it applies.

***Evidence Retention:*** Identification, for each requirement in the standard, of the entity that is responsible for retaining evidence to demonstrate compliance, and the duration for retention of that evidence.

***Variance:*** A requirement (to be applied in the place of the continent-wide requirement), and its associated measure and compliance information, that is applicable to a specific geographic area or to a specific set of functional entities.

***Time Horizon:*** The time period an entity has to mitigate an instance of violating the associated requirement.[4]

***Compliance Enforcement Authority:*** The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated standard.

***Compliance Monitoring and Assessment Processes:*** Identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated standard.

***Additional Compliance Information:*** Any other information related to assessing compliance such as the criteria or periodicity for filing specific reports.

***Violation Risk Factors and Violation Severity Levels:*** Violation risk factors (VRFs) and violation severity levels (VSLs) are used as factors when determining the size of a penalty or sanction associated with the violation of a requirement in an approved reliability standard[5]. Each requirement in each reliability standard has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with NERC staff, at the same time as the associated reliability standard, but are not part of the reliability standard. The Board of Trustees is responsible for approving VRFs and VSLs.

***Violation Risk Factors***

VRFs identify the potential reliability significance of noncompliance with each requirement. Each requirement is assigned a VRF in accordance with the latest approved set of VRF criteria[6].

***Violation Severity Levels***

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement shall 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. Each requirement is assigned one or more VSLs in accordance with the latest approved set of VSL criteria[7].

**Informational Sections of a Standard**

***Application Guidelines:*** Guidelines to support the implementation of the associated standard.

***Procedures:*** Procedures to support implementation of the associated standard.

## 3. KEY PARTICIPANTS, ROLES, TERMS AND FUNCTIONS

COMMENT: There is no mention of who is to perform a quality review. Need to add this to the appropriate body's role. Is it the RSC's role? Legal, technical writer, and compliance and standards staff shall comprise the quality review team.

- **NPCC Board of Directors ~~(BOD, Board)~~** - The NPCC Board Of Directors shall consider for adoption regional reliability standards, definitions, variances, interpretations and associated implementation plans that have been processed according to the processes identified in this manual. In addition, the Board shall consider for approval, VRFs and VSLs, Implementation Plans, associated with each member approved regional standard. Once the Board Of Directors adopts a regional reliability standard, definition, variance, interpretation or implementation plan, or once the Board Of Directors approves separate VRFs or VSLs, the Board of Directors shall direct NPCC staff to submit the document(s) for approval ~~by~~to the NERC Board of Trustees.

- **NPCC Members** - The ballot body is comprised of all entities or individuals that qualify for one of the stakeholder sectors within NPCC as stated in ~~-~~the most recently approved NPCC Bylaws. All General and Full Members of NPCC can participate in the balloting of regional standards. Any entity or person may submit comments during comment periods for standards including non-NPCC members.

- **Regional Standards Committee (RSC)**—A NPCC Board Of Directors appointed committee charged with management and oversight of the NPCC Regional Reliability Standards Process for development of regional standards, VRFs, VSLs, definitions, variances, interpretations, and implementation plans in accordance with this manual, under the sector based voting structure described in the NPCC Bylaws.

  RSC membership is open to NPCC members and consists of a balance of stakeholder interests that provide for or are materially impacted by the reliability of the Bulk Electric System. Its responsibilities are defined in detail in the NPCC RSC Scope posted on the NPCC Website

- –The NPCC RSC will consider requests for new or revised regional reliability standards and be available ~~for advisement~~ to advise the NPCC Board Of Directors on the regional standards, and standards related issues in general.

  The RSC may not itself modify mandatory and enforceable sections of a regional- standard except in the event of minor corrections of a standard such as errata. The RSC may make revisions to the sections of the regional standard that are not mandatory and enforceable.

  The RSC is responsible for ensuring that the regional standards, VRFs, VSLs definitions, variances, interpretations, ~~and~~ implementation plans, and any supporting documents developed by drafting teams are developed in accordance with the processes in this manual and meet NERC's and FERC's benchmarks for reliability standards including criteria for all governmental approvals.

  The RSC disposition regarding the Regional Standard Authorization Request (RSAR), which will in all cases be within sixty (60) calendar days of receipt of a completed RSAR, shall be one ~~fo~~of the following:

  - Accept the standard request as a candidate for development of a new standard, revision of an existing standard, or deletion of an existing standard. The RSC may, at its discretion, expand or narrow the scope of the standard request under consideration. The RSC shall prioritize the development of standards in relation to other proposed standards, as may be required based on the volume of requests and resources.

  - Reject the standard request. If the RSC rejects a standard request, a written explanation for rejection will be delivered to the requester within 30 calendar days of the decision.

  - Remand the standard request back to the requester for additional work. The NPCC standards staff will make reasonable efforts to assist the requester in addressing the deficiencies identified by the RSC. The requester may then resubmit the modified standard request using the

process above. The requester may choose to withdraw the standard request from further consideration prior to acceptance by the RSC.

The NPCC Standard Process responsibilities of the RSC include:

- Oversight of all Drafting Team activities. ~~The Drafting Team,~~ ~~a~~After it is assigned by the RCC, the Drafting Team shall report to the RSC.
- Review of NPCC Draft Standards (for such factors as completeness, sufficient detail, rational result, and compatibility with existing NERC and other Regional standards), and clarify standard development issues not specified in this procedure. Under no circumstance will the RSC unilaterally make any substantive changes to the ~~mandatory~~mandatory and enforceable sections of a draft standard.
- Ensure that the drafting team has given due consideration to the comments of all stakeholders ~~and minority objections,~~ in approving a proposed regional reliability standard which is to go to ballot.
- Approve posting of draft standards for pre-ballot ~~posting~~review under a sector based voting structure as described later in the NPCC Bylaws; or
- Remand the draft regional standard back to the Task Force acting as the drafting team for further work or recommend a change in those participating in the drafting team (i.e. a new drafting team).

- **NPCC Standards Staff** — The standards staff~~, led by the Assistant Vice-President of Standards,~~ is responsible for assisting the RSC in administering NPCC's Regional Reliability Standards Processes in accordance with this manual. The standards staff provides support to the RSC in managing the standards processes and in supporting the work of all regional drafting teams. The standards staff works to ensure the integrity of the standards processes and consistent quality and completeness of the regional standards, through drafting team support and conducting quality reviews. The standards staff facilitates all steps in the development of regional standards, definitions, variances, interpretations and associated implementation plans. The standards staff works with drafting teams in developing VRFs and VSLs for each regional standard.

  The standards staff is responsible for presenting members' approved regional standards, definitions, variances, interpretations and associated implementation plans to the NPCC Board Of Directors for adoption. When presenting standards-related documents to the NPCC Board Of Directors for adoption or approval, the standards staff shall report the results of the associated stakeholder ballot, including identification of unresolved stakeholder objections and an assessment of the documents' practicality and enforceability as well as any polling information obtained during standard development.

- **Reliability Coordinating Committee (RCC)** —The RCC, will support the standards development process through the assignment of NPCC Task Forces

to serve as the foundation for Drafting Team formation. The RCC may also perform a technical advisory role in the Regional Reliability Standards ~~p~~Process through comments and recommendations. Need words for RCC involvement with supplying technical justification, etc.

- **Requester**— A Requester is any individual or an entity (organization, company, government authority, including the RSC, etc.) that submits a completed request for development, revision, or withdrawal of a regional standard. Any person or an entity that is directly and materially affected by an existing standard or the need for a new standard may submit a request for a new standard or revision to a standard. The Requester is assisted by the RSAR drafting team (if one is appointed by the RSC) or NPCC standards staff to complete the drafting of the RSAR prior to it being forwarded to the RSC with a request to draft a regional standard. The Requester is responsible for the RSAR, assisted by the RSAR drafting team or NPCC standards staff, until such time the RSC authorizes development of the standard. The Requester has the option at any time to allow the RSAR drafting team to assume full responsibility for the RSAR. The Requester may choose to participate in subsequent standard drafting efforts related to the RSAR.

- **Task Forces and Working Groups,**—The committees, task forces and working groups within NPCC , serve an active role in the standards process as follows:
  - Identify the need for new or modified regional standards.
  - Initiate NPCC Standards actions by developing Regional Standard Authorization Requests (RSARs).
  - Develop comments (views and objections) to standards actions.
  - Participate in NPCC Standard drafting.
  - Provide technical oversight in response to changing industry conditions and ERO Requirements.
  - Conduct Field Tests, as required

- **NPCC Compliance Committee (CC)**
  - Provide compliance review of technical requirements.
  - Assist the Drafting Team with the development of VSLs and VRFs.
  - Participate in a standard's quality review.

- **Compliance Monitoring and Enforcement Program -** The NERC ~~c~~Compliance ~~m~~Monitoring and ~~e~~Enforcement ~~p~~Program (CMEP) may be used to manage~~s~~ and enforce~~s~~ compliance with approved regional and NERC reliability standards. The compliance program area shall provide feedback to drafting teams during the standards development process to ensure the compliance enforcement program can be practically implemented for the standards under development.

  The ~~c~~Compliance Montoring and ~~e~~Enforcement ~~p~~Program may be used to conduct field tests or data collection related to compliance elements of proposed standards and may provide assistance with field tests or data collection when requested. The compliance enforcement program shares its observations regarding the need for new

or modified requirements with the standards staff for use in identifying the need for new standards projects.

- **Quality Review Team -** The Quality Review Team will be comprised of legal and compliance representatives, a technical writer, and NPCC Standards staff. It will not involve individuals who participated in the development of the standard.

## 4. PROCEDURE DESCRIPTION

COMMENT: The procedure does not address how someone requests the withdrawal of an existing standard or part thereof.

### STEP 1 : REQUEST TO DEVELOP A NEW REGIONAL STANDARD

A Requester may request ~~-~~the development of~~-~~ a new ~~R~~regional ~~R~~reliability ~~S~~standard or revision of an existing standard by submitting a Regional Standard Authorization Request (RSAR) form ~~-~~to the NPCC Manager of Reliability Standards, who will promptly acknowledge receipt. The RSAR is a description of the new or revised regional standard in sufficient detail to clearly define its scope, purpose, and importance~~-~~, impacted parties and other relevant information. A "needs" statement will provide the justification for the development of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard. The Manager of Reliability Standards~~-~~ shall retain the RSAR form and make it available electronically on the NPCC Website.

The RSAR, as a minimum, shall contain the following information in order to be qualified for consideration. The NPCC Manager of Reliability Standards will assist the Requester to ensure all required information is submitted (on the RSAR):

1. Proposed Title and Date of New RSAR.
2. Requester's Name and Contact Information.
3. Purpose of the Regional Standard.
4. Description of Industry Need.
5. Provide a Brief Description of the Standard.
6. Identification of the Entities in the Functional Model as being responsible to adhere to the standard.
7. Necessary information to assist the drafting the team, to the extent feasible, to allow them to draft the standard.
8. Any existing known cross references to NPCC or NERC documents.
9. Technical background for the RSAR to properly address the need for the standard.

In addition a Cost Benefit Analysis (CBA) for the proposed standard will be performed in accordance with the NPCC Cost Effectiveness Analysis Procedure (CEAP) and be made available for presentation with the RSAR to the RSC.

The Manager of Reliability Standards shall forward all properly completed RSARs and cost benefit information to the RSC. The RSC shall meet at established intervals to review all pending RSARs. The frequency of this review process will depend on workload, but in no case shall a properly completed RSAR wait for RSC action more than 60 calendar days from the date of receipt. The RSC may take one of the following actions:

- Remand the RSAR back to the Manager of Reliability Standards for additional work. In this case, the -Manager of Reliability Standards may request additional information or clarification for the RSAR from the Requester.
- Accept the RSAR as a candidate for a new or revised standard. The- Manager of Reliability Standards shall, within 60 calendar days of acceptance, post notification of intent to develop a standard on the NPCC Website, notify the ERO to post the notification on its Website, and notify the requester of the acceptance.
- Reject the RSAR. In this case, the RSC will provide its determination to the Manager of Reliability Standards, who will then provide a written explanation for rejection to the Requester within 60 calendar days of the rejection decision.

**STEP 2: RSC ACCEPTS RSAR AND RCC ASSIGNS TF TO DRAFT NEW OR REVISED STANDARD**

A RSAR that is accepted by the RSC shall be submitted to the RCC who shall assign the development of the regional standard to a Task Force within 60 calendar days. The Manager of Reliability Standards shall oversee solicitation and recommendation of a list of additional candidates for appointment to the Drafting Team, and shall submit the list to the RSC. This list shall include the Requester. The RSC may select other individuals to serve in drafting the Standard. The Drafting Team shall consist of a group of people who collectively have the necessary technical expertise and work process skills to effectively and efficiently produce a quality standard. ~~t~~The Drafting Team reports to the RSC. The Drafting Team shall remain in place until such time as the NERC Board Of Trustees adopts the regional standard. Inquiries arising after a standard's development shall be directed by the RSC to the Task Force to which the drafting of the standard was assigned.

Concurrent with the formation of the Drafting Team, a technical group, or individuals may develop a first draft of the standard. This first draft ~~could~~may be posted early in the standards development process for comment to gain industry insights and input early in the standards development process. Upon approval of Drafting Team members, any draft standards that have been developed by a technical group or individuals will be forwarded to the Chair of that team for use as a starting point in development of the standard. The Drafting Team will then assume ownership of the standard's drafting and responses to comments from initial postings prior to the Drafting Team's formation.
Comment: There needs to be closure by indicating when will the role of the technical group or individuals ends and the Drafting Team takes over. There may also be a need to indicate who is to respond to comments from the initial posting--not the technical group or individuals, but the DT.

~~The Manager of Reliability Standards shall serve, coordinate or assign~~ NPCC staff will~~to~~ assist in the drafting of the standard including compliance measures, process and elements. The drafting of measures and compliance administration aspects of the standard will be coordinated with the NPCC Compliance Staff. When a drafting team begins its work, either in refining an RSAR or in developing or revising a proposed standard, the drafting team shall develop a project schedule and report its progress against that schedule to the RSC as requested, through the Manager of Reliability Standards.

Once the Drafting Team has produced a draft of the regional standard, VRFs, VSLs, variances and its associated implementation plan, NPCC standards staff shall coordinate Quality Review of the draft standard, consisting of technical writing, legal and compliance reviews prior to submission to RSC.

**Implementation Plan**

As a drafting team drafts its proposed revisions to a reliability standard, that team is also required to develop an implementation plan to identify any factors for consideration when approving the proposed effective date or dates for the associated standard or standards. As a minimum, the implementation plan shall include the following:

- The proposed effective date (the date entities shall be compliant) for the requirements.
- Identification of any new or modified definitions that are proposed for approval with the associated standard.
- Whether there are any prerequisite actions that need to be accomplished before entities are held responsible for compliance with one or more of the requirements.
- Whether approval of the proposed standard will necessitate any conforming changes to any already approved standards – and identification of those standards and requirements.
- The functional entities that will be required to comply with one or more requirements in the proposed standard.

A single implementation plan may be used for more than one standard. The implementation plan is posted along with the associated standard or standards for ballot. The Implementation Plan is posted for comment when available and prior to any ballots.

### STEP 3: SOLICIT PUBLIC COMMENTS ON DRAFT REGIONAL STANDARD

Once a draft standard has been verified by the RSC to be within the scope and purpose of the RSAR, NPCC staff ~~the manager of Reliability Standards~~ will post the draft standard for the purpose of soliciting public comments. The posting of the draft standard will be linked to the RSAR for reference by its title. In addition to the standard, an implementation plan shall be posted to provide additional details to the public and aid in their commenting and decision process. This implementation plan will be drafted and posted with draft standards upon the availability of sufficient information, data or targeted survey results to determine a realistic schedule for implementation. Comments on the draft standard will be accepted for a 45 calendar day period from the public notice of posting. Comments will be accepted on-line using the NPCC Open Process web-based application. Supporting documentation such as VSLs, VRFs, Implementation Plans and Guidance documents will be posted as they become available with the draft standard postings.

Comment: Will VSL's and VRF's, Guidance Documents, etc. also be posted at this time? If not, why not, and when? Response: A draft standard does not necessarily need to include the VRFs and VSLs. A statement should be included to answer this question.

NPCC staff~~The manager of Reliability Standards~~ will notify NERC to concurrently post the draft standard and all associated documents~~.~~ on the ERO Website for comments.

**STEP 4: OPEN PROCESS POSTING AND ANALYSIS OF THE COMMENTS**

The Manager of Reliability Standards~~-~~ will assemble the comments on the new draft standard and associated documents and distribute those comments to the ~~-~~Drafting Team. The Drafting Team shall give prompt consideration to the written views and comments of all participants. All submitted ~~-~~comments shall be addressed, and each commenter shall be advised of the disposition of their comments and the reasons therefore. The Manager of Reliability Standards shall ~~-~~publicly post all of the Drafting Team's responses to stakeholder comments on the NPCC Website.

The ~~-~~Drafting Team shall take one of the following actions:

- Submit the draft standard for RCC endorsement as it stands, along with the comments received and responses to the comments. Based on the comments received, the Drafting Team may include revisions that are not substantive. A substantive change is one that directly and materially affects the application of the standard, including, for example: changing "shall" to "should," changing "should" to "shall"; adding, deleting, or revising requirements; or adding, deleting, or revising measures for which compliance is mandatory.
- Make substantive revisions to the draft standard and reposts it for further open review and comment.
- Drafting Team may recommend~~s~~ Field Testing if necessary, to the RSC.

~~Requester or t~~The RSC ~~-~~may withdraw the request for the development of the regional standard at any time during the Regional Reliability Standards Process.

Comment: And then what happens? The RSC may want to continue with development of the standard and the Requester may want to appeal the decision not to proceed. No need to make any changes to the document, just answer the comment.

Upon receipt, the RCC submits the proposed regional standard to the RSC along with its recommendation~~-~~, Drafting Team statements and any field test results.

**STEP 5: RSC APPROVES OF THE NEW OR REVISED STANDARD FOR POSTING**

If the RSC, ~~-~~utilizing the composite sector voting structure, ~~,~~ votes to post the draft regional standard for approval, the draft standard, all comments received, and the responses to those comments shall be posted publicly by the Manager of Reliability Standards on the NPCC Website (www.npcc.org) for a 30 calendar day "pre-ballot review" to be followed by a NPCC member approval ballot. If the RSC decides more work is needed, the draft standard will be remanded back to the Drafting Team. All actions of the RCC, Drafting Teams, and the RSC will be recorded in regular minutes of the group(s) and posted on the NPCC Website. Once the notice for a ballot has been issued, no substantive modifications may be made to the proposed standard unless the revisions are posted and a new notice of the vote is issued.

The Drafting Team, in coordination with the RSC, will determine when no further postings of the standard are required.

Prior to a "pre-ballot" review of a standard, a quality review and a cost effectiveness analysis will be ~~done.~~performed and submitted to the RSC for approval.
Comment: Who will do the cost effectiveness analysis? Who does the quality review?
Response: According to the CEAP. Quality Review will be done by NERC. Should we do it? Identify at what points the QR is done.

The Drafting Team working with CC members shall develop draft VSLs and VRFs prior to the quality review.

**STEP 6: BALLOT OF STANDARD**

Upon notification of a ballot, the Members of NPCC's ballot body will cast their vote consistent with the NPCC Bylaws. This ballot shall commence no sooner than 15 calendar days and no later than 30 calendar days following the notification of ballot. All members of the NPCC are eligible to participate in the voting on proposed, standard revisions or deletions of regional standards. The ballot period will typically begin immediately following the 30 calendar day pre-ballot posting and will last at least 10 business days.

In order for a NPCC Regional Standard to be approved;

- A quorum must be established by at least 50% of the NPCC Members of at least 60% of the Voting Sectors on the roster of Members maintained by NPCC.
- A two-thirds majority of the total weighted sector votes cast must be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions, and non-responses. Weighted sector vote will be calculated as follows;
  - Affirmative votes cast in each sector will be divided by the sum of affirmative and negative votes cast, in that same sector, to determine the fractional affirmative vote for each sector. Abstentions and non-responses will not be counted for the purposes of determining the fractional affirmative vote for a sector.
  - The sum of the fractional affirmative votes from all sectors divided by the number of sectors voting will be used to determine if a two-thirds majority has been achieved. (A sector will be considered as "voting" if any member of the sector in the ballot pool casts either an affirmative or a negative vote.)
  - A standard will be approved if the sum of fractional affirmative votes from all sectors divided by the number of voting sectors is at least 2/3.

Ballots will be cast electronically and alternatives are as follows;

- Affirmative
- Affirmative with Comments
- Negative
- Negative with Comments

- Abstain Comment: Could a member vote "Abstain", yet still submit comments? To be investigated by GZ and LP. Comments should be allowed with the submission of an abstention.

The ~~-~~Manager of Reliability Standards~~-~~ shall post the final outcome of the ballot process. If the regional standard is ~~rejected~~not approved, it may be withdrawn by either the RSC or the Requester, or the standard may be remanded by the RSC back to the Drafting Team to address the balloters' comments. In the event the proposed regional standard is withdrawn all comments submitted during the process will be posted and archived for consideration when redrafting the standard ~~upon~~under review.

Put in VSL straw poll process if we elect to go with it.

Once the member ballot approves the regional standard, the ~~Manager of Reliability Standards~~Assistant Vice President-Standards shall ~~-~~recommend final Regional approval to the NPCC Board. The NPCC Board ~~O~~of Directors~~-~~ may not make substantive modifications to the standard. If the NPCC Board of Directors does not approve the standard it will be remanded back to the RSC and the Drafting Team to address their concerns.

**STEP 7: IMPLEMENTATION OF THE NPCC REGIONAL~~-~~ STANDARD**

Upon approval by the NPCC BOD~~-~~, the Manager of Reliability Standards shall submit the regional standard~~-~~ to the NERC/ERO for approval(s) and subsequent filing with FERC and applicable Canadian Governmental and/or Regulatory Authorities for adoption.

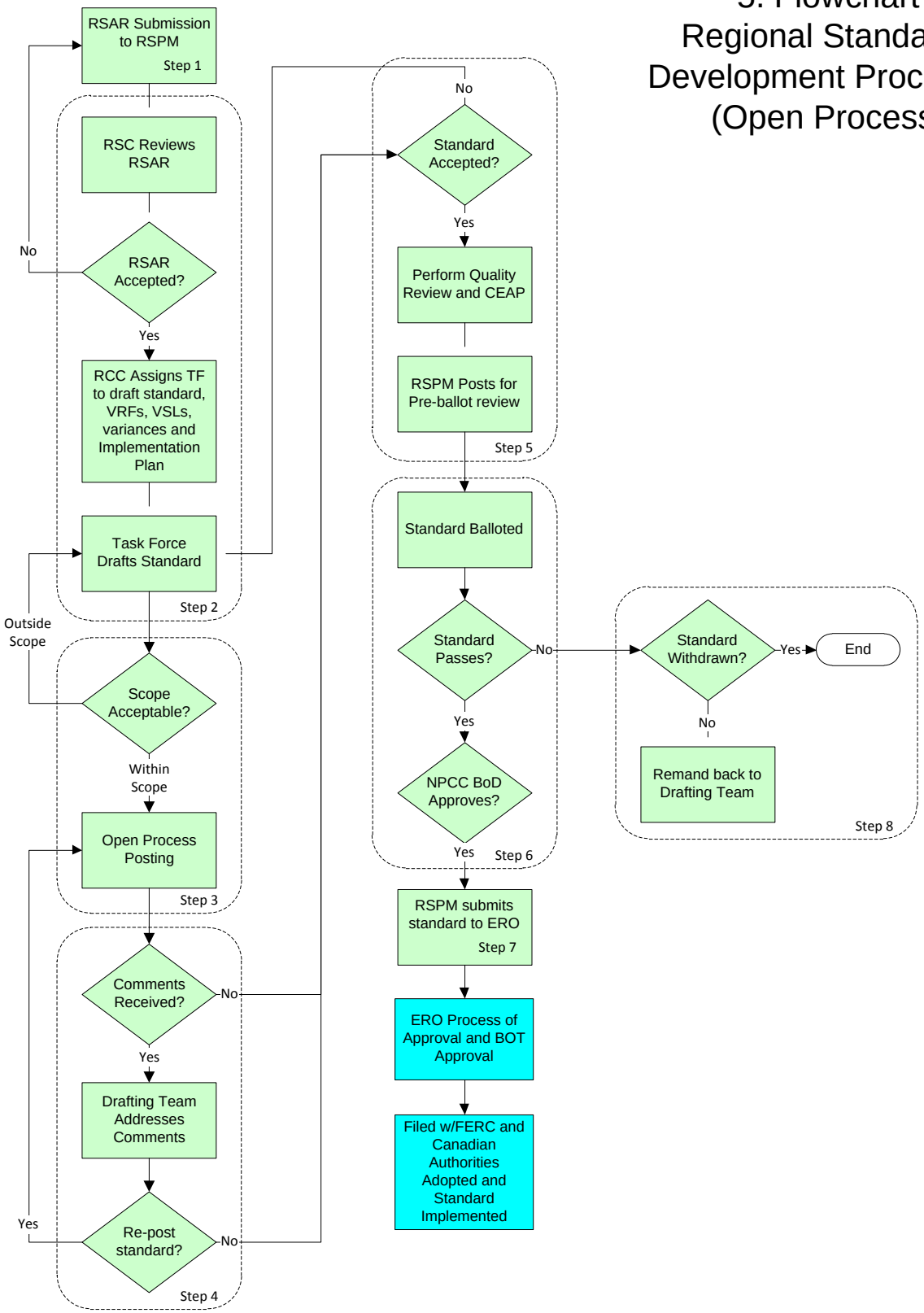
Once a reliability standard is adopted and made effective, all users, owners, planners, and operators of the Bulk Electric ~~-~~System in the NPCC geographic area of the Northeast are required to comply with the standard. The NERC/ERO Board of Trustees has established its ~~Compliance Monitoring and Enforcement Program~~CMEP,~~-~~ administered in the Northeast by NPCC~~-~~, to measure compliance with reliability standards and administer sanctions as appropriate. After adoption of a NPCC Regional Standard, the standard will be included in the NERC/ERO CMEP~~ompliance Monitoring Enforcement Program~~.

**STEP 8: WITHDRAWAL OR REMAND OF A REGIONAL STANDARD**

The RSC may elect to withdraw the proposed standard or remand it back to the Drafting Team for further work for situations such as ballot failure, cost considerations, etc. (Comment: Should this be a specific, finite list of valid reasons for remand?) Response: A list will restrict the BOD. The Assistant Vice President-Standards will inform NERC and the industry of the actions taken.

~~The following flow chart will be revised for the final draft.~~

# 5. Flowchart Regional Standards Development Procedure (Open Process)



NPCC may need to develop a new or modified standard, VRFs, VSLs, definition, variance, or implementation plan under specific time constraints (such as to meet a time constrained regulatory directive) or to meet an urgent reliability issue such that there isn't sufficient time to follow all the steps in the normal standards development process. Under those conditions, the Standards Committee shall have the authority to approve any of the following actions to expedite development:

• Shorten the 45-day formal comment period
• Shorten the 30-day period for forming the ballot pool
• Allow significant modifications following the initial ballot without the need for another formal comment period provided the modifications are highlighted before conducting any successive ballot
• Shorten any of the 10-day ballot windows

If a new or modified 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 occur28:

• If the standard is to be made permanent without additional substantive changes, then a SAR and a proposed standard shall be submitted to the 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 standard is to be substantively revised or replaced by a new standard, then a project for the new or revised 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 standard development process, including balloting by stakeholders, as soon as practical but within two years of the date the standard was approved by stakeholders using the expedited process.
• The standard shall be withdrawn through a ballot of the stakeholders within two years of the date the standard was approved by stakeholders using the expedited process.

## 6. ERO and Regulatory Process and Approvals

- **NERC/ERO Comment Period** — Concurrent with regional posting of final drafts, the final drafts will be forwarded to NERC for posting on the NERC website to ensure full industry awareness of the standard and expedite and coordinate all commenting. NERC/ERO shall publicly notice and request comment on the NPCC ~~R~~regional ~~R~~reliability ~~S~~standard and associated implementation plan, as specified by NERC- for comment on NERC's website and actively notify all adjoining Regions. –All comments will be responded to electronically by the Drafting Team through a posted response on the NPCC Website or a link on the NERC Website. NPCC shall have an opportunity to resolve any objections identified in the comments and may choose to withdraw the posting for comment; -revise the NPCC ~~R~~regional ~~R~~reliability ~~S~~standard and request another posting for comment~~;~~, or re-submit the NPCC ~~R~~regional ~~R~~reliability ~~S~~standard along with a response to any objections received, for approval by NERC.

- **NERC/ERO Approval of NPCC Regional Reliability Standards** — Proposed regional reliability standards shall be subject to approval by the NERC/ERO who shall have a process to evaluate and recommend whether a proposed non-Interconnection-wide NPCC ~~R~~regional ~~R~~reliability ~~S~~standard has been developed in accordance with all applicable procedural requirements and whether NPCC has considered and addressed stakeholder objections. NPCC BOD, having been notified of the results of the regional ballot concerning a NPCC ~~R~~regional ~~R~~reliability ~~S~~standard, shall vote to submit the ~~S~~standard to the NERC/ERO Board Of Trustees for approval as a NERC ~~R~~reliability ~~S~~standard. The NERC/ERO Board Of Trustees shall consider NPCC's request, the scope and implications of the ~~S~~standard, the recommendation for action on the ~~S~~standard, any unresolved stakeholder comments, and NPCC's consideration of comments and unresolved issues, if any, in determining whether to approve the NPCC ~~R~~regional ~~R~~reliability ~~S~~standard as a NERC ~~R~~reliability ~~S~~standard.

- **Regulatory Authority Approval** — A NPCC ~~R~~regional ~~R~~reliability ~~S~~standard that has been approved by the NERC/ERO Board Of Trustees shall be filed with FERC and applicable Canadian Governmental and/or Regulatory Authorities for approval and shall become effective and enforceable within the U.S., per Section 215 of the Federal Power Act, only when adopted by FERC in accordance with any associated implementation plan, and within individual Canadian Provinces, only when adopted by applicable Canadian Governmental and/or Regulatory Authorities in accordance with any associated implementation plan. The regional reliability standard, once adopted will be made part of the body of NERC reliability standards and shall be mandatory and enforceable on all applicable ~~b~~Bulk ~~power~~Electric ~~s~~System owners, operators, and users within the NPCC Region in accordance with any associated implementation plan, regardless of membership status.

## 7. Appeals

- Persons who have directly and materially affected interests and who have been or will be adversely affected by any substantive or procedural action or inaction related to the ~~-~~approval, revision, reaffirmation, or withdrawal of a regional reliability standard (appellant) shall have the right to appeal. This appeals process applies only to the regional reliability standards process as defined in this procedure.

  The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made within 30 calendar days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time. In all cases, the request for appeal must be made prior to the next step in the process.

  The final decisions of any appeal shall be documented in writing and made public.

The appeals process provides two levels, with the goal of expeditiously resolving the issue to the satisfaction of the participants:

- Level 1 Appeal

Level 1 is the required first step in the appeals process. The appellant submits a complaint in writing to the Regional Standards Process Manager (RSPM) that describes the substantive or procedural action or inaction associated with a reliability standard or the standards process. The appellant describes in the complaint the actual or potential adverse impact to the appellant. Assisted by any necessary staff and committee resources, the RSPM shall prepare a written response addressed to the appellant as soon as practical, but not more than 45 calendar days after receipt of the complaint. If the appellant accepts the response as a satisfactory resolution of the issue, both the complaint and response will be made a part of the public record associated with the standard and posted with the standard.

- Level 2 Appeal

If after the Level 1 Appeal the appellant remains unsatisfied with the resolution, as indicated by the appellant in writing to the RSPM~~egional Standards Process Manager~~, the RSPM shall convene a Level 2 Appeals Panel. This panel shall consist of five members total appointed by the NPCC's Board of Directors.

In all cases, Level 2 Appeals Panel members shall have no direct affiliation with the participants in the appeal.

The RSPM shall post the complaint and other relevant materials and provide at least 30 calendar days notice of the meeting of the Level 2 Appeals Panel. In addition to the appellant, any person that is directly and materially affected by the substantive or procedural action or inaction referenced in the complaint shall be heard by the panel. The panel shall not consider any expansion of the scope of the appeal that was not presented in the Level 1 Appeal. The panel may in its decision find for the appellant and remand the issue to the RSC with a statement of the issues and facts in regard to which unfair and/or inequitable action was ~~not~~ taken, or which fair and/or equitable action was not taken. The panel may find for or against the appellant with a specific statement of the facts that demonstrate fair and equitable treatment of the appellant and the appellant's objections. The panel may not, however, revise, approve, disapprove, or adopt a reliability standard. The actions of the Level 2 Appeals Panel shall be publicly posted.

In addition to the foregoing, a procedural objection that has not been resolved may be submitted to the NPCC Board of Directors for consideration at the time the Board decides whether to adopt a particular reliability standard. The objection must be in writing, signed by an officer of the objecting entity, and contain a concise statement of the relief requested and a clear demonstration of the facts that justify that relief. The objection must be filed no later than 30 calendar days after the announcement of the vote on the standard in question.

**Revision History**

| Version | NPCC Board Of Directors Approval | NERC Board Of Trustees Approval | FERC Approval |
|---|---|---|---|
| Original | 9/19/07 | 10/23/07 | 3/21/08 |
| Rev 1 | | | |

May 4, 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. RR12-___-000**

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this petition in accordance with Section 215(d) (1) of the Federal Power Act ("FPA") and Part 39.5 of the Federal Energy Regulatory Commission's ("FERC") regulations seeking approval of proposed Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding, associated Violation Risk Factors ("VRF") and Violations Severity Levels ("VSL"), and an implementation plan for PRC-006-NPCC-1. Upon approval, this standard will only be effective within the Northeast Power Coordinating Council ("NPCC") footprint.

The purpose of PRC-006-NPCC-1 is to provide a Regional Reliability Standard that ensures the development of an effective automatic underfrequency load shedding ("UFLS") program in order to preserve the security and integrity of the bulk power system during declining system frequency events, in coordination with the NERC UFLS reliability standard characteristics, PRC-006-1.

The proposed Regional Reliability Standard was approved by the NERC Board of Trustees during its February 9, 2012 meeting. NERC is proposing dual effective dates for the standard. NERC proposes that for the Eastern Interconnection and Québec Interconnection portions of NPCC excluding the Independent Electricity System Operator ("IESO") Planning Coordinator area of NPCC in Ontario, Canada:

> The effective date for Requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than January 1, 2016. The effective date for Requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

For the Commission's information, NERC is proposing the following for the IESO Planning Coordinator's area of NPCC in Ontario, Canada:

> All requirements are effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

This petition consists of the following:

- this transmittal letter;
- a table of contents for the entire petition;
- a narrative description explaining how the proposed Regional Reliability Standard meets FERC's requirements;
- Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding and implementation plan, submitted for approval (**Exhibit A**);
- the complete development record of the proposed Regional Reliability Standard (**Exhibit B**);
- the standard drafting team roster (**Exhibit C**); and
- the Violation Severity Level and Violation Risk Factor Guideline Analysis (**Exhibit D**).

Please contact the undersigned if you have any questions.

Respectfully submitted,

*/s/ Andrew M. Dressel*
Andrew M. Dressel
*Attorney for North American Electric Reliability Corporation*

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | |
|---|---|
| **NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION** | **) Docket No. RR12-__-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


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May 4, 2012

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## I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] hereby requests the Federal Energy Regulatory Commission ("FERC") to approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[2] and Section 39.5 of FERC's regulations, 18 C.F.R. § 39.5, proposed Regional Reliability Standard, PRC-006-NPCC-1 included in Exhibit A.

The purpose of PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding is to provide a Regional Reliability Standard that ensures the development of an effective automatic underfrequency load shedding ("UFLS") program in order to preserve the security and integrity of the bulk power system during declining system frequency events, in coordination with the NERC UFLS Reliability Standard characteristics. UFLS requirements have been in place at a continent-wide level and within Northeast Power Coordinating Council, Inc. ("NPCC") for many years prior to implementation of federally-mandated reliability standards in 2007.

NERC and NPCC believe that a region-wide and fully coordinated single set of UFLS requirements is of benefit to achieving an effective and efficient UFLS program, and their experience has supported that belief. Regional UFLS programs serve "as a last resort to preserve the Bulk-Power System during a major system failure that could cause system frequency to collapse."[3] The NPCC standard adds specificity not contained in the NERC standard for development and implementation of a UFLS program in the NPCC

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[1] NERC has been certified by FERC as the Electric Reliability Organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. 116 FERC ¶ 61,062 (2006) ("ERO Certification Order).

[2] 16 U.S.C. 824o.

[3] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1476, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

region that effectively arrests declining frequency, assists recovery following underfrequency events, and provides last resort system preservation measures.

This petition is the first request by NERC for FERC approval of this proposed Regional Reliability Standard. The Regional Reliability Standard proposed will be in effect only for applicable registered entities within the NPCC. NERC continent-wide Reliability Standards do not presently address all of the issues covered in this proposed Regional Reliability Standard.

NERC specifically requests approval of:

- Regional Reliability Standard PRC-006-NPCC-1;
- Associated Violations Risk Factors ("VRF") and Violation Severity Levels ("VSL"); and
- Implementation Plan for PRC-006-NPCC-1.

On February 9, 2012 the NERC Board of Trustees approved PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding. NERC requests that FERC approve this Regional Reliability Standard and make it effective upon FERC approval for the section of the NPCC region that lies within the United States, consistent with the proposed implementation plan. **Exhibit A** to this filing sets forth the proposed Regional Reliability Standard and implementation plan. **Exhibit B** contains the complete Development Record for the proposed Regional Reliability Standard. **Exhibit C** includes the standard drafting team roster. **Exhibit D** is the Violation Severity Level ("VSL") and Violation Risk Factor ("VRF") guideline analysis.

NERC is also filing the proposed PRC-006-NPCC-1 Regional Reliability Standard and associated documents with the applicable governmental authorities in Canada.

## II. NOTICES AND COMMUNICATIONS

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


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## III. BACKGROUND

### a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[4] Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the nation's bulk power system and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to FERC approval. Section 215 of the FPA states that all users, owners and operators of the bulk power system in the United States will be subject to FERC-approved Reliability Standards.

### b. Basis for Approval of Proposed Regional Reliability Standard

Section 39.5(a) of FERC's regulations requires the ERO to file with FERC for its approval each Reliability Standard that the ERO proposes to become mandatory and enforceable in the United States and each modification to a Reliability Standard that the ERO proposes to be made effective. FERC has the regulatory responsibility to approve standards that protect the reliability of the bulk power system. In discharging its responsibility to review, approve, and enforce mandatory Reliability Standards, FERC is authorized to approve those proposed Reliability Standards that meet the criteria detailed by Congress:

> FERC may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[5]

When evaluating proposed Reliability Standards, FERC is expected to give "due weight" to the technical expertise of the ERO and to the technical expertise of a Regional Entity organized on an Interconnection-wide basis with respect to a Reliability Standard

[4] 16 U.S.C. § 824o.
[5] 16 U.S.C. § 824o(d)(2).

to be applicable within that Interconnection. Order No. 672 provides guidance on the factors FERC will consider when determining whether proposed Reliability Standards meet the statutory criteria.[6]

A Regional Reliability Standard proposed by a Regional Entity must meet the same standards that NERC's Reliability Standards must meet, *i.e.*, the Regional Reliability Standard must be shown to be just, reasonable, not unduly discriminatory or preferential, and in the public interest.[7] FERC's Order No. 672 also requires additional criteria that a Regional Reliability Standard must satisfy: a regional difference from a continent-wide Reliability Standard must either be (1) more stringent than the continent-wide Reliability Standard (which includes a regional standard that addresses matters that the continent-wide Reliability Standard does not), or (2) a Regional Reliability Standard that is necessitated by a physical difference in the Bulk Power System.[8]

NPCC is not an "interconnection-wide" Regional Entity and its standards are intended to apply only to that part of the Eastern Interconnection within the NPCC geographical footprint and Québec. As discussed in the *Northeast Power Coordinating Council, Inc. Regional Reliability Standard Development Procedure,*[9] NPCC's standards are developed according to the following characteristic attributes:

- **Open** — The NPCC Regional Reliability Standards Development Procedure provides any person the ability to participate in the development of a standard. Any entity that is directly and materially affected by the reliability of the NPCC's Bulk Power System has the ability to participate in the

[6] *See Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards, FERC Stats. & Regs.*, ¶ 31,204 at PP 320-338 ("Order No. 672"), *order on reh'g*, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672-A").

[7] Section 215(d)(2) of the FPA and 18 C.F.R. §39.5(a).

[8] Order No. 672 at P 291.

[9] The *Northeast Power Coordinating Council, Inc. Regional Reliability Standard Development Procedure* is available at http://www.npcc.org/regStandards/Overview.aspx

development and approval of reliability standards. There are no undue financial barriers to participation. Participation in the open comment process is not conditional upon membership in the ERO, NPCC or any organization, and participation is not unreasonably restricted on the basis of technical qualifications or other such requirements. NPCC utilizes a website to accomplish this. Online posting and review of standards and the real time sharing of comments uploaded to the website allow complete transparency.

- **Inclusive** — The NPCC Regional Reliability Standards Development Procedure provides any person with a direct and material interest the right to participate by expressing an opinion and its basis, have that position considered, and appealed through an established appeals process if adversely affected.

- **Balanced** — The NPCC Regional Reliability Standards Development Procedure has a balance of interests and all those entities that are directly and materially affected by the reliability of the NPCC's Bulk Power System are welcome to participate and shall not be dominated by any two interest categories and no single interest category shall be able to defeat a matter. This will be accomplished through the NPCC Bylaws defining eight sectors (categories) for voting.

- **Fair Due Process** — The NPCC Regional Reliability Standards Development Procedure provides for reasonable notice and opportunity for public comment. The procedure includes public notice of the intent to develop a standard, a 45 calendar day public comment period on the proposed standard request, or standard with due consideration of those public comments, and responses to those comments will be posted on the NPCC website. A final draft will be posted for a 30 calendar day pre-balloting period, and then a ballot of NPCC Members will be conducted. Upon approval by the NPCC Members, the NPCC Board then votes to approve submittal of the Regional Standard to NERC.

- **Transparent** — All actions material to the development of Regional Reliability Standards are transparent and information regarding the progress is posted on the NPCC website as well as through extensive email lists.

Proposed NPCC standards are subject to approval by NERC, as the ERO, and FERC before becoming mandatory and enforceable under Section 215 of the FPA.[10] As shown above, the NPCC Regional Reliability Standard was developed in an open, transparent, and inclusive fashion. During development of the standard, workshops were conducted jointly with other Regional Entities and NPCC members. The proposed standard is

[10] 16 U.S.C. 824o.

widely supported by the NPCC ballot body and regulatory agencies that see this as a meaningful and necessary step forward in solving a longstanding problem. The standard was reviewed by NPCC legal counsel for consistency with the provisions and stated goals of the Federal Power Act and Chapter 39 of FERC's regulations.[11] As a condition of NPCC membership, all NPCC Members[12] agree to adhere to the NERC Reliability Standards in addition to the NPCC Regional Reliability Standards. NERC Reliability Standards and the NPCC Regional Reliability Standards are both enforced through the NPCC Compliance Program.

The NPCC drafting team worked closely with its technical committee on UFLS, the SS-38 Working Group on Inter-Area Dynamics Analysis, as it considered the technical issues and justifications surrounding the standard.

Additionally, NPCC conducted a number of regional workshops aimed at informing NPCC Members on the status and background of the standard's development. The draft of the standard was posted for a 45 day comment period three times during its development and the drafting team responded to all comments and technical concerns that were raised.

NERC conducted two quality reviews of the standard during which formatting and content issues were corrected. NERC also posted the draft for public consideration on two occasions after which the drafting team responded to all comments received.

As previously noted, NPCC is a Regional Entity not organized on an Interconnection-wide basis. Therefore, NERC is not required to rebuttably presume the

[11] 18 C.F.R. §39 (2011).
[12] As defined in Section IV.B of the NPCC Corporation By-laws. Available at: http://www.npcc.org/documents/aboutus/BusPlanBylaws.aspx.

proposed standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.

## IV. JUSTIFICATION FOR APPROVAL OF PROPOSED REGIONAL RELIABILITY STANDARD

This section summarizes the development of the proposed Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding; describes the reliability objectives to be achieved by the Regional Reliability Standard; explains the development history of the Regional Reliability Standard; and demonstrates how the standard meets the Commission's criteria for approval. NERC, in its analysis and approval of the proposed Regional Reliability Standard, determined that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

The complete development record for the proposed Regional Reliability Standard is provided in **Exhibit C** and includes the development and approval process, comments received during the industry-wide comment period, responses to those comments, ballot information, and NERC's evaluation of the proposed standard.

### a. Basis and Purpose of Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding

The proposed Regional Reliability standard, PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding, will provide regional requirements for Automatic Underfrequency Load Shedding to applicable entities in NPCC. UFLS requirements have been in place at a continent-wide level and within NPCC for many years prior to the implementation of federally mandated reliability standards in 2007. NPCC and its members believe that a region-wide, fully coordinated single set of UFLS requirements is

necessary to create an effective and efficient UFLS program, and their experience has supported that belief.

The proposed standard contains 23 requirements that establish UFLS obligations for entities within the NPCC region. The proposed standard is included in **Exhibit A** to this filing.

### b. Order No. 672 Criteria

In Order No. 672, the Commission identified the criteria it will use to analyze Reliability Standards proposed for approval to ensure such standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standards have met or exceeded the criteria.

#### 1. Proposed Reliability Standards must be designed to achieve a specified reliability goal

> Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

The proposed Regional Reliability Standard, PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding, was developed to provide a Regional Reliability Standard that ensures 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 PRC-006-1 Reliability Standard's requirements.

**2. Proposed Reliability Standards must be applicable to users, owners, and operators of the bulk power system, and not others.**

> Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

The proposed Regional Reliability Standard is only applicable to Generator Owners, Planning Coordinators, Distribution Providers, and Transmission Owners within the NPCC region. These entities are users, owners, or operators of the bulk power system.

**3. Proposed Reliability Standards must consider any other relevant factors.**

> Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

All comments and concerns were addressed using the *Northeast Power Coordinating Council Standards Development Procedure* which is consensus-based, technically sound, and open to the public and bordering entities that may be impacted by a Regional Reliability Standard. No other factors were identified as necessary for consideration by the standard drafting team in the development of the proposed Regional Reliability Standard.

**4. Proposed Reliability Standards must contain a technically sound method to achieve the goal.**

> Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO

> approval of a proposed Reliability Standard should be fair and open to all interested persons.

The proposed Regional Reliability Standard contains a technically sound means to achieve this goal. The PRC-006-NPCC-1 drafting team was comprised of power system engineers with experience in power system protection system design, power system operations, transmission, and generation. The proposed Regional Reliability Standard used as its basis the program characteristics defined within NPCC Directory #12 Underfrequency Load Shedding Program Requirements,[13] which contains the criteria that govern the NPCC Automatic UFLS program as designed by the NPCC Working Group on Inter-Area Dynamic Analysis (SS-38) and was approved by NPCC's highest level technical committee, the Reliability Coordinating Committee (RCC).

The proposed Regional Reliability Standard PRC-006-NPCC-1 was posted for industry technical comment three times and responses to these comments were evaluated and incorporated by the drafting team into the standard as appropriate.

**5. Proposed Reliability Standards must be clear and unambiguous as to what is required and who is required to comply.**

> Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

The proposed Regional Reliability Standard establishes clear and unambiguous requirements for Generator Owners, Planning Coordinators, Distribution Providers, and Transmission Owners within the NPCC region as detailed below.

[13] NPCC Regional Reliability Reference Directory # 12 Underfrequency Load Shedding Program Requirements (2009) ("NPCC Directory # 12"). Available at http://www.theimo.com/imoweb/pubs/ircp/NPCC/Directory_12.pdf.

Requirement R1 requires each Planning Coordinator within the NPCC region to establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding as required by the islanding criteria requirements of the NERC continent-wide Standard PRC-006-1.

Requirement R2 requires each Planning Coordinator to identify to NPCC the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics within 30 days of completion of its system studies required by the NERC continent-wide Standard PRC-006-1.

Requirement R3 requires each Planning Coordinator to provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1.

Requirement R4 requires each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC to implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in PRC-006-NPCC-1 Attachment C, Tables 1 through 3, or to collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in PRC-006-NPCC-1 Attachment C, Tables 1 through 3.

Requirement R5 requires each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 to:

5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in PRC-006-NPCC-1 Attachment C, Table 1 if applicable and

5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of PRC-006-NPCC-1 Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.

5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of PRC-006-NPCC-1 Attachment C, Table 2 or Table 3, and in the case of PRC-006-NPCC-1 Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.4 Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with PRC-006-NPCC-1 Attachment C Table 2 or PRC-006-NPCC-1 Attachment C Table 3.

Requirement R6 requires each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC to implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in PRC-006-NPCC-1 Attachment C, Table 4 or to collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in PRC-006-NPCC-1 Attachment C, Table 4.

Requirement R7 requires each Distribution Provider and Transmission Owner to set each underfrequency relay that is part of its region's UFLS program with a minimum time delay of 100 ms in the Eastern Interconnection and 200 ms in the Quebec Interconnection.

Requirement R8 requires each Planning Coordinator to develop and review once per calendar year settings for the inhibit thresholds to be utilized within its region's UFLS program.

Requirement R9 requires each Planning Coordinator to provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the

applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds.

Requirement R10 requires each Distribution Provider and Transmission Owner to implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9.

Requirement R11 requires each Distribution Provider and Transmission Owner to develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R9.

Requirement R12 requires each Transmission Owner and Distribution Provider to annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays.

Requirement R13 requires each Generator Owner to set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in PRC-006-NPCC-1 Figure 1, except as otherwise exempted in Requirements R16 and R19.

Requirement R14 requires each Generator Owner to transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator’s request.

Requirement R15 requires each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% to:

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in PRC-006-NPCC-1 Figure 1.

15.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in PRC-006-NPCC-1 Figure 1.

Requirement R16 requires each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in PRC-006-NPCC-1 Figure 1 to:

16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

Requirement R17 requires each Planning Coordinator in Ontario, Quebec, and the Maritime provinces to apply the criteria described in PRC-006-NPCC-1 Attachment A to determine the compensatory load shedding that is required in Requirement R16 part 16.3 for generating units in its respective NPCC area.

Requirement R18 requires each Generator Owner, Distribution Provider, or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO to apply the criteria described in PRC-006-NPCC-1 Attachment B to determine the compensatory load shedding that is required in Requirement R16 part 16.3 for generating units in its respective NPCC area.

Requirement R19 requires each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in PRC-006-NPCC-1 Figure 1, based on their licensing design basis, to:

19.1 Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.

19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 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.

Requirement R20 requires each Planning Coordinator to update its UFLS program database as specified by the NERC UFLS Reliability Standard on UFLS (currently PRC-006-1). This database shall include the following information:

20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.

20.2 The buses at which the Load is modeled in the NPCC library power flow case.

20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in PRC-006-NPCC-1 Figure 1, including the frequency trip threshold and time delay for each protection system.

20.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.

20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

Requirement R21 requires each Planning Coordinator to notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS, which is currently PRC-006-1.

Requirement R22 requires each Distribution Provider, Transmission Owner and Generator Owner to implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21.

Requirement R23 requires each Distribution Provider, Transmission Owner and Generator Owner to develop and submit an implementation plan within 90 days of the

request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21.

**6. Proposed Reliability Standards must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation**

> Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

The proposed Regional Reliability Standard includes a Violation Risk Factor ("VRF") and at least one Violation Severity Level ("VSL") for each requirement. The ranges of penalties for violations will be based on the applicable VRF and VSL and will be administered based on the sanctions table and supporting penalty determination process described in the FERC-approved NERC Sanction Guidelines.[14]

NPCC developed the VSLs and VRFs proposed for assignment to PRC-006-NPCC-1 following applicable NERC and FERC guidance. **Exhibit E** to this filing contains the VSL and VRF guideline analysis for PRC-006-NPCC-1.

**7. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.**

> Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

Each requirement of PRC-006-NPCC-1 has an associated measure of compliance that will assist those enforcing the standard in enforcing it in a consistent and non-preferential manner. The proposed measures are as follows:

[14] NERC Rules of Procedure Appendix 4B. Available at: http://www.nerc.com/page.php?cid=1|8|169.

**M1.** Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

**M2.** Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

**M3.** Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

**M4.** Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (PRC-006-NPCC-1 Attachment C Tables 1-3).

**M5.** Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

**M6.** Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (PRC-006-NPCC-1 Attachment C Table 4).

**M7.** Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.

**M8.** Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

**M9.** Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

**M10.** Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.

**M11.** Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.

**M12.** Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.

**M13.** Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.

**M14.** Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.

**M15.** Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.

**M16.** Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.

**M17.** Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in PRC-006-NPCC-1 Attachment A and meets Requirement R17.

**M18.** Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in PRC-006-NPCC-1 Attachment B and meets Requirement R18.

**M19.** Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in PRC-006-NPCC-1 Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

**M20.** Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

**M21.** Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

**M22.** Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

**M23.** Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement R23.

**8. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost.**

> Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently

Regional Reliability Standard PRC-006-NPCC-1 achieves its reliability goal effectively and efficiently. The standard accomplishes the reliability goal of ensuring the development of an effective UFLS program in the NPCC region that preserves the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS Reliability Standard characteristics, which is currently contained in PRC-006-1.

The implementation plan for PRC-006- NPCC-1 (included in **Exhibit A**) specifies a six year implementation schedule and provides for annual improvement over that period in the system performance expected following UFLS operation for an island condition. Modifications to the program in the first two years are limited to relay setting changes only. Modifications requiring capital improvements are scheduled to begin in the third year of the program to provide sufficient time for including expenditures in capital budgets and procuring equipment.

**9. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect bulk power system reliability.**

> Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although [FERC] will give due weight to the technical expertise of the ERO, [FERC] will not hesitate to remand a proposed Reliability Standard if [FERC is] convinced it is not adequate to protect reliability.

This proposed Regional Reliability Standard does not reflect a "lowest common denominator" approach. PRC-006-NPCC-1 incorporates the UFLS program recommendations set forth by the SS-38 Working Group on Inter-Area Dynamic Analysis in assessment studies that were performed after the 2003 Blackout. Contrary to a "lowest common denominator" approach, the Standard attempts to provide a bridge between the recommendations of the SS-38 Working Group and the current Registry Criteria by requiring the Planning Coordinator to identify those generators deemed critical to the performance of the UFLS program in order for the Regional Entity to review the status of such units.

**10. Proposed Reliability Standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability.**

> Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

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 the program characteristics.

**11. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one area or approach.**

> Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

The proposed Regional Reliability Standard is designed on a regional basis and will only apply to the NPCC region. It is not intended to be applied throughout North America.

**12. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid.**

> Order No. 672 at P 332. As directed by section 215 of the FPA, [FERC] itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

This proposed Regional Reliability Standard will not cause undue negative effects on competition or restriction of the grid. Because this standard will be applied equally across the NPCC region, PRC-006-NPCC-1 will not negatively affect competition, or restrict available transmission capability within the NPCC footprint.

**13. The implementation time for the proposed Reliability Standards must be reasonable.**

> Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, [FERC] will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

The implementation plan for the Regional Reliability Standard proposes a phased in implementation schedule as follows:

For the Eastern Interconnection and Québec Interconnection Portions of NPCC excluding the Independent Electricity System Operator ("IESO") Planning Coordinator Area of NPCC in Ontario, Canada:[15]

> The effective date for requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no

[15] Information regarding the implementation plan for the IESO and Québec Interconnection are for the Commission's information only.

earlier than Jan 1, 2016. The effective date for requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

For the IESO Planning Coordinator's Area of NPCC in Ontario, Canada:

All requirements are effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

The information submitted by NPCC supports the implementation schedule presented.

**14. The Reliability Standard development process must be open and fair.**

> Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its [FERC]-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, 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 [FERC].

NPCC develops Regional Reliability Standards in accordance with **Exhibit C** (*Regional Reliability Standards Development Procedure*) of its Regional Delegation Agreement with NERC. The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NPCC considers the comments of all stakeholders and an affirmative vote of the stakeholders and the NPCC Board of Directors are both required to approve a Regional Reliability Standard for submission to NERC and FERC.

The proposed Regional Reliability Standard has been developed and approved by industry stakeholders using NPCC's *Regional Reliability Standards Development Procedure* and was approved by the NPCC Board of Directors on November 20, 2011. The standard was subsequently presented to and approved by the NERC Board of Trustees February 9, 2012. Therefore, NPCC has utilized its standard development process in good faith and in a manner that is open and fair. No commenters disagreed with the open and fair implementation of the NPCC process.

**15. Proposed Reliability Standards must balance with other vital public interests.**

> Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

Neither NERC nor NPCC believes there are competing public interests with the request for approval of this proposed Regional Reliability Standard. No comments were received that indicated the proposed standard conflicts with other vital public interests. Therefore it is not necessary to balance this Regional Reliability Standard against any other competing public interests.

**16. Proposed Reliability Standard must not conflict with prior FERC Rules or Orders.**

> Order No. 672 at P 444. A potential conflict between a Reliability Standard under development and a Transmission Organization function, rule, order, tariff, rate schedule, or agreement accepted, approved, or ordered by the Commission should be identified and addressed during the ERO's Reliability Standard Development Process.

The proposed PRC-006-NPCC-1 Regional Reliability Standard does not conflict with any other prior FERC rules or orders and adequately addresses the directives identified in FERC Order No. 693.[16]

NERC has therefore determined that the proposed standard meets the criteria for consideration and approval as a Reliability Standard.

**c. Additional Order No. 672 Criteria for Regional Reliability Standards**

FERC's Order No. 672 also establishes additional criteria that a Regional Reliability Standard must satisfy: "A regional difference from a continent-wide Reliability Standard must either be (1) more stringent than the continent-wide Reliability Standard including a regional difference that addresses matters the continent-wide Reliability Standard does not, or (2) a Regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System."[17] The proposed standard satisfies these additional criteria.

The existing NERC continent-wide standard, PRC-006-1 – Automatic Underfrequency Load Shedding applies only to Planning Coordinators, Transmission Owners, and Distribution Providers. The proposed standard, PRC-006-NPCC-1, includes Generator Owners as applicable entities. The NPCC standard adds specificity not contained in the NERC standard for development and implementation of a UFLS program in the NPCC region that effectively arrests declining frequency, assists recovery following underfrequency events, and provides last resort system preservation measures. PRC-006-NPCC-1 achieves a coordinated, comprehensive UFLS region-wide consistent

[16] Order No. 693 at P 1480.
[17] Order No. 672 at P 291.

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 UFLS standard. It is designed to work in conjunction with, and augment the NERC standard by mitigating the consequences of an underfrequency event, 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 standard also facilitates uniformity, compliance, and clearly delineates what the applicable entities' requirements are within the region to achieve a robust, reliable and effective UFLS program. Thus, the proposed standard satisfies the additional Order No. 672 criteria for Regional Reliability Standards.

## V. SUMMARY OF THE REGIONAL RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

**NERC Evaluation:** On November 21, 2011, NPCC submitted the proposed Regional Reliability Standard for evaluation and approval to NERC in accordance with NERC's *Rules of Procedure* and *Regional Reliability Standards Evaluation Procedure*[18] that was approved by NERC's Regional Reliability Standards Working Group. NERC provided its evaluation of the proposed PRC-006-NPCC-1 standard to NPCC on December 23, 2011, included in **Exhibit B**, after NERC concluded its 45-day posting of the standard.

**Key Issues:**

The NPCC drafting team for PRC-006-NPCC-1 considered and resolved a number of issues concerning the regional UFLS program and incorporated those outcomes into the requirements of this standard. The drafting team sought the

[18] Regional Reliability Standards Evaluation Procedure, Version 1 (2009). Available at: http://www.nerc.com/docs/sac/rrswg/NERC_Regional_Reliability_Evaluation_Procedure.pdf.

recommendations of the NPCC SS-38 Working Group in order to ensure that its solutions to the issues brought forth by commenters and drafting team members were consistent with maintaining a regional effective program for all of the scenarios considered.

Among the issues resolved were: 1) generator coordination and the administration of compensatory load shedding for non-conforming generators, 2) participation of small entities in the regional UFLS program, 3) program tolerances 4) inhibit settings, 5) generator applicability, and 6) NERC PRC-006-1 coordination.

1) Generator Coordination and Compensatory Load Shedding:

The drafting team established a requirement for all new generators to conform to the generator tripping curve in the standard, thereby eliminating the problem of non-conforming generators in the future. Existing units that are already interconnected and in commercial operations that do not conform to the generator tripping curve in the standard currently obtain compensatory load shedding in accordance with existing NPCC procedures currently in effect and contained within NPCC Directory#12 Underfrequency Load Shedding Program Requirements.[19] These procedures are appended to the standard as attachments and provide the instructions for a non-conforming generator to obtain compensatory load shedding.

The drafting team also considered the existing nuclear units within NPCC with under-frequency threshold settings above the generator tripping curve. A requirement was developed that instructs these units to set the frequency trip setting upper tolerance as low as possible in accordance with the plant design and licensing limitations and to transmit the settings and any changes to settings to the Planning Coordinator.

[19] NPCC Directory # 12, *supra* note 12.

2) Small Entity Participation:

The NPCC UFLS program characteristics as developed by the NPCC SS-38 Working Group and implemented by NPCC area Planning Coordinators is designed with five discrete stages of load shedding (including an anti-stall stage) with approximately 7% of load shedding at each of the program stages. However, many smaller entities (typically those with less than 100MW) are constrained by facility design but with the technical support of the NPCC SS-38 group the drafting team developed modified program stages and tolerances for these smaller entities. The NPCC SS-38 Working Group modeled these small entity parameters to ensure that the overall regional program converged using these attributes. Furthermore, these small entity characteristics have already been incorporated within the regional UFLS criteria and included in NPCC Directory#12 Underfrequency Load Shedding Program Requirements.[20]

3) Program Tolerances:

The drafting team with the support of the NPCC SS-38 Working Group examined the tolerances that could be permitted when implementing the individual program stages of load shedding in 7% blocks. NPCC SS-38 recommended that the upper and lower program tolerances at each stage should be bounded by +/- 0.5% surrounding a nominal amount of load shed at each stage (7%). This recommendation was incorporated into the standard and provides entities designing their UFLS programs with some degree of flexibility when assigning the amount of load to be shed on declining frequency.

4) Inhibit Settings:

The drafting team recognized during the development of the standard that various inhibit thresholds designed to prevent the misoperation of UFLS relays are employed

[20] NPCC Directory # 12, *supra* note 12.

throughout the region. Although the most common feature is a voltage inhibit, other inhibit schemes utilizing current and time were also revealed. Additionally, the application of the voltage inhibit function was not consistent across the region.

Accordingly, the drafting team developed a requirement for each Planning Coordinator to review and coordinate the development of these thresholds to insure that they are consistent with the goal of an effective regional UFLS program.

5) Generator Applicability:

The drafting team considered the unique nature of UFLS with respect to the critical issue of maintaining proper generator coordination for all units determined to be critical to the support of the UFLS program performance characteristics. The NPCC SS-38 Working Group's assessments and recommendations were developed into a requirement that will allow the Planning Coordinators to identify generation facilities within its Planning Coordinator Area that are considered critical to the program's performance.

6) Coordination with NERC PRC-006-1.

The NPCC drafting team developed PRC-006-NPCC-1 in a manner that coordinated with NERC Reliability Standard PRC-006-1 — Automatic Underfrequency Load Shedding. In some cases, draft requirements were eliminated from the Regional Reliability Standard since PRC-006-1 already includes a requirement in place for these program attributes (e.g. perform a program design assessment every 5 years). In other cases the requirements in the Regional Standard enhance the existing requirements in the NERC Standard as a necessary requirement for the Regional program. For example, NERC PRC- 006-1 has a requirement to "establish islands" and PRC -006-NPCC-1 has a

requirement to "use islands to aggregate load." In still other cases, the drafting team developed requirements to be included in the Regional Standard that were not covered in NERC's PRC-006-1 and which were critical to the performance of the Regional program, such as inhibit thresholds and time delay characteristics on UFLS relays.

**Violation Risk Factors and Violation Severity Levels:**

The proposed Regional Reliability Standard contains both VRFs and VSLs. VRFs and VSLs are assigned to each requirement in the standard. The VRFs and VSLs for this standard were developed and reviewed for consistency with NERC and FERC guidelines.[21] Analyses of the assigned VRFs and VSLs to this standard are included in **Exhibit E**.

## VI. CONCLUSION

For the reasons stated above, NERC respectfully requests that FERC approve the proposed PRC-006-NPCC-1 Regional Reliability Standard and the associated proposed VRFs and VSLs included in **Exhibit A** to this filing in accordance with Section 215(d)(1) of the FPA and Part 39.5 of FERC's regulations. NERC requests that these approvals be made effective in accordance with the implementation plan for PRC-006-NPCC-1 included in **Exhibit A** to this filing.

Respectfully submitted,

*/s/ Andrew M. Dressel*
Andrew M. Dressel
*Attorney for North American Electric Reliability Corporation*

[21] *See Order on Violation Risk Factors*, 119 FERC ¶ 61,145 (2007) and *Order on Violation Severity Levels Proposed by the Electric Reliability Organization*, 123 FERC ¶ 61,284 (2008).

## 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 4th day of May, 2012.

*/s/ Andrew M. Dressel*
Andrew M. Dressel
*Attorney for North American Electric Reliability Corporation*

**Exhibit A**

PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding Regional Reliability Standard Proposed and Implementation Plan for Approval

## A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-NPCC-1

3. **Purpose:** To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.

4. **Applicability:**

   **4.1.** Generator Owner

   **4.2.** Planning Coordinator

   **4.3.** Distribution Provider

   **4.4.** Transmission Owner

5. **(Proposed) Effective Date:** To be established.

## B. Requirements

**R1** Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS). [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R2** Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3** Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1. [Violation Risk Factor: Low] [Time Horizon: Long Term Planning]

**R4** Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds,

total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R5** Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in UFLS Attachment C, Table 1 if applicable and

5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.

5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.4 Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.

**R6** Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program

that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R7** Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay:

7.1 Eastern Interconnection – 100 ms

7.2 Québec Interconnection – 200 ms

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R8** Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R9** Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

**R10** Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

**R11** Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

**R12** Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

**R13** Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R14** Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

**R15** Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

15.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1.

**R16** Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

**R17** Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R18** Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**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 and licensing limitations but not greater than 57.8Hz.

19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 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.

**R20** The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.

20.2 The buses at which the Load is modeled in the NPCC library power flow case.

20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.

20.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.

20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

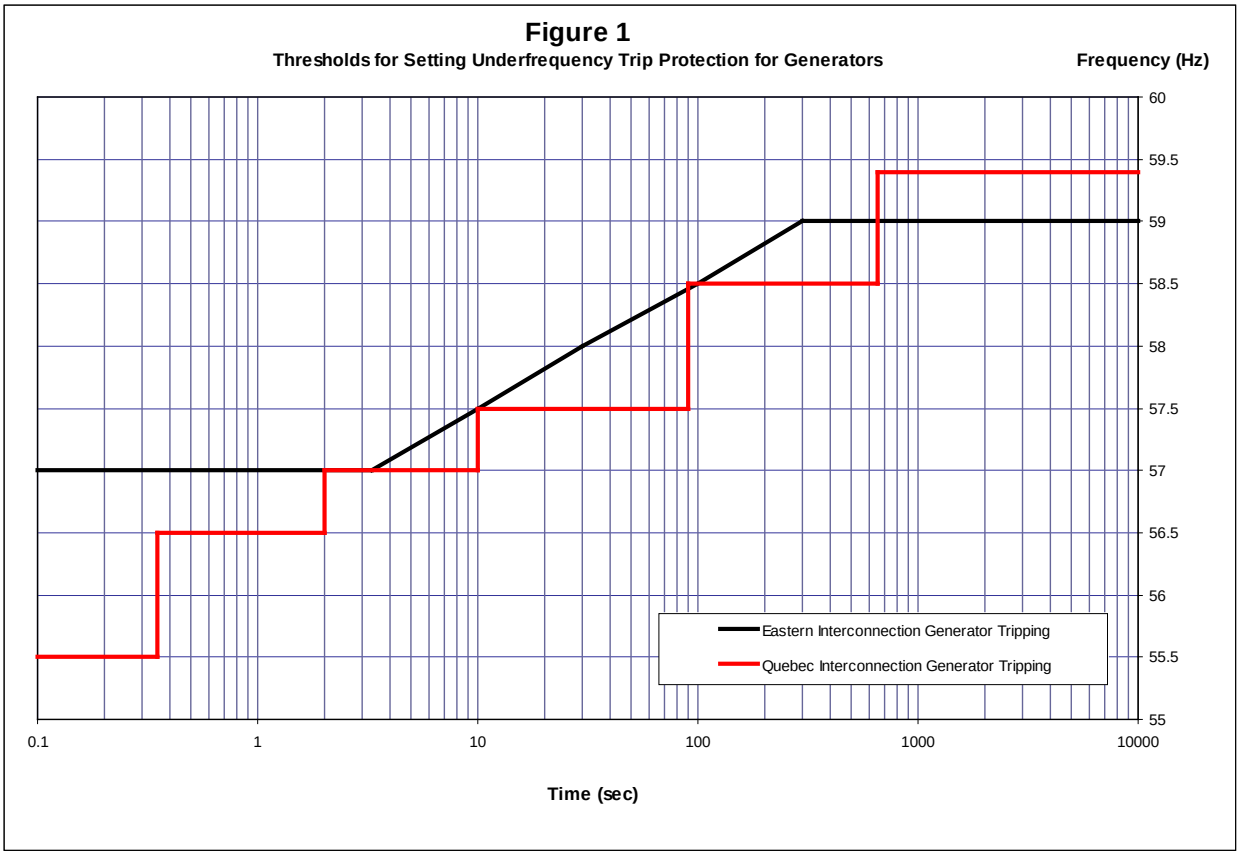
**R21** Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R22** Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R23** Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

**Figure 1**

**Thresholds for Setting Underfrequency Trip Protection for Generators**



## C. Measures

**M1** Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

**M2.** Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

**M3** Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

**M4** Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (Attachment C Tables 1-3).

**M5** Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

**M6** Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (Attachment C Table 4).

**M7** Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.

**M8** Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

**M9** Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

**M10** Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.

**M11** Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.

**M12** Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.

**M13** Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.

**M14** Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.

**M15** Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.

**M16** Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.

**M17** Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R17.

**M18** Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R18.

**M19** Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

**M20** Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

**M21** Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

**M22** Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

**M23** Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement 23.

## 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 Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,10, 11, and 12.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 8, 9, 20, and 21.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 18, 22, and 23.

The Generator Owner shall keep evidence for three calendar years for Measures 13, 14, 15, 16, and 19.

### 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

| Requirement | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| **R1** | N/A | **N/A** | Planning Coordinator did not establish requirements for entities aggregating their UFLS programs.<br>or<br>Did not establish requirements for compensatory load shedding. | Planning Coordinator did not establish requirements for entities aggregating their UFLS programs and did not establish requirements for compensatory load shedding. |
| **R2** | The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies. | The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies. | The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies. | The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 60 days after completion of the system studies.<br>or<br>The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program. |
| **R3** | The Planning Coordinator provided the requested information, but did so more than 30 days but less than 41 days to the requesting entity. | The Planning Coordinator provided the requested information, but did so more than 40 days but less than 51 days to the requesting entity. | The Planning Coordinator provided the requested information, but did so more than 50 days but less than 61 days to the requesting entity. | The Planning Coordinator provided the requested information, but did so more than 60 days after the request.<br>or<br>The Planning Coordinator failed to provide the requested information. |

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| **R4** | N/A | N/A | N/A | The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables. |
| | | | | |
| **R5** | N/A | The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table | The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or | The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load. |

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| | | 2 only, the need to deviate from providing two stages of UFLS. | Transmission Owner to comply with the appropriate table. | |
| | | | | |
| **R6** | N/A | N/A | T | The Distribution Provider or Transmission Owner in the Québec Interconnection portion of NPCC did not implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or did not collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. |
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| **R7** | N/A | N/A | N/A | The Distribution Provider or Transmission Owner failed to set |

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| | | | | an underfrequency relay that is part of its region's UFLS program as specified in Requirement R7. |
| **R8** | | N/A | The Planning Coordinator developed inhibit thresholds as specified in Requirement R8 but did not perform the review once per calendar year. | The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R8. |
| **R9** | The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds. | The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds. | The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds. | The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds.<br>or<br>The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds. |
| **R10** | N/A | N/A | N/A | The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with Requirement R9. |

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| **R11** | The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator. | The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator. | The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator. | The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator.<br>or<br>The Distribution Provider or Transmission Owner did not develop its implementation plan. |
| **R12** | | | | The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year. |
| **R13** | N/A | N/A | N/A | The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted. |

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| **R14** | The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator's request. | The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator's request. | The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator's request. | The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75days after the Planning Coordinator's request.<br>or<br>The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator. |
| **R15** | N/A | N/A | The Generator Owner did not fulfill the obligation of Requirement R15; Part 15.1 OR did not fulfill the obligation of Requirement R15, Part 15.2. | The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1 and did not fulfill the obligation of Requirement R15, Part 15.2. |
| **R16** | N/A | The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.2. | The Generator Owner did not fulfill the obligation of Requirement R16; Part 16.1 OR did not fulfill the obligation of Requirement R16, Part 16.3. | The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.1 and did not fulfill the obligation of Requirement R16, Part 16.3. |

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| **R17** | N/A | N/A | N/A | The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required. |
| **R18** | N/A | N/A | N/A | The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required. |
| **R19** | N/A | The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.3. | The Generator Owner did not fulfill the obligation of Requirement R19; Part 19.1 OR did not fulfill the obligation of Requirement R19, Part 19.2. | The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.1 and did not fulfill the obligation of Requirement R19, Part 19.2. |
| | | | | |
| **R20** | The Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5. | The Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5. | The Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5. | The Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5. |

| | | | | |
|---|---|---|---|---|
| **R21** | N/A | N/A | N/A | The Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements. |
| **R22** | N/A | N/A | N/A | The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator. |
| **R23** | The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator. | The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator. | The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator. | The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator.<br>or<br>The Distribution Provider. Transmission Owner or Generator Owner did not develop its implementation plan. |

## PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements:

1. The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate, as identified in Requirement R1

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.

    2.2 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4..

    2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest

frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

## PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has underfrequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

## PRC-006-NPCC-1 Attachment C

**UFLS Table 1: Eastern Interconnection**

Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

| Frequency Threshold (Hz) | Total Nominal Operating Time (s)[1] | Load Shed at Stage as % of TO or DP Load | Cumulative Load Shed as % of TO or DP Load |
|---|---|---|---|
| 59.5 | 0.30 | 6.5 – 7.5 | 6.5 – 7.5 |
| 59.3 | 0.30 | 6.5 – 7.5 | 13.5 – 14.5 |
| 59.1 | 0.30 | 6.5 – 7.5 | 20.5 – 21.5 |
| 58.9 | 0.30 | 6.5 – 7.5 | 27.5 – 28.5 |
| 59.5 | 10.0 | 2 – 3 | 29.5 – 31.5 |

**UFLS Table 2: Eastern Interconnection**

Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

| UFLS Stage | Frequency Threshold (Hz) | Total Nominal Operating Time(s)[1] | Load Shed at Stage as % of TO or DP Load | Cumulative Load Shed as % of TO or DP Load |
|---|---|---|---|---|
| 1 | 59.5 | 0.30 | 14-25 | 14-25 |
| 2 | 59.1 | 0.30 | 14-25 | 28-50 |

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

**UFLS Table 3: Eastern Interconnection**

Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

| UFLS Stage | Frequency Threshold (Hz) | Total Nominal Operating Time (s)[1] | Load Shed at Stage as % of TO or DP Load | Cumulative Load Shed as % of TO or DP Load |
|---|---|---|---|---|
| 1 | 59.5 | 0.30 | 28-50 | 28-50 |

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

**UFLS Table 4: Quebec Interconnection**

| | Rate | Frequency (Hz) | MW at peak (*Load must be fixed at all times when above 60% of peak load..) | Mvar at peak | Total Nominal Operating Time (s) [2] |
|---|---|---|---|---|---|
| Threshold Stage 1 | —— | 58.5 | 1000* | 1000 | 0.30 |
| Threshold Stage 2 | —— | 58.0 | 800* | 800 | 0.30 |
| Threshold Stage 3 | —— | 57.5 | 800 | 800 | 0.30 |
| Threshold Stage 4 | —— | 57.0 | 800 | 800 | 0.30 |
| Threshold Stage 5 (anti-stall) | —— | 59.0 | 500 | 500 | 20.0 |
| Slope Stage 1 | -0.3 Hz/s | 58.5 | 400 | 400 | 0.30 |
| Slope Stage 2 | -0.4 Hz/s | 59.8 | 800* | 800 | 0.30 |
| Slope Stage 3 | -0.6 Hz/s | 59.8 | 800* | 800 | 0.30 |
| Slope Stage 4 | -0.9 Hz/s | 59.8 | 800 | 800 | 0.30 |

2. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.

**Exhibit B**

Complete Development Record of Proposed PRC-006-NPCC-1 Automatic Underfrequency Load Shedding Regional Reliability Standard

| Regional Reliability Standards - Under Development | | | | |
|---|---|---|---|---|
| **Standard No.** | **Title** | **Regional Status** | **Dates** | **NERC Status** |
| **Northeast Power Coordinating Council (NPCC)** | | | | |
| PRC-006-NPCC-01 | Automatic Underfrequency Load Shedding Program | NERC Board Adopted February 9, 2012 | 11/22/11-12/22/11 | Info **(12)**<br><br>Submit Comments<br><br>Comment Form **(11)**<br><br>PRC-006-NPCC-1**(10)**<br><br>Implementation Plan **(9)**<br><br>Comments Received **(8)**<br><br>Consideration of Comments **(7)** |
| | | | 01/11/11-02/24/11 | Submit Comments<br><br>Comment Form **(6)**<br><br>PRC-006-NPCC-1 **(5)**<br><br>Implementation Plan **(4)**<br><br>Consideration of Comments **(3)**<br><br>PRC-006-NPCC-1 **(2)**<br><br>Implementation Plan **(1)** |

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# PRC-006-NPCC-1 Automatic Underfrequency Load Shedding

# Implementation Plan

**Background:**

The purpose of this draft Regional Standard is to ensure the development and maintenance of an effective and coordinated Automatic Underfrequency Load Shedding program in order to preserve the reliability and integrity of the bulk power system during declining system frequency events.

In the developing the Implementation Plan for PRC-006-NPCC-01 the Standard Drafting Team considered the following:

1. The requirements listed in this Regional Standard are intended to cover all aspects of the UFLS program. The Regional Standard Drafting Team (RSDT) coordinated its development with the draft NERC UFLS Standard PRC-006. The intent of this Regional Standard is to be more stringent than the continent wide standard while incorporating specific program characteristics into the requirements.
2. The Implementation Plan for 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.

**Effective Dates:**

Eastern Interconnection & Québec Interconnection Portions of NPCC Excluding the Independent Electricity System Operator (IESO) Planning Coordinator Area of NPCC in Ontario, Canada.

**1**. The effective date for requirements R1, R2, R3, R4, R5, R6, R7, R8, and R9 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than Jan 1, 2016 to allow for the existing implementation plan to be completed.

**2.** The effective date for requirements R10 through R27 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

Independent Electricity System Operator (IESO) Planning Coordinator's Area of NPCC in Ontario, Canada

**1.** Effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

**References:**

- 2006 Assessment of UFLS Adequacy Part 3 Assessment of Program Modifications.
- SS38 Underfrequency Load Shedding Support Studies

**NPCC Criteria:**

- Directory #12 Underfrequency Load Shedding Program Requirements.
- A-7 NPCC Glossary of Terms.

## 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. NPCC Regional Standards Committee (RSC) authorized posting UFLS RSAR development on August 20, 2008.
2. UFLS RSAR posted on NPCC website on August 25, 2008.
3. NPCC Reliability Coordinating Committee (RCC) approved the Task Force on System Studies (TFSS) as the lead task force to initiate drafting a UFLS Regional Standards on September 4, 2008.
4. NPCC UFLS Regional Standard Drafting Team initial meeting on January 27, 2009.
5. First draft posted on the NPCC Website July 13, 2009 for a 45 day comment period.
6. Second draft posted on the NPCC Website May 26, 2010 for a 45 day comment period.

**Description of Current Draft:**

This is the third draft of the proposed standard.

**Future Development Plan:**

| Anticipated Action | Anticipated Date |
|---|---|
| 1. Post the initial draft of the standard for 45 day comment period. | July 13, 2009 to August 27, 2009 |
| 2. Respond to comments on the first posting and post revised standard and implementation plan for a 45 day comment period. | September 2009 to May 2010<br><br>May 26, 2010 to July 9th, 2010 |
| 3. Respond to comments on the 2nd posting. | July 2010 to October 2010 |
| 4. Obtain RSC approval to move the standard forward to balloting. | November 2010 |
| 5. Post the standard and implementation plan for a 30 day pre ballot review. | December 2010 |
| 6. Conduct a ten day ballot. | December 2010 |

| | |
|---|---|
| | |
| 7. Respond to ballot comments and post revised standard and implementation plan for a 45 day comment period. | May, 2011. |
| 8. Respond to comments on the 3rd posting. | July 2011 |
| 9. Obtain RSC approval to move the standard forward to balloting. | August 2011 |
| 10. Post the standard and implementation plan for a 30 day pre ballot review. | August 2011 |
| 11. Conduct a ten day ballot. | September 2011 |
| 12. Membership Approval. | September 2011. |
| | |
| | |

## 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 NERC 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 NPCC Glossary.*

*In the standards, defined terms are indicated with its first letter capitalized.*

## A. Introduction

**1. Title:** **Automatic Underfrequency Load Shedding**

**2. Number:** PRC-006-NPCC-1

**3. Purpose:** To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.

**4. Applicability:**

**4.1.** Generator Owner

**4.2.** Planning Coordinator

**4.3.** Distribution Provider

**4.4.** Transmission Owner

**5. (Proposed) Effective Date:** To be established.

## B. Requirements

**R1** Each Planning Coordinator shall conduct system studies and/or use real time power flow data captured from actual system events to identify anticipated islands within the NPCC region to establish requirements for entities aggregating their UFLS programs in Requirement R3 and R4 and requirements for compensatory load shedding in Requirement R18. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R2 Each Planning Coordinator shall, in accordance with its system studies, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R3** Each Planning Coordinator shall provide to Transmission Owners, Distribution Providers, and /or Generator Owners within thirty days upon written request the information on anticipated islands derived from each Planning Coordinator's system studies as determined by Requirement R1 and /or real time power flow data pertinent to requirements for aggregating UFLS programs and/or providing for compensatory load shedding. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R4** Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program, reflecting normal operating conditions excluding outages, for its Facilities or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in one of the following tables: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

- Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

**UFLS Table 1:**

| UFLS Stage | Frequency Threshold (Hz) | Total Nominal Operating Time (s) | Load Shed at Stage as % of TO or DP Load | Cumulative Load Shed as % of TO or DP Load |
|---|---|---|---|---|
| 1 | 59.5 | 0.30 | 6.5 – 7.5 | 6.5 – 7.5 |
| 2 | 59.3 | 0.30 | 6.5 – 7.5 | 13.5 – 14.5 |
| 3 | 59.1 | 0.30 | 6.5 – 7.5 | 20.5 – 21.5 |
| 4 | 58.9 | 0.30 | 6.5 – 7.5 | 27.5 – 28.5 |
| Anti-Stall | 59.5 | 10.0 | 2 – 3 | 29.5 – 31.5 |

- Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

**UFLS Table 2:**

| UFLS Stage | Frequency Threshold (Hz) | Total Nominal Operating Time (s) | Load Shed at Stage as % of TO or DP Load | Cumulative Load Shed as % of TO or DP Load |
|---|---|---|---|---|
| 1 | 59.5 | 0.30 | 14-25 | 14-25 |
| 2 | 59.1 | 0.30 | 14-25 | 28-50 |

- Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

**UFLS Table 3:**

| UFLS Stage | Frequency Threshold (Hz) | Total Nominal Operating Time (s) | Load Shed at Stage as % of TO or DP Load | Cumulative Load Shed as % of TO or DP Load |
|---|---|---|---|---|
| 1 | 59.5 | 0.30 | 28-50 | 28-50 |

**R5** Each Distribution Provider or Transmission Owner that must arm its load to trip on under frequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on their total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning

5.1 Inform their Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 1 if applicable and

5.2 Provide their Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of UFLS Table 1 will not have a significant adverse impact on the bulk power system.

5.3 Inform their Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.4 Provide their Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Table 2 or Table 3

**R6** Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC with peak net Load connected to its Facilities shall ensure that the total nominal operating time includes the under frequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time, such that: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

6.1 The under frequency relay operating time shall be measured from the time the frequency passes through the frequency threshold set point, using a test rate of linear frequency decay of 0.2 Hz per second.

6.2 The underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second if the relay operating time is dependent on the rate of frequency decay.

**R7** Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in the following table: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**UFLS Table 4**

| | Rate | Frequency (Hz) | MW at peak (*Load must be fixed at all times.) | Mvar at peak | Total Nominal Operating Time (s) |
|---|---|---|---|---|---|
| Threshold Stage 1 | —— | 58.5 | 1000* | 1000 | 0.30 |
| Threshold Stage 2 | —— | 58.0 | 800* | 800 | 0.30 |
| Threshold Stage 3 | —— | 57.5 | 800 | 800 | 0.30 |
| Threshold Stage 4 | —— | 57.0 | 800 | 800 | 0.30 |
| Threshold Stage 5 (anti-stall) | —— | 59.0 | 500 | 500 | 20.0 |
| Slope Stage 1 | -0.3 Hz/s | 58.5 | 400 | 400 | 0.30 |
| Slope Stage 2 | -0.4 Hz/s | 59.8 | 800* | 800 | 0.30 |
| Slope Stage 3 | -0.6 Hz/s | 59.8 | 800* | 800 | 0.30 |
| Slope Stage 4 | -0.9 Hz/s | 59.8 | 800 | 800 | 0.30 |

**R8** Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC with peak net load connected to its Facilities shall insure that the total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R9** Each Distribution Provider and Transmission Owner shall set their underfrequency relays with the following minimum time delay:

9.1 Eastern Interconnection – 100 ms

9.2 Québec Interconnection – 200 ms

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R10** Each Planning Coordinator shall develop, implement and maintain a program to establish the appropriate inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS Program to insure that the inhibit settings do not adversely affect the UFLS program. [Violation Risk Factor: High] [Time Horizon: Long Term Planning

**R11** Each Planning Coordinator shall provide to Transmission Owners and Distribution Providers within its program area the specific inhibit thresholds applicable to each Transmission Owner or Distribution Providers within 30 days of the initial determination of the required inhibit threshold settings or for changes to those settings. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

**R12** Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R11. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

**R13** Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R11. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

**R14** Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net load that would be shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak during the previous year, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

**R15** Each Generator Owner shall set each generator under frequency trip relay, if so equipped, below the appropriate generator under frequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R18 and R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R16** Each Generator Owner shall transmit the generator under frequency trip setting and time constant to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

**R17** Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

17.1 Ensure that the generating unit does not trip directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

17.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during under frequency conditions above the appropriate generator under frequency trip protection settings threshold curve in Figure 1.

17.3 Transmit the generator underfrequency trip setting and time constant to the Planning Coordinator.

**R18** Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

18.1 Set the underfrequency protection to operate at the lowest frequency possible as demonstrated by the plant design and licensing limitations..

18.2 Transmit the existing under frequency settings and any changes to the under frequency settings along with the technical basis for the settings to the Planning Coordinator.

18.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

**R19** Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the methodology described in Attachment A to determine the compensatory load shedding that is required in Requirement R18.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R20** Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the methodology described in Attachment B to determine the compensatory load shedding that is required in Requirement R18.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R21** Each Generator Owner of existing nuclear generating plants with units that have under frequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, are required to adhere to the following: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

21.1 Set the under frequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.

21.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

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

**R22** Each Transmission Owner and Distribution Provider shall annually provide, with no more than 15 months between updates, its UFLS program data to its Planning Coordinator in accordance with R23 for inclusion in the Planning Coordinator's data base. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

**R23** Each Planning Coordinator shall develop and maintain its UFLS program data base. The Planning Coordinator shall update its UFLS program database within four months of receiving the Requirement R22 information. This data base shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

23.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak the corresponding frequency threshold and time delay settings.

23.2 The buses at which the Load is modeled in the NPCC library power flow case.

23.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.

23.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.

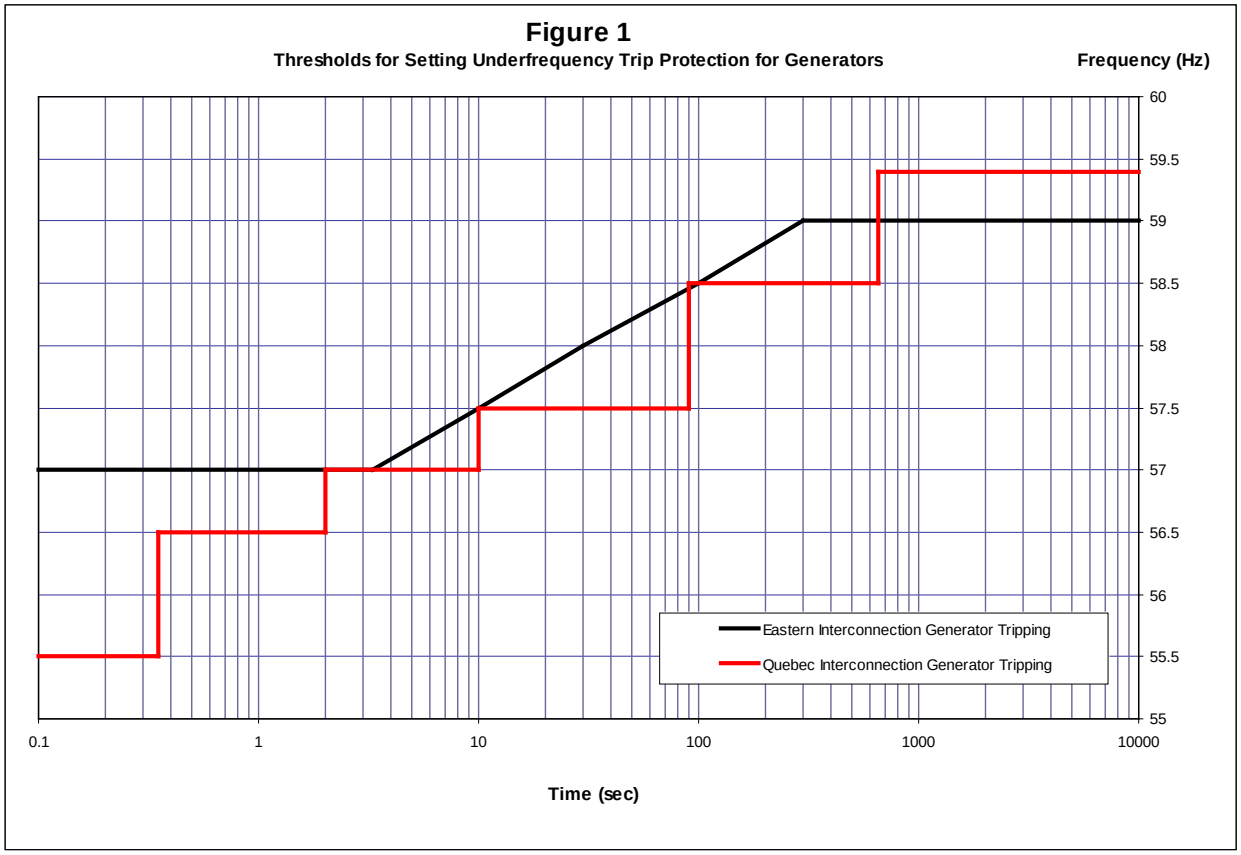
23.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

**R24** Each Planning Coordinator shall assess that the NPCC UFLS program requirements within its Planning Coordinator area are satisfied as implemented by Transmission Owners, Distribution Providers, and Generator Owners. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R25** Each Planning Coordinator shall notify Distribution Providers, Transmission Owners, and Generator Owners within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R26** Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R25. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R27** Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R25. [Violation Risk Factor: High] [Time Horizon: Operations Planning]


Figure 1
Thresholds for Setting Underfrequency Trip Protection for Generators
Frequency (Hz)
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
0.1
1
10
100
1000
10000
Time (sec)
Eastern Interconnection Generator Tripping
Quebec Interconnection Generator Tripping

## C. Measures

**M1** Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

**M2.** Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

**M3** Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

**M4** Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4.

**M5** Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

**M6** Each Distribution Provider and Transmission Owner shall have evidence such as reports, data sheets and other test documentation that demonstrates that it meets Requirement R6.

**M7** Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R7.

**M8** Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as reports, data sheets and other test documentation that demonstrates that it meets Requirement R8.

**M9** Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R9.

**M10** Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R10.

**M11** Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R11.

**M12** Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R12.

**M13** Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R13.

**M14** Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R14.

**M15** Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R15.

**M16** Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R16

**M17** Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R17.

**M18** Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have under frequency tripping that is not compliant with Requirement R14 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R18.

**M19** Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R19.

**M20** Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R20.

**M21** Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R21.

**M22** Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets and other dated documentation that demonstrates that it meets Requirement R22.

**M23** Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R23.

**M24** Each Planning Coordinator shall provide evidence such as reports, system studies and/or real time power flow data captured from actual system events that demonstrates that it meets the requirements of R24.

**M25** Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R25.

**M26** Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R26.

**M27** Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement R27

## 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 Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,8,9,12,13,14, and 22.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 10, 11, 19, 23, 24, and 25.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measure 20, 26, and 27.

The Generator Owner shall keep evidence for three calendar years for Measures 15,16,17,18, and 21.

#### 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

| Requirement | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| **R1** | N/A | **N/A** | N/A | The Planning Coordinator did not conduct system studies or use real time power flow data captured from actual system events to identify anticipated islands within the NPCC region used to establish requirements for entities aggregating their UFLS programs, and requirements for compensatory load shedding. |
| **R2** | N/A | N/A | N/A | The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program. |
| **R3** | N/A | N/A | N/A | The Planning Coordinator failed to provide to Transmission Owners, Distribution Providers, and /or Generator Owners within thirty (30) days upon written request the information on anticipated islands derived from each Planning Coordinator's system studies as determined by Requirement R1 and /or real time power flow data pertinent to requirements for aggregating |

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| | | | | UFLS programs and/or providing for compensatory load shedding. |
| **R4** | N/A | N/A | N/A | The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables. |
| **R5** | N/A | The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4, as applicable depending on their total peak net Load, butdid not inform the Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table 2 only, the need to deviate from | The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4, as applicable depending on their total peak net Load, but<br><br>did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution | The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4, as applicable depending on their total peak net Load. |

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| | | providing two stages of UFLS. | Provider or Transmission Owner to comply with the appropriate table. | |
| **R6** | N/A | N/A | The Distribution Provider or Transmission Owner in the Eastern Interconnection portion of NPCC with peak net Load connected to its Facilities shall ensure that the total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time, but did not measure the underfrequency relay operating time from the time the frequency passes through the frequency threshold set point, using a test rate of linear frequency decay of 0.2 Hz per second, OR the measurement and any subsequent testing of the UFLS relays did not utilize a test rate of linear frequency decay of 0.2 Hz per second if the relay operating times is dependent on the rate of frequency decay. | The Distribution Provider or Transmission Owner in the Eastern Interconnection portion of NPCC with peak net Load connected to its Facilities did not ensure that the total nominal operating time included the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. |

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| **R7** | N/A | N/A | N/A | The Distribution Provider or Transmission Owner did not implement an automatic UFLS program for its facilities, or did not implement collectively by the mutual agreement with one or more Distribution Providers and Transmission Owners within the same island an aggregated automatic UFLS program based on the frequency thresholds, slopes, total nominal operating time, and the amounts shown in the table. |
| **R8** | N/A | N/A | N/A | The Distribution Provider or Transmission Owner did not ensure that total nominal operating time included the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time, or the underfrequency relay operating time was not measured from the time when the frequency passes through the frequency threshold set point. |
| **R9** | N/A | N/A | N/A | The Distribution Provider or Transmission Owner failed to set their underfrequency relays with the minimum time delay requirement. |
| **R10** | N/A | N/A | N/A | The Planning Coordinator failed to develop, implement, and maintain a program to establish the appropriate voltage inhibit |

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| | | | | threshold to be used within its region's UFLS program. |
| **R11** | N/A | N/A | N/A | The Planning Coordinator failed to provide to Transmission Owners and Distribution Providers within its program area the specific inhibit thresholds applicable to each Transmission Owner or Distribution Provider within thirty (30) days of the initial determination of the required inhibit threshold settings or for changes to those settings. |
| **R12** | N/A | N/A | N/A | The Distribution Provider or Transmission Owner failed to implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R11. |
| **R13** | N/A | N/A | N/A | The Distribution Provider or Transmission Owner shall develop and submit an implementation plan within ninety (90) days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R11. |
| **R14** | The Transmission Owner or Distribution Provider exceeded the annual documentation | The Transmission Owner or Distribution Provider exceeded the annual documentation | The Transmission Owner or Distribution Provider exceeded the annual documentation submission | The Transmission Owner or Distribution Provider did not provide documentation to its |

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|---|---|---|---|---|
| | submission to its Planning Coordinator by up to thirty (30) days, OR exceeded by up to thirty (30) the fifteen (15) months between updates provided to its Planning Coordinator of the actual net load that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year. | submission to its Planning Coordinator by up to sixty (60) days, OR exceeded by up to sixty (60) days the fifteen (15) months between updates provided to its Planning Coordinator of the actual net load that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year. | to its Planning Coordinator by up to ninety (90) days, OR exceeded by up to ninety (90) the fifteen (15) months between updates provided to its Planning Coordinator of the actual net load that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year. | Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year. |
| **R15** | N/A | N/A | N/A | The Generator Owner failed to ensure that its generating units do not trip for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve unless exempted. |
| **R16** | N/A | N/A | N/A | The Generator Owner did not transmit the generator underfrequency trip setting and time constant to its Planning Coordinator within forty-five (45) days of the Planning Coordinator's request. |
| **R17** | N/A | N/A | The Generator Owner did not transmit the generator underfrequency trip setting and time setting to the Planning | The Generator Owner failed to design auxiliary systems or devices used for the control and protection of auxiliary systems |

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|---|---|---|---|---|
| | | | Coordinator. | necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve. |
| **R18** | N/A | N/A | N/A | The Generator Owner of existing non-nuclear units in service prior to the effective date of this standard, and which have underfrequency tripping set to trip above the curve, did not set the underfrequency protection to operate at the lowest frequency possible as demonstrated by the plant design and licensing limitations, OR did not transmit the initial underfrequency settings and any changes to the underfrequency setting s and the technical basis for those settings to the Planning Coordinator. OR did not have compensatory load shedding that was adequate to compensate for the loss of their generator due to early tripping. |
| **R19** | N/A | N/A | N/A | The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required. |
| **R20** | N/A | N/A | N/A | The Generator Owner, Distribution Provider, or |

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|---|---|---|---|---|
| | | | | Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required. |
| **R21** | N/A | N/A | N/A | The Generator Owner of existing boiling water nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve based on their licensing design basis did not set the protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations, but not greater than 57.8Hz., OR reduce the frequency trip setting tolerance on those units with threshold setting tolerances greater than +0.1Hz., OR did not transmit the initial frequency trip settings or any changes to the settings to the Planning Coordinator. |
| **R22** | The Transmission Owner or Distribution Provider exceeded the annual documentation submission to its Planning Coordinator by up to thirty (30) days, OR exceeded by up to thirty (30) days the fifteen (15) months between updates provided to its Planning Coordinator of UFLS program data. | The Transmission Owner or Distribution Provider exceeded the annual documentation submission to its Planning Coordinator by up to sixty (60) days, OR exceeded by up to sixty (60) days the fifteen (15) months between updates provided to its Planning Coordinator of UFLS program | The Transmission Owner or Distribution Provider exceeded the annual documentation submission to its Planning Coordinator by up to ninety (90) days, OR exceeded by up to ninety (90) days the fifteen (15) months between updates provided to its Planning Coordinator of UFLS program data. | The Transmission Owner or Distribution Provider did not provide its UFLS program data or updates to its Planning Coordinator. |

| | | | | |
|---|---|---|---|---|
| | | data. | | |
| **R23** | The Planning Coordinator did not update its UFLS program data base within four months of receiving the requisite information, or did not have data for one of the parameters listed in 23.1 through 23.5. | The Planning Coordinator did not update its UFLS program data base within four months of receiving the requisite information, or did not have data for two of the parameters listed in 23.1 through 23.5. | The Planning Coordinator did not update its UFLS program data base within four months of receiving the requisite information, or did not have data for three of the parameters listed in 23.1 through 23.5 | The Planning Coordinator did not develop or maintain its UFLS program data base. |
| **R24** | N/A | N/A | N/A | The Planning Coordinator did not assess that the NPCC UFLS program requirements within its Planning Coordinator area are satisfied as implemented by Transmission Owners, Distribution Providers, and Generator Owners. |
| **R25** | N/A | N/A | N/A | The Planning Coordinator did not notify its Distribution Providers, Transmission Owners, and Generator Owners of changes to load distribution needed to satisfy UFLS program requirements. |
| **R26** | N/A | N/A | N/A | The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator. |
| **R27** | N/A | N/A | The Distribution Provider, Transmission Owner, or Generator Owner did not submit an implementation plan within ninety (90) days of the request from the | The Distribution Provider, Transmission Owner, or Generator Owner did not develop an implementation plan at the request of the Planning |

| | | | | |
|---|---|---|---|---|
| | | | Planning Coordinator. | Coordinator. |

## PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with under frequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements:

1. The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have under frequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Under frequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate, as identified in Requirement R1

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.

    2.2 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4..

    2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest

frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

## PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has under frequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Under frequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution

Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

## Consideration of Comments on PRC-006-NPCC-1 – Frequency Load Shedding

The Regional Reliability Standard PRC-006-NPCC-1 Frequency Load Shedding Drafting Team thanks all commenters who submitted comments on the first posting of the PRC-006-NPCC-1—Automatic Under frequency Load Shedding. These standards were posted for a 45-day public comment period from January 11, 2010 through February 24, 2011. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 11 sets of comments, including comments 29 different people from approximately 22 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/regional_standards/regional_reliability_standards_under_development.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 and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

## Index to Questions, Comments, and Responses

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4. Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability? …. ….14
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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 | Electric Market Policy | X | | X | | X | X | | | | |

| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. | Michael Gildea | Dominion Resources Services, Inc. | MRO | 5 |
| 2. | Louis Slade | Dominion Resources Services, Inc. | SERC | 5 |
| 3. | Connie Lowe | Dominion Resources Services, Inc. | RFC | 5 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2. | Group | Denise Koehn | Bonneville Power Administration | X | | X | | X | X | | | | |

| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. | Greg Vassallo | BPA, Transmission Customer Service Engineering | WECC | 1 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3. | Group | Pat Hervochon | Public Service Enterprise Group | X | | X | | X | X | | | | |

| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. | Kenneth Brown | PSE&G | RFC | 1, 3 |
| 2. | Dominick Grasso | PSEG Fossil | RFC | 5 |
| 3. | Peter Dolan | PSEG ER&T | RFC | 6 |

| Group/Individual | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 4. | Scott Slickers | PSEG Power NY | NPCC | 5 | | | | | | | | |
| 5. | Eric Schmidt | PSEG ER&T | NPCC | 6 | | | | | | | | |
| 6. | Clint Bogan | Odessa Power Partners | ERCOT | 5 | | | | | | | | |
| 7. | Steven Kimmish | PSEG ER&T | ERCOT | | | | | | | | | |
| 4. Group | Frank Gaffney | Florida Municipal Power Agency | X | | X | X | X | X | X | | | |

| Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|
| 1. | Timothy Beyrle | Utilities Commission of New Smyrna Beach | FRCC | 4 |
| 2. | Greg Woessner | Kissimmee Utility Authority | FRCC | 1 |
| 3. | Jim Howard | Lakeland Electric | FRCC | 3 |
| 4. | Lynne Mila | City of Clewiston | FRCC | 3 |
| 5. | Joe Stonecipher | Beaches Energy Services | FRCC | 1 |
| 6. | Cairo Vanegas | FPUA | FRCC | 4 |
| 7. | Randy Hahn | Ocala Electric Utility | FRCC | 3 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5. | Individual | Cynthia S. Bogorad | Transmission Access Policy Study Group | X | | X | X | X | X | | | | |
| 6. | Individual | Michael Lombardi | Northeast Utilities | X | | X | | X | | | | | |
| 7. | Individual | J. S. Stonecipher | City of Jacxksonville Beach dba/Beaches Energy Services | X | | | | | | | | X | |
| 8. | Individual | Dan Rochester | Independent Electricity System Operator | | X | | | | | | | | |
| 9. | Individual | Don Weaver | New Brunswick System Operator | | X | | | | | | | | |
| 10. | Individual | Rex Roehl | Indeck Energy Services | | | | | X | | | | | |
| 11. | Individual | Brian Evans-Mongeon | Utility Services Inc. | | | | | | | | X | | |

**1. Was the proposed standard developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?**

**Summary Consideration:**

| Organization | Yes or No | Question 1 Comment |
|---|---|---|
| Dominion<br>Electric Market Policy | No | PRC-006-NPCC-1 was filed concurrently at NPCC and NERC. However, the ballot for this standard has not yet passed at NPCC. Accordingly, this standard is not ripe for NERC consideration. Dominion suggests that NERC suspend this proceeding until the ballot passes at NPCC, and then reopen this proceeding for further comments based on the standard as finally approved by NPCC. |
| **Response: Thank you for your comment. As noted in the NERC Regional Reliability Evaluation Procedure the region may request that NERC consideration of the standard occur concurrent with the anticipated final public comment period in the regional entity's regional standard development process.**<br><br>http://www.nerc.com/docs/sac/rrswg/NERC_Regional_Reliability_Evaluation_Procedure.pdf | | |
| Bonneville Power Administration | Yes | |
| Transmission Access Policy Study Group | Yes | |
| Public Service Enterprise Group | | As the NPCC process is still ongoing, it is difficult to develop an opinion at this time whether that process was fair and open. |
| **Response: Thank you for your comment. As noted in the NERC Regional Reliability Evaluation Procedure the region may request that NERC consideration of the standard occur concurrent with the anticipated final public comment period in the regional entity's regional standard development process.**<br><br>http://www.nerc.com/docs/sac/rrswg/NERC_Regional_Reliability_Evaluation_Procedure.pdf | | |
| Florida Municipal Power Agency | | The NPCC process is still ongoing, but it is our understanding that so far it has been fair and open. |

| Organization | Yes or No | Question 1 Comment |
|---|---|---|
| **Response: Thank you for your comment.** | | |
| Northeast Utilities | Yes | |
| City of Jacksonville Beach dba/Beaches Energy Services | Yes | Yes, This is pretty much what we're doing now with some good success. |
| **Response: Thank you for the comment.** | | |
| Independent Electricity System Operator | Yes | |
| New Brunswick System Operator | Yes | |
| Indeck Energy Services | No | 1) None of our generating plants is a member of NPCC. One of them is not large enough to register for NERC membership and is connected at 34 kV. The pre-ballot review of the regional standard was not posted for public comment. No comment form is available on the public NPCC website. The letter announcing a webinar on 1/4/2011 was dated 1/6/2011. The letter also announced an extension of the comment period from the date of the letter to a week later. The process is patently unfair to generators or others in NPCC that are not members.<br><br>2) The standard improperly extends NERC standards to non-registered entities. NPCC's authority to implement regional reliability standards issues from its delegation agreement with NERC. NERC has chosen not to extend registration to entities <20 MW or not connected to the BES. |
| **Response: Thank you for your comment.**<br>**1) According to the NPCC Regional Standards Development Procedure the pre ballot review is not intended for comment. Additionally, the NPCC bylaws promote membership for all registered entities which allow members to actively participate in the development of regional standards.**<br>**2)The Regional Standard Drafting Team has reviewed your concerns and notes that the NERC Statement of Registry Criteria does not limit registration of generation to those greater than 20MVA. However, the applicability in Section 4 has been revised and Attachment C has been removed.** | | |

| Organization | Yes or No | Question 1 Comment |
|---|---|---|
| | | |
| Utility Services Inc. | Yes | |

**2. Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

**Summary Consideration:**

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| Dominion<br><br>Electric Market Policy | Yes | See comments (item #1) below under Question 5. |
| **Response: Thank you for your comment. Please see the response developed for item#1 Question 5.** | | |
| Bonneville Power Administration | No | |
| Public Service Enterprise Group | | No Comment |
| Florida Municipal Power Agency | Yes | FMPA questions the need for the proposed regional standard. A continent-wide UFLS standard has been drafted and approved by stakeholders and the NERC Board, and will presumably be filed at FERC in the very near future. That standard is sufficient to protect reliability; the industry should not, at this point in time, be devoting its scarce resources to developing regional standards on the same subject. Reliability Standard PRC-006-1 requires Planning Coordinators to develop UFLS programs. It does not require Regional Entities to develop separate reliability standards.<br><br>Furthermore, a regional standard on this topic could place the entities in NPCC under a double jeopardy threat since all the entities will need to comply with mandatory NERC and Regional Standards. This double jeopardy threat is exacerbated by the fact that the continent-wide standard requires a periodic review and potential change to the program every five years whereas the NPCC program locks the UFLS relay settings into a regional standard that cannot be changed without FERC approval. If those relay settings need to be changed pursuant to the continent-wide standard, there would be a conflict between the continent-wide standard and the regional standard that could only be resolved through a revision to one of the standards, which would have to be FERC-approved to go into effect. In the meantime, entities would have no choice but to be non-compliant with one of the two standards. NPCC would be better served by being consistent with |

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| | | NERC's PRC-006-1 and not developing a UFLS program as a regional standard.<br><br>.<br><br>The draft regional standard's proposed applicability to Generator Owners--including to small, otherwise unregisterable generators--highlights the proposed framework's inappropriateness in the context of continent-wide standards. NERC's PRC-006-1 does not apply to Generator Owners because the frequency protection set points are being covered in PRC-024-1, which is currently with its SDT. Covering generators in a regional PRC-006 will result in confusion and a lack of coordination, including the risk of a conflict between the regional standard and PRC-024-1. If NPCC proceeds down a path of developing a regional standard, at a minimum, applicability to generators should be removed altogether.<br><br>Furthermore, the proposed NPCC UFLS program is not robust enough to serve the overall reliability of the Eastern Interconnect. The NPCC UFLS program seems to be designed such that a 1% inaccuracy causes the UFLS program to no longer meet performance requirements. This is far too tight of a tolerance for an inherently inaccurate analysis and reflects a lack of robustness of the UFLS program. The Eastern Interconnect would be better protected from an event that causes multiple region instability by a more robust UFLS program.It seems that one of the primary drivers in designing NPCC's UFLS program is to cover the Connecticut island, with roughly 6000 MW of peak load. The SS-38 report titled "Determination of a Threshold for Generator Applicability" dated November 15, 2010 shows in its Table 1 on Page 3 that there is only a 1% margin of error in the supply / demand mismatch in the design of the program (or 60 MW).There are numerous sources of inaccuracy of greater than 1% in the analysis and design of a UFLS program. Hence, since the proposed UFLS program cannot tolerate a 1% error, it is insufficiently robust to protect reliability. A UFLS program more robust than that proposed in this regional reliability standard would benefit other regions in the Eastern Interconnect by helping to defray opportunity for cascading from one region to another.Examples of sources of inaccuracy greater than 1% include:<br><br>1. Load models are nowhere close to 1% accurate. As an industry, we are unavoidably uncertain of the extent to which electronic and power electronic equipment such as variable speed drives, compact fluorescent lighting, etc., have penetrated customer premises; we cannot know this because we cannot |

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| | | control customer behavior. In addition, we can only approximate how these devices interact with voltage and frequency excursions. An inaccurate load model showing that load decreases less by voltage than actual, for instance, could result in post-disturbance conditions with a far greater than 1% supply/demand mismatch, outside the NPCC design tolerance. If post-disturbance load is actually 60 MW more than modeled, that disparity has the same impact as tripping an additional 60 MW of generation.<br><br>2. UFLS relays are typically on individual distribution feeders, each of which have different load profiles, different distributed generation patterns, different levels of important load such as hospitals, and different levels of electronic and power electronic loads, and are in other ways dissimilar to each other and to the overall system load pattern. Hence, load diversity with respect to time of day, day of week, time of season, amount of distributed generation (e.g., generator assistance programs, net-metering and feed-in tariffs), priority of loads, composition of loads, etc., will result in a larger than 1% inaccuracy in the amount of load tripped by the UFLS program. If 60 MW too little load is shed, it has the same impact as tripping an additional 60 MW of generation.<br><br>3. The continent-wide PRC-006-1 recently approved by the BOT contains a reasonable, but arbitrary assumption of a 25% supply / demand mismatch. The fact that the NERC standard had to choose a relatively arbitrary number shows the inexactness of the science of designing a UFLS program. This inexactness runs counter to a philosophy of designing a UFLS program with only a 1% margin of error; such a UFLS program lacks the robustness of larger design tolerances.<br><br>4. Many more examples exist of inaccuracies inherent in stability studies and UFLS program design greater than 1%, such as: a) governing systems are difficult and risky to test and their performance characteristic changes with different operating conditions such as temperature, pressure and power level; and b) the partial differential equations and numerical methods that describe the stability response of the system are subject to what mathematicians call “Chaos Theory” and cannot be accurate to within 1%.NPCC mistakenly believes that a 1% design tolerance can be achieved and uses this mistaken belief to include very small generators in its UFLS program. As shown above, a 1% design tolerance cannot be achieved due to the very nature of |

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| | | variable load and other variables that cannot be modeled to within a 1% margin of error.The correct approach is to determine the range of error inherent in the variables used in performing UFLS program design. If a variable cannot be modeled to within a +/-10% accuracy bandwidth (as is likely the case of loads and load models), the UFLS program should be designed to be robust enough to tolerate this margin of error. By not designing the UFLS program with more reasonable design tolerances, the NPCC program creates unnecessary risk to the reliability of the Eastern Interconnect. |
| **Response: Thank you for your comment. The standard was developed in response to a request from NERC to satisfy FERC Order 693 issued in 2006. At that time, twenty four standards were identified as "fill in the blank" and as a result the FERC directed NERC to modify the individual standards reliance on the Regional Reliability Organization.**<br><br>**Additionally, of those twenty four standards, four were identified by NERC and the regions to be regionally specific enough to warrant the development of a regional standard and Under Frequency Load Shedding is one of those four standards.**<br><br>**The remaining comments are beyond the scope of Question#2.** | | |
| Transmission Access Policy Study Group | Yes | TAPS questions the need for the proposed regional standard. A continent-wide UFLS standard has been drafted and approved by stakeholders and the NERC Board, and will presumably be filed at FERC in the very near future. That standard is sufficient to protect reliability; the industry should not, at this point in time, be devoting its scarce resources to developing regional standards on the same subject. Reliability Standard PRC-006-1 requires Planning Coordinators to develop UFLS programs. It does not require Regional Entities to develop separate UFLS reliability standards.Furthermore, a regional standard on this topic could place the entities in NPCC under a double jeopardy threat since all the entities will need to comply with mandatory NERC and Regional Standards. This double jeopardy threat is exacerbated by the fact that the continent-wide standard requires a periodic review and potential change to the program every five years whereas the NPCC program locks the UFLS relay settings into a regional standard that cannot be changed without FERC approval. If those relay settings need to be changed pursuant to the continent-wide standard, there would be a conflict between the continent-wide standard and the regional standard that could only be resolved through a revision to one of the standards, which would have to be FERC-approved to go into effect. In the meantime, entities would have no choice but to be non-compliant with one of the two standards. NPCC would be better served by being consistent with NERC's PRC-006-1 and not developing a UFLS program as a regional standard. The draft regional standard's proposed applicability to Generator Owners--including to small, otherwise unregisterable generators--highlights the proposed framework's inappropriateness in the context of continent-wide standards. NERC's PRC-006-1 does not apply to Generator Owners because the |

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| | | frequency protection set points are being covered in PRC-024-1, which is currently with its SDT. Covering generators in a regional PRC-006 will result in confusion and a lack of coordination, including the risk of a conflict between the regional standard and PRC-024-1. If NPCC proceeds down a path of developing a regional standard, at a minimum, applicability to generators should be removed altogether.Furthermore, the proposed NPCC UFLS program is not robust enough to serve the overall reliability of the Eastern Interconnect. The NPCC UFLS program seems to be designed such that a 1% inaccuracy causes the UFLS program to no longer meet performance requirements. This is far too tight of a tolerance for an inherently inaccurate analysis and reflects a lack of robustness of the UFLS program. The Eastern Interconnect would be better protected from an event that causes multiple region instability by a more robust UFLS program.It seems that one of the primary drivers in designing NPCC's UFLS program is to cover the Connecticut island, with roughly 6000 MW of peak load. The SS-38 report titled "Determination of a Threshold for Generator Applicability" dated November 15, 2010 shows in its Table 1 on Page 3 that there is only a 1% margin of error in the supply / demand mismatch in the design of the program (or 60 MW).There are numerous sources of inaccuracy of greater than 1% in the analysis and design of a UFLS program. Hence, since the proposed UFLS program cannot tolerate a 1% error, it is insufficiently robust to protect reliability. A UFLS program more robust than that proposed in this regional reliability standard would benefit other regions in the Eastern Interconnect by helping to defray opportunity for cascading from one region to another.Examples of sources of inaccuracy greater than 1% include:1. Load models are nowhere close to 1% accurate. As an industry, we are unavoidably uncertain of the extent to which electronic and power electronic equipment such as variable speed drives, compact fluorescent lighting, etc., have penetrated customer premises; we cannot know this because we cannot control customer behavior. In addition, we can only approximate how these devices interact with voltage and frequency excursions. An inaccurate load model showing that load decreases less by voltage than actual, for instance, could result in post-disturbance conditions with a far greater than 1% supply/demand mismatch, outside the NPCC design tolerance. If post-disturbance load is actually 60 MW more than modeled, that disparity has the same impact as tripping an additional 60 MW of generation.2. UFLS relays are typically on individual distribution feeders, each of which have different load profiles, different distributed generation patterns, different levels of important load such as hospitals, and different levels of electronic and power electronic loads, and are in other ways dissimilar to each other and to the overall system load pattern. Hence, load diversity with respect to time of day, day of week, time of season, amount of distributed generation (e.g., generator assistance programs, net-metering and feed-in tariffs), priority of loads, composition of loads, etc., will result in a larger than 1% inaccuracy in the amount of load tripped by the UFLS program. If 60 MW too little load is shed, it has the same impact as tripping an additional 60 MW of generation.3. The continent-wide PRC-006-1 recently approved by the BOT contains a reasonable, but arbitrary assumption of a 25% supply / demand mismatch. The fact that the NERC standard had to choose a relatively arbitrary number shows the inexactness of the science of designing a UFLS program. This inexactness runs counter to a philosophy of designing a UFLS program with only a 1% margin of error; such a UFLS program lacks the robustness of larger design tolerances.4. Many more examples exist of inaccuracies |

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| | | inherent in stability studies and UFLS program design greater than 1%, such as: a) governing systems are difficult and risky to test and their performance characteristic changes with different operating conditions such as temperature, pressure and power level; and b) the partial differential equations and numerical methods that describe the stability response of the system are subject to what mathematicians call “Chaos Theory” and cannot be accurate to within 1%.NPCC mistakenly believes that a 1% design tolerance can be achieved and uses this mistaken belief to include very small generators in its UFLS program. As shown above, a 1% design tolerance cannot be achieved due to the very nature of variable load and other variables that cannot be modeled to within a 1% margin of error.The correct approach is to determine the range of error inherent in the variables used in performing UFLS program design. If a variable cannot be modeled to within a +/-10% accuracy bandwidth (as is likely the case with respect to loads and load models), the UFLS program should be designed to be robust enough to tolerate this margin of error. By not designing the UFLS program with more reasonable design tolerances, the NPCC program creates unnecessary risk to the reliability of the Eastern Interconnect. |
| **Response: Thank you for your comment. The standard was developed in response to a request from NERC to satisfy FERC Order 693 issued in 2006. At that time, twenty four standards were identified as "fill in the blank" and as a result the FERC directed NERC to modify the individual standards reliance on the Regional Reliability Organization.**<br><br>**Additionally, of those twenty four standards, four were identified by NERC and the regions to be regionally specific enough to warrant the development of a regional standard and Under Frequency Load Shedding was one of those four standards.**<br><br>**The remaining comments are beyond the scope of Question#2.** | | |
| Northeast Utilities | No | |
| City of Jacxksonville Beach dba/Beaches Energy Services | No | |
| Independent Electricity System Operator | No | |
| New Brunswick System Operator | No | |

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| Indeck Energy Services | | |
| Utility Services Inc. | Yes | The standard's incorporation of generation that is unregistered in the ERO Compliance activities will adversely impact reliability. The standard proposes to include generation between 1 MVA and the registration criteria. Without a thorough examination of the impacts of this generation to the compliance, it is unknown how these "new" registered entities will be dealt with. Further, the standard's requirements in certain ways is inconsistent with the underlying study that is the basis for the UFLS program. The standard requires differing curtailment requirements for load versus load being shed for compensatory generation that is above the curve. Reported data is based upon non-coincidentalized readings while the study is predicated upon coincidentalized meter readings. The standards expose Registered Entities to double jeopardy when there is a violation. Compensatory loadshedding can be difficult to achieve when there are no willing players and the objective creates financial incentives to entities to withhold from negotiations. |
| **Response: Thank you for response. The applicability in Section 4 has been revised and Attachment C has been removed.**<br><br>**Additionally, the SS-38 study represents the initial baseline for the Under Frequency program within NPCC. Each PC shall conduct and document a UFLS design assessment that determines through dynamic simulation whether the UFLS program meets the minimum performance characteristics as defined in the continent wide draft PRC-006.** | | |

**3. Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?**

**Summary Consideration:**

| Organization | Yes or No | Question 3 Comment |
|---|---|---|
| Electric Market Policy | No | |
| Bonneville Power Administration | No | Not that we are aware of.<br>**Response: Thank you for your comment.** |
| Transmission Access Policy Study Group | No | |
| Public Service Enterprise Group | | |
| Florida Municipal Power Agency | | |
| Northeast Utilities | No | |
| City of Jacxksonville Beach dba/Beaches Energy Services | No | |
| Independent Electricity System Operator | No | |
| New Brunswick System Operator | No | |
| Indeck Energy Services | Yes | It proposes to drop 50% of load in some islanded areas at frequencies above 58 hz. If they are islanded, they are no longer a risk to reliability of the system. These islanded areas may be subsidizing the larger areas at great cost and potential safety risk to these customers. |

| Organization | Yes or No | Question 3 Comment |
|---|---|---|
| **Response: Thank you for your response. The results of studies conducted by the NPCC SS38 technical committee showed that the current frequency response for the islands tested are similar to the responses obtained in Part III of the 2006 UFLS Assessment. Thus the variances proposed by the Regional Standard Drafting Team (RSDT) for the small load serving entities are acceptable according to the current levels of load served by such entities on the NPCC system.**<br><br>**SS-38 observed that the draft NPCC standard did not specify an upper limit on the amount of load to be armed for UFLS for LSE's in Table 2 and 3 of the draft standard.**<br><br>**SS-38 feels that a cumulative upper limit of 50% would keep the amount of load armed for UFLS by these LSE's (i.e. 50% at the first stage for Table #3 and 25% each at the first and third stages for Table #2) closer to the original program design while providing latitude to accommodate any constraints due to the granularity of loads on a limited numbers of feeders.**<br><br>**The data submitted for each Area showed that the amount of load in each of the small LSE categories to be small percentages of the overall peak load for current day system conditions. It is recognized that these upper limits may require revision if system conditions change and more LSEs are classified.** | | |
| Utility Services Inc. | No | |

**4. Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

**Summary Consideration:**

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| Electric Market Policy | No | |
| Bonneville Power Administration | No | |
| Public Service Enterprise Group | No | |
| Transmission Access Policy Study Group | Yes | In requirement R17, the standard would force generators that do not meet the performance requirements in the standard (non-conforming generators) to either: 1) make substantial investments to meet performance requirements imposed on them after they are already interconnected and in commercial operation, or 2) enter an agreement for compensatory load shedding with one of a limited number of entities that can offer such service, and with no market to inform pricing of such service. Either option is a significant burden on the competitiveness of these generators which results in a substantial burden on competitive markets.<br><br>Also, as discussed in response to Question 2, the 1% design tolerance desired by the NPCC UFLS program design team is a flaw in the design itself; hence, with a more reasonable design tolerance, there is no reliability reason to place this unreasonable burden on small generators.<br><br>Compensatory load shedding should NOT be allowed for two reasons: 1) the standards should not force agreements to be made; and 2) the UFLS program would become a highly complex scheme with settings that would need to change over time to reflect the status of the non-conforming generator, e.g., if the unit were off-line, then too much load would be "armed" to trip, so, those relay settings would need to be changed when the unit was offline.The complexity of a UFLS program that would have to track the status of non-conforming generators is staggering. For instance, in order to protect the 1% design tolerance of supply / demand balance that the drafters of the standard mistakenly believe is important, the UFLS relay settings would need to change every time the generator changed output. For instance, a non-conforming generator with a capacity of 300 MW would presumably have 300 MW of compensatory load shedding. If it were running at 200 MW, then we would want the 300 MW of compensatory load shedding dropped to 200 MW. How would such a |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| | | thing be possible if we are limited to a finite level of distribution circuits whose load varies minute to minute with different load patterns, with varying levels of critical loads (e.g., hospitals) and non-critical loads on those circuits? At what UFLS steps would the compensatory load shedding be adjusted? Would it be multiple steps? If the generator were providing regulation service, the relay settings would need to change minute by minute on different circuits depending on actual loads on those circuits. If the ability to make such minute-by-minute relay changes were not in place, would the generator be barred from participating in the regulation service ancillary services market, further burdening competitive markets? Compensatory load shedding is ill-conceived and highly impractical.The NERC-wide standard recently approved by the BOT takes the correct approach. Existing non-conforming generators of a sufficient size to matter should be modeled and the UFLS program be designed in a robust enough fashion to handle the non-conforming generation. |
| **Response: Thank you for your comment. The RSDT acknowledges the technical challenges of administering the compensatory load shedding program and as a result has developed requirements stating that all new units shall conform to the generator tripping curve.**<br><br>**Additionally, to address your concern regarding generators that are already interconnected and in commercial operation, non conforming generators either have existing contracts to provide for compensatory load shedding or have mitigated the conditions that would trip the unit above the appropriate generator tripping curve.**<br><br>**These, requirements are contained as criteria within the approved NPCC Directory #12 and are currently in effect throughout the NPCC region.**<br><br>**Finally, the NPCC technical committee (SS38) developed reviewed and confirmed the use of tolerances as described in the standard. These studies were reviewed and approved by the NPCC Task Force on System Studies (TFSS) and the Reliability Coordinating Committee (RCC).** | | |
| Florida Municipal Power Agency | Yes | In requirement R17, the standard would force generators that do not meet the performance requirements in the standard (non-conforming generators) to either: 1) make substantial investments to meet performance requirements imposed on them after they are already interconnected and in commercial operation, or 2) enter an agreement for compensatory load shedding with one of a limited number of entities that can offer such service, and with no market to inform pricing of such service. Either option is a significant burden on the competitiveness of these generators which results in a substantial burden on competitive markets.<br><br>Also, as discussed in response to Question 2, the 1% design tolerance desired by the NPCC UFLS program |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| | | design team is a flaw in the design itself; hence, with a more reasonable design tolerance, there is no reliability reason to place this unreasonable burden on small generators.Compensatory load shedding should NOT be allowed for two reasons: 1) the standards should not force agreements to be made; and 2) the UFLS program would become a highly complex scheme with settings that would need to change over time to reflect the status of the non-conforming generator; e.g., if the unit were off-line, then too much load would be "armed" to trip, so, those relay settings would need to be changed when the unit was off-line.The complexity of a UFLS program that would have to track the status of non-conforming generators is staggering. For instance, in order to protect the 1% design tolerance of supply / demand balance that the drafters of the standard mistakenly believe is important, the UFLS relay settings would need to change every time the generator changed output. For instance, a non-conforming generator with a capacity of 300 MW would presumably have 300 MW of compensatory load shedding. If it were running at 200 MW, then we would want the 300 MW of compensatory load shedding dropped to 200 MW. How would such a thing be possible if we are limited to a finite level of distribution circuits whose load varies minute to minute with different load patterns, with varying levels of critical loads (e.g., hospitals) and non-critical loads on those circuits? At what UFLS steps would the compensatory load shedding be adjusted? Would it be multiple steps? If the generator were providing regulation service, the relay settings would need to change minute by minute on different circuits depending on actual loads on those circuits. If the ability to make such minute-by-minute relay changes were not in place, would the generator be barred from participating in the regulation service ancillary services market, further burdening competitive markets? Compensatory load shedding is ill-conceived and highly impractical.The NERC-wide standard recently approved by the BOT takes the correct approach. Existing non-conforming generators of a sufficient size to matter should be modeled and the UFLS program be designed in a robust enough fashion to handle the non-conforming generation. |
| **Response: Thank you for your comment. The RSDT acknowledges the technical challenges of administering the compensatory load shedding program and as a result has developed requirements stating that all new units shall conform to the generator tripping curve.**<br><br>**Additionally, to address your concern regarding generators that are already interconnected and in commercial operation, non conforming generators either have existing contracts to provide for compensatory load shedding or have mitigated the conditions that would trip the unit above the appropriate generator tripping curve.**<br><br>**These requirements are contained as criteria within the approved NPCC Directory #12 and are currently in effect throughout the NPCC region.** | | |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| **Finally, the NPCC technical committee (SS38) developed reviewed and confirmed the use of tolerances as described in the standard. These studies were reviewed and approved by the NPCC Task Force on System Studies (TFSS) and the Reliability Coordinating Committee (RCC).** | | |
| Northeast Utilities | No | |
| City of Jacxksonville Beach dba/Beaches Energy Services | No | |
| Independent Electricity System Operator | No | |
| New Brunswick System Operator | No | |
| Indeck Energy Services | Yes | The standard imposed a significant burden on the customers of DP's and TO's with less than 100 MW of load by requiring substantially higher percentages of load reductions at similar frequencies. In addition, this standard is not necessary for reliability because, and is particularly burdensome, the DP's and TO's with less than 100 MW's of load are each too small to be a Reportable Disturbance within either the NYISO or ISONE. How then is reliability improved?<br><br>Also, the standard improperly extends its applicability to GO's less than 20 MW and not connected to directly to the BES. NPCC is delegated its power to develop Regional Standards under the delegation agreement with NERC. NERC has chosen not to apply its standards to any entities other than Registered Entities. Therefore, NPCC may not apply the standard to GO's that are not Registered Entities. The publicly available information does not justify the differences from continent wide standard compared to the burden on competitive markets. |
| **Response: Thank you for your comment. Entities with less than 100MWs are provided additional flexibility via wider cumulative load shedding bands. This allowance, supported by technical studies, was provided based on evidence that many smaller entities could not provide the necessary load shedding without exceeding their requirement based on their limited number of feeders available to be armed.**<br><br>**Additionally, the minimum obligation of these entities is essentially the same of entities greater than 100MWs.** | | |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| **Finally, the applicability in Section 4 has been revised and Attachment C has been removed.** | | |
| Utility Services Inc. | Yes | See answer in Q2. Generators whose protection systems trip above the curve are "required" to find load to be shed. Load could withhold such until financial incentives were offered. It is also possible that compensatory load might not be found and then the generation would be in violation of the standard. There are no guarantees of compensatory load shedding in today's competitive horizontal electric markets. |
| **Response: Thank you for your comment. The RSDT acknowledges the technical challenges of administering the compensatory load shedding program and as a result has developed requirements stating that all new units shall conform to the generator tripping curve.**<br><br>**These requirements are contained as criteria within the approved NPCC Directory #12 and are currently in effect throughout the NPCC region.** | | |

**5. Does the proposed regional reliability standard meet at least one of the following criteria?**

- **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
- **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

**Summary Consideration:**

| Organization | Yes or No | Question 5 Comment |
|---|---|---|
| Dominion<br><br>Electric Market Policy | Yes | Dominion is opposed to NPCC regional reliability standard PRC-006-1, Automatic Underfrequency Load Shedding, for the following reasons:1. The process by which a Generator Owner would arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load shed (Reference Attachment B, Step 2.2) remains unresolved. In previous comments, we noted that Dominion had polled various Transmission Owners and Distribution Providers and none were willing to offer load shed service, citing the following:<br><br>a. Implementation - load shed service does not currently exist in the Transmission Owner or Distribution Providers' tariffs. Requiring them to implement this service, would raise numerous issues, including, but not limited to the issues of determining which customers' load is shed to provide this service (retail or wholesale) and in determining 'fair value' for the price of such service. Accordingly, a requirement that these entities create and manage a new service that is not compelled by the needs of the market, would have a detrimental impact on commerce.<br><br>b. Technical difficulty - (design complexity, difficulty meeting overshoot requirements) - Shedding additional load equivalent to a non-coordinating generator would be extremely difficult to design and coordinate. The design would have to account for the real-time status and output of the generator. Otherwise, this requirement could create more problems than it attempts to solve. For example, consider a load shed program that is designed assuming the need to shed load equivalent to rated capacity for a non-coordinating generator and a frequency event occurs when this generator is off line. The program sees the frequency at the trigger level and sheds the load equivalent to the non-coordinating generator. |

| Organization | Yes or No | Question 5 Comment |
|---|---|---|
| | | However, since that generator wasn't actually on line, there is no additional loss of generation, but the MW load equivalent of the generator (that is not designed into the UFLS scheme) is lost anyway. If the UFLS program then implements the next level of designed reduction of load, this may result in a subsequent rebound in frequency. This may very well result in overshoot that is more than designed for, resulting in generator trip from over-frequency. Obviously, the more non-coordinating generators there are, the more difficult the task of coordination with UFLS schemes becomes and the more widespread the effects on customers.<br><br>c. 2. The Implementation Plan suggests that "the Drafting Team coordinated its development [of NPCC regional reliability standard PRC-006-1] with the recently approved NERC UFLS Standard PRC-006". Dominion is compelled to point out that NERC UFLS Standard PRC-006 has only attained NERC Board of Trustee approval, has not yet been approved by FERC, and is therefore not enforceable. Since there is uncertainty as to the FERC outcome, Dominion recommends that NERC suspend its review of regional reliability standard NPCC regional reliability standard PRC-006-1until continent-wide standards PRC-006 (Project 2007-01) and PRC-024 (Project 2007-09) are approved by FERC.<br><br>d. 3. The applicability of this standard to "Generator Owners with individual generating units or generating plant/facility <= 1 MVA (nameplate rating) connected at all voltage levels" does not meet the NERC Statement of Compliance Registry Criteria (Revision 5.0) or the NPCC Compliance Guidance Statement "Defining Generator Materiality for Registration;" therefore creating a registration gap. Attachment "C" attempts to close this gap by requiring these facilities to coordinate with NPCC UFLS program characteristics as mandated by their respective OATT tariff agreements. This appears inappropriate in a Regional Reliability Standard as enforcement of the OATT tariff resides with FERC, not NERC or the Regions. Therefore, as acknowledged by NPPC during the January 4, 2011 Webinar, the issue of registration for generating plants/facilities <= 1 MVA, but < the NERC Registration Criteria remains unresolved. |
| | | |

| Organization | Yes or No | Question 5 Comment |
|---|---|---|
| **Response: Thank you for your comment. The RSDT acknowledges the technical challenges of administering the compensatory load shedding and as a result has developed requirements stating that all new units shall conform to the generator tripping curve.**<br><br>**NERC has mandated the development of certain regional standards and its development cannot wait until all approvals are obtained on the NERC continent wide standard. However, the RSDT did coordinate the development of the regional standard with the progress of the continent wide standard.**<br><br>**The Regional Standard Drafting Team has reviewed your concerns and notes that the NERC Statement of Registry Criteria does not limit registration of generation to those greater than 20MVA. However, the applicability in Section 4 has been revised and Attachment C has been removed.** | | |
| Bonneville Power Administration | Yes | |
| Transmission Access Policy Study Group | Yes | |
| Public Service Enterprise Group | | |
| Florida Municipal Power Agency | | |
| Northeast Utilities | Yes | |
| City of Jacxksonville Beach dba/Beaches Energy Services | Yes | |
| Independent Electricity System Operator | Yes | |
| New Brunswick System Operator | Yes | |
| Indeck Energy Services | No | |

| Organization | Yes or No | Question 5 Comment |
|---|---|---|
| Utility Services Inc. | Yes | |

END OF REPORT

# PRC-006-NPCC-1 Automatic Underfrequency Load Shedding

# Implementation Plan

## Background:

The purpose of this draft Regional Standard is to ensure the development and maintenance of an effective and coordinated Automatic Underfrequency Load Shedding program in order to preserve the reliability and integrity of the bulk power system during declining system frequency events.

In the developing the Implementation Plan for PRC-006-NPCC-01 the Standard Drafting Team considered the following:

1. The requirements listed in this Regional Standard are intended to cover all aspects of the UFLS program. The Drafting Team coordinated its development with the recently approved NERC UFLS Standard PRC-006. The intent of this Regional Standard is to be more stringent than the continent wide standard while incorporating specific program characteristics into the requirements.
2. The Implementation Plan for this standard is the same as the existing and ongoing Implementation Plan for NPCC Directory #12.
3. The Regional Standard implementation plan will not require adherence to the annual milestones within the Directory #12 plan. However, entities will be required to be fully compliant by the end of the existing Directory #12 implementation plan.

## Effective Dates:

1. The effective date for requirements R1, R2, R3, R4, R5, R6, R7, and R8 is the first day of the first quarter following applicable regulatory approval but no earlier than Jan 1, 2016 to allow for the existing implementation plan to be completed.
2. The effective date for requirements R9 through R26 is the first day of the first quarter two years following applicable governmental and regulatory approval.

**Reference:**

- 2006 Assessment of UFLS Adequacy Part 3 Assessment of Program Modifications.
- SS38 Underfrequency Load Shedding Support Study

**NPCC Criteria:**

- Directory #12 Underfrequency Load Shedding Program Requirements.
- A-7 NPCC Glossary of Terms.

**Implementation Plans:**

- UFLS Implementation Plan for the Eastern Interconnection Portion of NPCC.
- UFLS Implementation Plan for the Québec Interconnection Portion of NPCC.

## 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 approved the SAR for posting on November 21, 2006.
2. SAR posted for comments on November 29, 2006.
3. The Standards Committee appointed a SAR Drafting Team on January 11, 2007.
4. SAR Drafting Team responds to comments, revises SAR and posts for comments on February 7, 2007.
5. SAR Drafting Team responds to comments on April 20, 2007.
6. Standards Committee approves development of Standard on April 10, 2007.
7. The Standards Committee appointed the Standard Drafting Team on April 10, 2007.
8. The Standards Drafting Team posted draft performance characteristics for comment on July 2, 2008.
9. Standards Drafting Team responds to comments, revises standard, and posts for comments on April 15, 2009.
10. Standards Committee approved the Supplemental SAR for posting on October 7, 2009 that expanded the SDT's scope to include EOP-003-1 but limiting that scope to only eliminating references to Under-frequency Load Shedding in EOP-003-1.
11. The Standards Drafting Team posted the standard for a third comment period June 11, 2010 – July 16, 2010.
12. The Standard Drafting Team conducted a pre-ballot review of the standard on June 11, 2010 – July 2, 2010
13. The Standard Drafting Team conducted an initial ballot of the standard and non-binding poll of the VRFs and VSLs on July 8, 2010 – July 17, 2010.
14. The Standard Drafting Team conducted a second ballot of the standard on July 24, 2010 – August 3, 2010.
15. The Standard Drafting Team conducted a third ballot of the standard September 24-October 4, 2010.

**Proposed Action Plan and Description of Current Draft:**

This is the recirculation ballot period of the proposed standard.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Request BOT approval | November , 2010 |
| 2. File Standard with FERC | December, 2010 |

## A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-1

3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

   **4.1.** Planning Coordinators

   **4.2.** UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

   4.2.1 Transmission Owners

   4.2.2 Distribution Providers

   **4.3** Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. **(Proposed) Effective Date:**

   **5.1.** The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals.

   **5.2.** Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

## B. Requirements

**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. *[VRF: Medium][Time Horizon: Long-term Planning]*

**R2.** Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

**2.1.** Those islands selected by applying the criteria in Requirement R1, and

**2.2.** Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

**2.3.** A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.

**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). *[VRF: High][Time Horizon: Long-term Planning]*

**3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

**3.3.1.** Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

**3.3.2.** Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

**3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

**R4.** Each Planning Coordinator shall conduct and document a UFLS design 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. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

**4.1.** Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

**4.2.** Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

**4.3.** Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

**4.4.** Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

**4.5.** Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

**4.6.** Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

**4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

**R5.** Each Planning Coordinator, whose area or portions of 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, 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: *[VRF: Medium][Time Horizon: Long-term Planning]*

- 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.

**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. *[VRF: Lower][Time Horizon: Long-term Planning]*

**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. *[VRF: Lower][Time Horizon: Long-term Planning]*

**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. *[VRF: Lower][Time Horizon: Long-term Planning]*

**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. *[VRF: High][Time Horizon: Long-term Planning]*

**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. *[VRF: High][Time Horizon: Long-term Planning]*

**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: *[VRF: Medium][Time Horizon: Operations Assessment]*

**11.1.** The performance of the UFLS equipment,

**11.2.** The effectiveness of the UFLS program.

**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. *[VRF: Medium][Time Horizon: Operations Assessment]*

**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: *[VRF: Medium][Time Horizon: Operations Assessment]*

- 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 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.

**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 *[VRF: Lower][Time Horizon: Long-term Planning]*:

**14.1.** UFLS program, including a schedule for implementation

**14.2.** UFLS design assessment

**14.3.** Format and schedule of UFLS data submittal

## C. Measures

**M1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

**M2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.

**M3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

**M4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.

**M5.** Each Planning Coordinator, whose area or portions of 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, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.

**M6.** Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per

Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

**M7.** Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

**M8.** Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

**M9.** Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.

**M10.** Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.

**M11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

**M12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

**M13.** 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 have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.

**M14.** Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, 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 per Requirement R14.

## D. Compliance

## 1. Compliance Monitoring Process

### 1.1. Compliance Enforcement Authority

Regional Entity

### 1.2. Data Retention

Each Planning Coordinator and UFLS 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:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period 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 Audit
- Self-Certification
- Spot Checking

- Compliance Violation Investigation
- Self-Reporting
- Complaint

### 1.4. Additional Compliance Information

Not applicable.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| **R1** | 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 and Regional Entity areas that may form islands.<br><br>OR<br><br>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. | 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, that may form islands. | 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. |
| **R2** | 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.<br><br>OR<br><br>The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| **R3** | 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.<br>OR<br>The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area |
| **R4** | The Planning Coordinator 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. | The Planning Coordinator 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 two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7. | The Planning Coordinator 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 three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7. | The Planning Coordinator 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.<br>OR<br>The Planning Coordinator failed to conduct and document a UFLS |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | 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 |
| **R5** | N/A | N/A | N/A | The Planning Coordinator, whose area or portions of 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. |
| **R6** | 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 once each calendar year, with no more than 15 months between maintenance activities. |
| **R7** | 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.<br>OR<br>The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| **R8** | 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.<br>OR<br>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. | 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.<br>OR<br>The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. |
| **R9** | 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. |
| **R10** | 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 required by the UFLS program and schedule for application | 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-voltage if required by the UFLS program and schedule for application | 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 program and schedule for application | 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 for application determined by the Planning |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission | determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission | determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission | Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission |
| **R11** | 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.<br>OR<br>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 one (1) of the Parts as specified in Requirement R11, Parts11.1 or 11.2. | 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.<br>OR<br>The Planning Coordinator, in whose area an islanding event resulting in system frequency 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.<br>OR<br>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 |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | 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. |
| **R12** | N/A | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation.<br>OR<br>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. |
| **R13** | 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 areas or portions of whose areas were also included in the same islanding event in one of the manners |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | described in Requirement R13 |
| **R14** | 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 items in Parts 14.1 through 14.3. |

## E. Regional Variances

### E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

**E.A.3**. Each Planning Coordinator shall develop a UFLS program, including 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). *[VRF: High][Time Horizon: Long-term Planning]*

**E.A.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.A.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.A.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

**EA.3.3.1.** Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

**EA.3.3.2.** Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

**EA.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

**E.A.4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

**E.A.4.1** Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1A, and

**E.A.4.2** Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 - Attachment 2A, and

**E.A.4.3** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

**M.E.A.3**. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.

**M.E.A.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.

| E # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| **EA3** | N/A | The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions | The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions | The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions<br>OR<br>The Planning Coordinator failed to develop a UFLS program. |
| **EA4** | N/A | The Planning Coordinator conducted and documented 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 E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3. | The Planning Coordinator conducted and documented 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 E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3. | The Planning Coordinator conducted and documented 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 E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3.<br>OR<br>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 E.A.3 |

## E.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

**E.B.1.** Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

**E.B.2.** Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

**E.B.2.1.** Those islands selected by applying the criteria in Requirement E.B.1, and

**E.B.2.2.** Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

**EB.3.** Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, 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). *[VRF: High][Time Horizon: Long-term Planning]*

**E.B.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.B.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.B.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

**E.B.3.3.1.** Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

**E.B.3.3.2.** Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

**E.B.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

**E.B.4.** Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

**E.B.4.1.** Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

**E.B.4.2.** Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

**E.B.4.3.** Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

**E.B.4.4.** Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

**E.B.4.5.** Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

**E.B.4.6.** Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

**E.B.4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

**E.B.11.** 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 participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

**E.B.11.1.** The performance of the UFLS equipment,

**E.B.11.2** The effectiveness of the UFLS program

**E.B.12.** Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

**M.E.B.1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.

**M.E.B.2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.

**M.E.B.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.

**M.E.B.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.

**M.E.B.11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.

**M.E.B.12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.

| E # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| **E.B.1** | N/A | The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that 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, that may form islands<br><br>OR<br><br>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that 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, that may form islands | The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that 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, that may form islands | The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands |
| **E.B.2** | N/A | N/A | The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2 | The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2<br><br>OR<br><br>The Planning Coordinator failed to identify any island(s) from the |

| E # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | regional review to serve as a basis for designing its UFLS program. |
| **E.B.3** | N/A | The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions | The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions | The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions<br>OR<br>The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area. |
| **E.B.4** | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1 | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1 | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1 | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1 |

| E # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | through E.B.4.7. | through E.B.4.7. | through E.B.4.7. | through E.B.4.7.<br>OR<br>The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 |
| **E.B.11** | The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.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, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.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, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.<br>OR<br>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and | The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation.<br>OR<br>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event |

| E # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
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| | | | documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2. | assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.<br><br>OR<br><br>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2. |
| **E.B.12** | N/A | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation. |

| E # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | OR<br><br>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies |

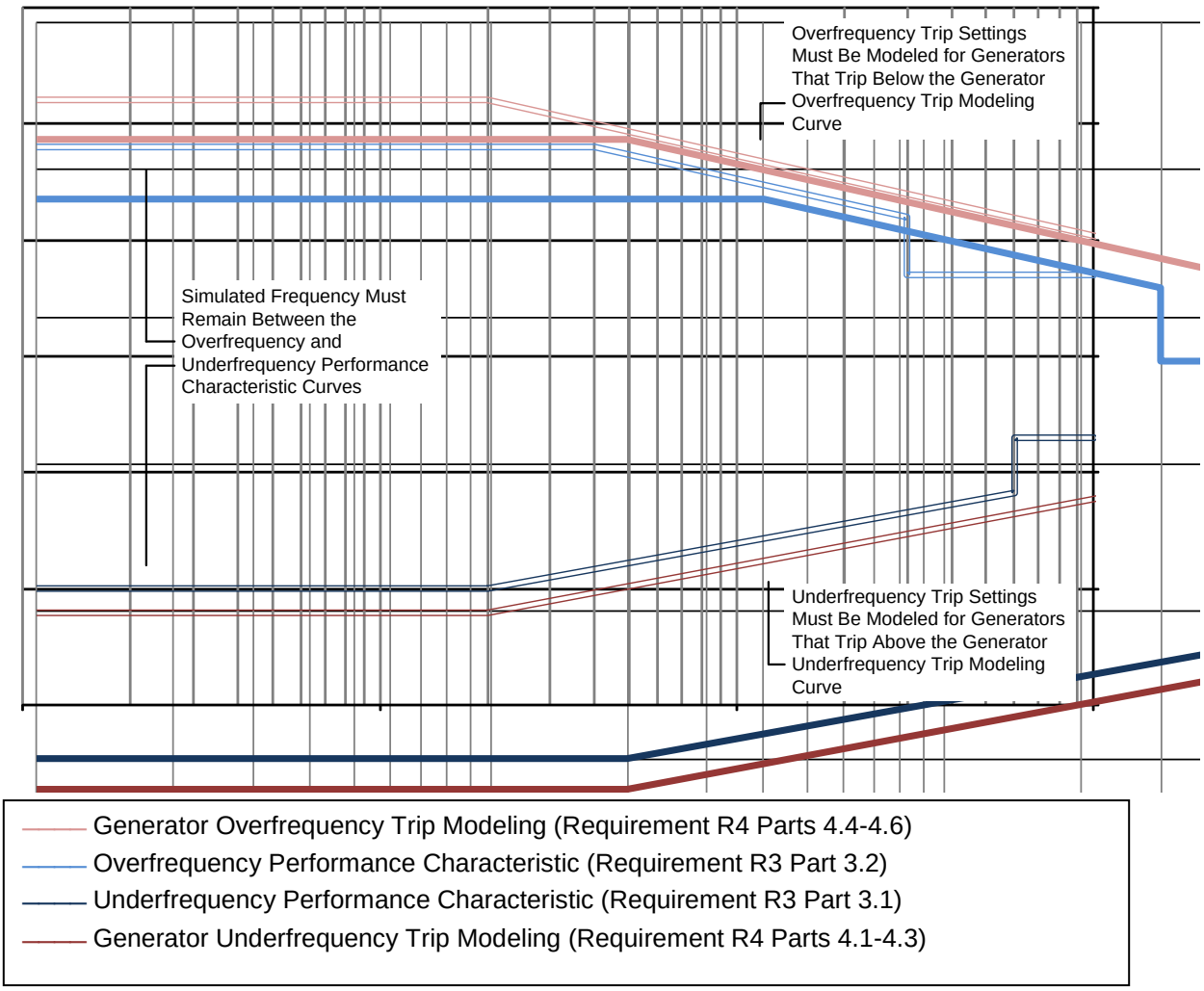
## Associated Documents

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 1 | | Complete revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0 | |
| | | | |

# PRC-006-1 – Attachment 1

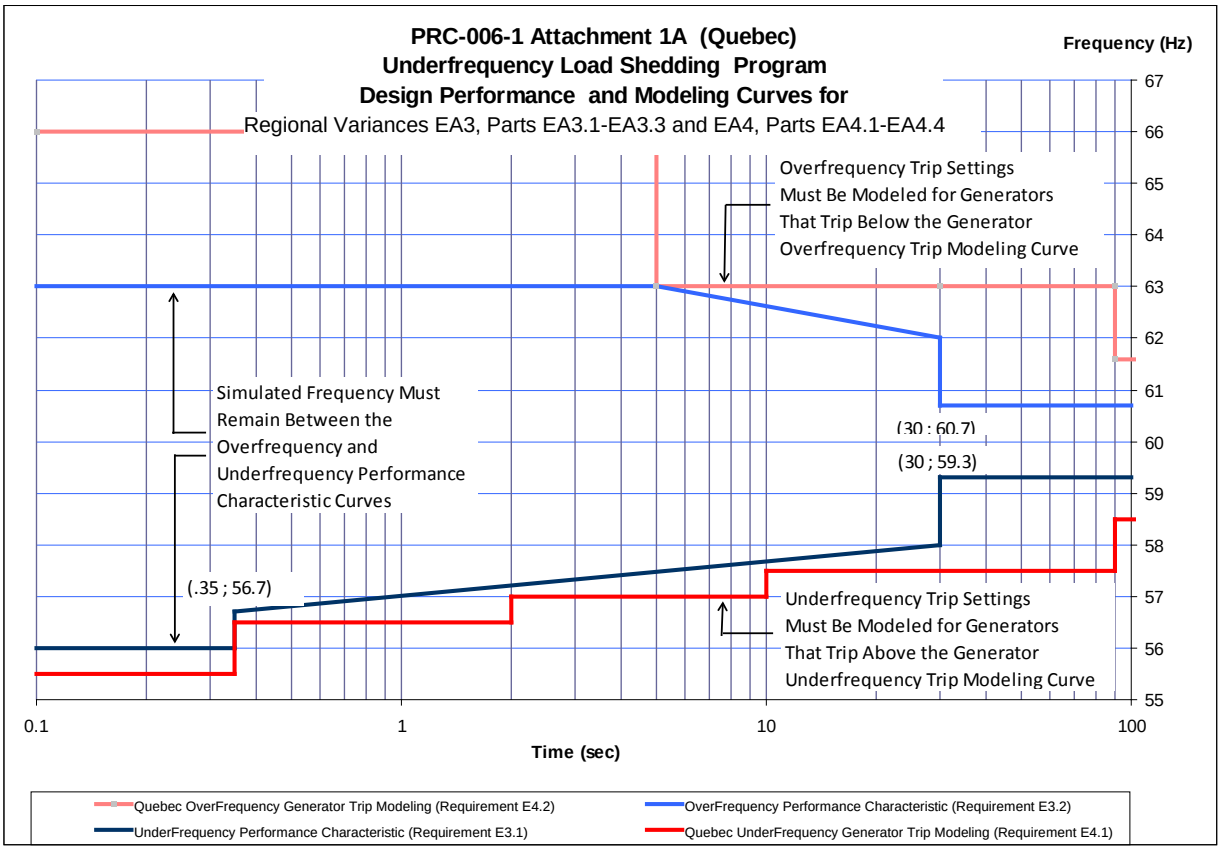
## Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6




### Curve Definitions

| Generator Overfrequency Trip Modeling | | Overfrequency Performance Characteristic | | |
|---|---|---|---|---|
| t ≤ 2 s | t > 2 s | t ≤ 4 s | 4 s < t ≤ 30 s | t > 30 s |
| f = 62.2 Hz | f = -0.686log(t) + 62.41 Hz | f = 61.8 Hz | f = -0.686log(t) + 62.21 Hz | f = 60.7 Hz |

| Generator Underfrequency Trip Modeling | | Underfrequency Performance Characteristic | | |
|---|---|---|---|---|
| t ≤ 2 s | t > 2 s | t ≤ 2 s | 2 s < t ≤ 60 s | t > 60 s |
| f = 57.8 Hz | f = 0.575log(t) + 57.63 Hz | f = 58.0 Hz | f = 0.575log(t) + 57.83 Hz | f = 59.3 Hz |


PRC-006-1 Attachment 1A (Quebec)
Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Regional Variances EA3, Parts EA3.1-EA3.3 and EA4, Parts EA4.1-EA4.4
Frequency (Hz)
67
66
65
64
63
62
61
60
59
58
57
56
55
Overfrequency Trip Settings
Must Be Modeled for Generators
That Trip Below the Generator
Overfrequency Trip Modeling Curve
Simulated Frequency Must
Remain Between the
Overfrequency and
Underfrequency Performance
Characteristic Curves
(30 ; 60.7)
(30 ; 59.3)
(.35 ; 56.7)
Underfrequency Trip Settings
Must Be Modeled for Generators
That Trip Above the Generator
Underfrequency Trip Modeling Curve
0.1
1
10
100
Time (sec)
Quebec OverFrequency Generator Trip Modeling (Requirement E4.2)
OverFrequency Performance Characteristic (Requirement E3.2)
UnderFrequency Performance Characteristic (Requirement E3.1)
Quebec UnderFrequency Generator Trip Modeling (Requirement E4.1)

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Please use this form to submit comments on the first posting of the Regional Reliability Standard **PRC-006-NPCC-1—Automatic Under frequency Load Shedding**. Comments must be submitted by Feb, 24, 2011**.** You may submit the completed form using the electronic comment form posted with the standard. If you have questions please contact **Stephanie Monzon** at Stephanie.Monzon@nerc.net or by telephone at 610-608-8084.

| **Individual Commenter Information**<br><br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
| | ☐ | 2 — RTOs and 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 and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information**

A regional reliability standard shall be: (1) a regional reliability standard that is more stringent than the continent-wide reliability standard, including a regional standard that addresses matters that the continent-wide reliability standard does not; or (2) a regional reliability standard that is necessitated by a physical difference in the bulk power system. Regional reliability standards shall provide for as much uniformity as possible with reliability standards across the interconnected bulk power system of the North American continent. Regional reliability standards, when approved by FERC and applicable authorities in Mexico and Canada shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the applicable area, regardless of membership in the region.

**PRC-006-NPCC-1** ensures the development of an effective automatic under frequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events.

Each NPCC Regional Reliability Standard shall enable or support one or more of the NERC reliability principles, thereby ensuring that each standard serves a purpose in support of the reliability of the regional bulk power system. Each of those standards shall also be consistent with all of the NERC reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence. The NERC reliability principles supported by this standard are the following:

- **Reliability Principle 1** — Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
- **Reliability Principle 2** — The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

The proposed Northeast Power Coordinating Council (NPCC) Regional Reliability Standard is not inconsistent with, or less stringent than established NERC Reliability Standards. Once approved by the appropriate authorities, NPCC Regional Reliability Standard obligates the NPCC to monitor and enforce compliance, apply sanctions, if any, consistent with any regional agreements and the NERC rules.

**PRC-006-NPCC-1** standard applies to each Transmission Owner, Distribution Provider, Generator Owner and Planning Coordinator in the NPCC region. The purpose of this standard is to ensure the development of an effective automatic under frequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events.

The NPCC **PRC-006-NPCC-1** standard contains twenty -six main requirements for applicable entities within the NPCC geographic area. The standard contains the following:

1. Requirement R1 requires that each Planning Coordinator conduct system studies to identify anticipated islands.
2. Requirement R2 requires that each Planning Coordinator provide information on anticipated islands to Transmission Owners, Distribution Providers, and Generator Owners.
3. Requirement R3 requires that each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in Tables 1 through 3.
4. Requirement R4 requires that each Distribution Provider or Transmission Owner that must arm its load to trip on under frequency in order to meet its minimum obligations and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R3 shall provide their Planning Coordinator with the information in parts 4.1 through 4.4.
5. Requirement R5 requires that each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC with peak net Load connected to its Facilities shall ensure that the total nominal operating time includes the under frequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time as specified in parts 5.1 through 5.2.
6. Requirement R6 requires that each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Table 4.
7. Requirement R7 requires that each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC with peak net load connected to its

Facilities shall insure that the total nominal operating time includes the under frequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time.

8. Requirement R8 requires that each Distribution Provider and Transmission Owner set their under frequency relays with a minimum time delay as specified in parts 8.1 and 8.2.

9. Requirement R9 requires that each Planning Coordinator shall develop, implement and maintain a program to establish the appropriate inhibit thresholds to be utilized within its region's UFLS program.

10. Requirement R10 requires that each Planning Coordinator shall provide to Transmission Owners and Distribution Providers within its program area the specific inhibit thresholds applicable to each Transmission Owner or Distribution Providers.

11. Requirement R11 requires that each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R10.

12. Requirement R12 requires that each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator in accordance with R10.

13. Requirement R13 requires that each Transmission Owner and Distribution Provider shall annually provide documentation to its Planning Coordinator of the actual net load that would be shed by the UFLS relays that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.

14. Requirement R14 requires that each Generator Owner shall ensure that their generating units do not trip for under frequency conditions above the appropriate generator under frequency trip protection settings threshold curve in Figure 1.

15. Requirement R15 requires that each Generator Owner shall transmit the generator under frequency trip setting and time constant to its Planning Coordinator within 45 days of the Planning Coordinator’s request.

16. Requirement R16 requires that each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard or an existing generator increasing its net capability by greater than 10% shall design in its in generating unit in accordance with parts 16.1 through 16.3.

17. Requirement R17 requires that each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have under frequency protections set to trip above the curve in Figure 1 shall set its protection, transmit the setting and obtain compensatory load as specified in parts 17.1 through 17.3.

18. Requirement R18 requires that each Planning Coordinator in Ontario, Quebec and the Maritime provinces apply the methodology described in Attachment A to determine the compensatory load shedding that is required in Requirement R17.3.

19. Requirement R19 requires that each Generator Owner, Distribution Provider or Transmission Owner in ISO-NE and the New York ISO apply the methodology described in Attachment B to determine the compensatory load shedding that is required in Requirement R17.3.

20. Requirement R20 requires that each Generator Owner of existing boiling water reactor nuclear generating plants with units that have under frequency relay threshold settings above the Eastern Interconnection generator tripping curve in

Figure 1 shall set their under frequency trip settings, and tolerance settings and transmit the settings as specified in parts 20.1 through 20.3.

21. Requirement R21 requires that each Transmission Owner and Distribution Provider shall annually provide its UFLS program data to its Planning Coordinator in accordance with R22 for inclusion in the Planning Coordinator's data base.
22. Requirement R22 requires that each Planning Coordinator develop, update and maintain its UFLS program data base as specified in parts 22.1 through 22.5.
23. Requirement R23 requires that each Planning Coordinator shall assess that the UFLS program requirements within its Planning Coordinator area are satisfied as implemented by Transmission Owners, Distribution Providers, and Generator Owners
24. Requirement R24 requires that each Planning Coordinator notify its Distribution Providers, Transmission Owners, and Generator Owners of changes to load distribution needed to satisfy UFLS program requirements
25. Requirement R25 requires that each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R24
26. Requirement R26 requires that each Distribution Provider, Transmission Owner and Generator Owner develop and submit an implementation plan within 90 days of the request from the Planning Coordinator in accordance with Requirement R25.

The approval process for a regional reliability standard requires NERC to publicly notice and request comment on the proposed standard. Comments shall be permitted only on the following criteria (technical aspects of the standard are vetted through the regional standards development process):

**Unfair or Closed Process —** The regional reliability standard was not developed in a fair and open process that provided an opportunity for all interested parties to participate. Although a NERC-approved regional reliability standards development procedure shall be presumed to be fair and open, objections could be raised regarding the implementation of the procedure.

**Adverse Reliability or Commercial Impact on Other Interconnections —** The regional reliability standard would have a significant adverse impact on reliability or commerce in other interconnections.

**Deficient Standard —** The regional reliability standard fails to provide a level of reliability of the bulk power system such that the regional reliability standard would be likely to cause a serious and substantial threat to public health, safety, welfare, or national security.

**Adverse Impact on Competitive Markets within the Interconnection —** The regional reliability standard would create a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability.

**You are not required to answer all questions. Enter all comments in simple text format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. **Was the proposed standard developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?**

   ☐ Yes
   ☐ No

   Comments:

2. **Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

   ☐ Yes
   ☐ No

   Comments:

3. **Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?**

   ☐ Yes
   ☐ No

   Comments:

4. **Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

   ☐ Yes
   ☐ No

   Comments:

5. **Does the proposed regional reliability standard meet at least one of the following criteria?**

   - **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
   - **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
   - **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

   ☐ Yes
   ☐ No

   Comments:

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# Consideration of Comments

## NPCC Automatic Underfrequency Load Shedding Program

The NPCC Automatic Underfrequency Load Shedding Drafting Team thanks all commenters who submitted comments on the proposed revisions (clean and redline) to the PRC-006-NPCC-01 standard. These standards were posted for a 30-day public comment period from November 22, 2011 through December 22, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were six sets of comments, including comments from more than 12 different people from approximately nine companies representing five of the 10 Industry Segments as shown in the table on the following pages.

All submitted comments may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/regional_standards/regional_reliability_standards_under_development.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 and director 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 Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

## Index to Questions, Comments, and Responses


**1.** Was the proposed standard developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure? ..... 5

**2.** Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection? ..... 7

**3.** Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security? ..... 15

**4.** Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability? ..... 16

**5.** Does the proposed regional reliability standard meet at least one of the following criteria? ..... 19

**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. | Michael Gildea | Dominion Resources Services, Inc. | MRO | 5 |
| 2. | Louis Slade | Dominion Resources Services, Inc. | SERC | 5 |
| 3. | Connie Lowe | Dominion Resources Services, Inc. | RFC | 5 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2. | Group | Annie Lauterbach | Bonneville Power Administration | X | | X | | X | X | | | | |

| | Additional Member | Additional Organization | Region | Segment Selection |
|---|---|---|---|---|
| 1. | Gregory Vasallo | Customer Service Engineering | WECC | 1 |
| 2. | Laura Oliver | Customer Service Engineering | WECC | 1 |
| 3. | Fred Ojima | Transmission Planning | WECC | 1 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3. | 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 |
| 4. | Individual | Silvia Parada Mitchell | NextEra Energy | X | | X | | X | X | | | | |
| 5. | Individual | Michael Lombardi | Northeast Utilities | X | | X | | X | | | | | |
| 6. | Individual | John Seelke | PSEG Services Corporation | X | | X | | X | X | | | | |

**1.** Was the proposed standard developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?

**Summary Consideration:**

| Organization | Yes or No | Question 1 Comment |
|---|---|---|
| Bonneville Power Administration | | BPA thanks you for the opportunity to comment on PRC-006-NPCC-01, Automatic Underfrequency Load Shedding. BPA has no comments or concerns at this time as this standard is not applicable to BPA. BPA thanks you for the opportunity to comment on PRC-006-NPCC-1. BPA has no comments or concerns at this time as this standard is not applicable to BPA.<br><br>Thank you for your comment. |
| **Response:** | | |
| Independent Electricity System Operator | Yes | |
| Dominion | Yes | |
| Northeast Utilities | Yes | |
| PSEG Services Corporation | No | See answer to Q4 below.<br>Thank you for your comment.<br>See response to Q4 below. |

| Organization | Yes or No | Question 1 Comment |
|---|---|---|
| Next Era Energy | | |

**2.** Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?

**Summary Consideration:**

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| Dominion | Yes | R16.3 and R18 cannot be implemented. As we have stated in previous comments, we do not agree with the obligation for a non-conforming generator to procure a service (i.e., load shed) for which we have found no willing provider. It is Dominion's position that this portion of the regional standard is not feasible, given no entity will provide the service a Generator Owner is obligated to procure, which essentially guarantees that a Generator Owner of a non-conforming generator will not be able to comply with these requirements.<br><br>Thank you for your comment.<br><br>The Regional Standard Drafting Team acknowledges the technical challenges of administering the compensatory load shedding program and as a result has developed requirements stating that all new units shall conform to the generator tripping curve.<br><br>Additionally, to address your concern regarding generators that are already interconnected and in commercial operation, non conforming generators either have existing contracts to provide compensatory load shedding or have mitigated the conditions that would trip the unit above the appropriate generator curve.<br><br>These requirements are contained as criteria within the approved Directory #12 and are currently in effect throughout the NPCC region. |

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| | | Further, as Dominion noted in previous comments, there are technical difficulties associated with R16.3 and R18 which would likely have an adverse impact on reliability. Specifically, shedding additional load equivalent to a non-coordinating generator would be extremely difficult to design and coordinate. The design would have to account for the real-time status and output of the generator. Otherwise, this requirement could create more problems than it attempts to solve. For example, consider a load shed program that is designed assuming the need to shed load equivalent to rated capacity for a non-coordinating generator and a frequency event occurs when this generator is off line. The program sees the frequency at the trigger level and sheds the load equivalent to the non-coordinating generator. However, since that generator wasn't actually on line, there is no additional loss of generation, but the MW load equivalent of the generator (that is not designed into the UFLS scheme) is lost anyway. If the UFLS program then implements the next level of designed reduction of load, this may result in a subsequent rebound in frequency. This may very well result in overshoot that is more than designed for, resulting in generator trip from over-frequency. Obviously, the more non-coordinating generators there are, the more difficult the task of coordination with UFLS schemes becomes and the more widespread the effects on customers.<br><br>The Regional Standard Drafting Team acknowledges the technical challenges of administering the compensatory load shedding program and as a result has |

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| | | developed requirements stating that all new units shall conform to the generator tripping curve.<br><br>With respect to the possibility of over shedding of load due to existing compensatory load shedding not matching generation on line, the concern is acknowledged.<br><br>However, an average MW output was intended to align the amount of compensatory load shedding provided with the unit output most likely to be lost if the unit tripped.<br><br>It is impossible to ensure a close match between compensatory load shedding and unit output without real-time arming of UFLS. Adding precision to the amount of compensatory load shedding that is required will not improve the viability of the program.<br><br>NERC Standard PRC-006-1, Automatic Underfrequency Load Shedding, has been filed with FERC and a Notice of Potential Rulemaking has been issued for industry comment (RM11-18). Additionally, under NERC Project 2007-09 Generator Verification, draft Standard PRC-024-1, Generator Frequency and Voltage Protective Relay Setting, has the potential to impact the NPCC Regional Standard as it works through the NERC and FERC approval process. Given the uncertainty of outcome, there is a potential impact associated with implementation of the Regional Standard absent FERC approved National Standards. According to the NERC Rules of Procedure, Section 302 establishes "essential attributes for technically excellent reliability standards." Item #9 addresses practicality and states the following:"Each reliability standard shall establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter."Dominion believes the issues previously noted result in a regional standard that cannot be "practically implemented by the assigned responsibility entities."The NPCC Regional Standards Development Procedure in Section II establishes that "in order to receive the approval of the ERO, the NPCC Reliability |

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| | | Standards Development Process must also achieve the following objectives." Specifically:" o No Adverse Impact on Reliability of the Interconnection -An NPCC Regional Reliability Standard provides a level of bulk power system reliability that is necessary and adequate to protect public health, safety, welfare, and North American security and will not have an adverse impact on the reliability of the Interconnection or other Regions within the Interconnection."Dominion believes that the technical difficulties associated with implementing compensating load shedding, if such a service were available, for non-conforming generators may "have an adverse impact on the reliability of the Interconnection or other Regions within the Interconnection."Therefore, Dominion believes the aforementioned issues must be resolved prior to approval of this Regional Reliability Standard by NERC and FERC.<br><br>The Regional Standard Drafting Team acknowledges the technical challenges of administering the compensatory load shedding program and as a result has developed requirements stating that all new units shall conform to the generator tripping curve.<br><br>Additionally, to address your concern regarding generators that are already interconnected and in commercial operation, non conforming generators either have existing contracts to provide compensatory load shedding or have mitigated the conditions that would trip the unit above the appropriate generator curve.<br><br>PRC -006-NPCC -1 was developed in response to a request from the ERO to satisfy FERC Order 693. At that time, 24 standards were identified as 'fill in the blank' and as a result the ERO was ordered to modify the individual standards reliance on the Regional Reliability Organization.<br><br>Additionally, of those 24 standards 4 were identified by the ERO and the regions to be regionally specific enough to warrant the development of a regional standard and UFLS is one of those 4 standards. |

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| | | The Drafting Team made a continual effort to coordinate the standards development with other related standards that were being drafted concurrently. |
| **Response:** | | |
| Next Era Energy | Yes | No. R16 requires generators that cannot meet the UFLS curve to have compensatory load shedding provided by a Distribution Provider (DP). This requirement is fatal flawed, because this regional reliability standard has inappropriately moved from the regional reliability organization (RRO) implementing the standard to planning coordinators, distribution providers, generator owners and transmission owners. The need for load shedding is not a bottom up analysis. Instead, the need for load shedding is more appropriately decided collectively by Transmission Planners, Transmission Operators, Reliability Coordinators and Planning Coordinators. Thus, the requirement effectively decentralizes the UFLS response, which will only serve to make the system less reliable.<br><br>Thank you for your comment.<br><br>The Regional Standard Drafting Team acknowledges the technical challenges of administering the compensatory load shedding program and as a result has developed requirements stating that all new units shall conform to the generator tripping curve.<br><br>Additionally, PRC -006-NPCC -1 was developed in response to a request from the ERO to satisfy FERC Order 693.<br><br>At that time, 24 standards were identified as 'fill in the blank' and as a result the ERO was ordered to modify the individual standards reliance on the Regional Reliability Organization. |
| **Response:** | | |
| PSEG Services Corporation | Yes | First, the standard lacks the requirement for coordination between Planning Coordinators (PCs) who have a part of one PC's island within another PC's region (R5 |

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| | | in NERC PRC-006-1). UFLS program design may require coordination across regional boundaries as addressed in the NERC standard. R1 in the NPCC standard is NPCC-centric, whereas the power system is not: "Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS)."<br><br>Thank you for your comment.<br><br>The Drafting Team made a continual effort to coordinate the standards development with other related standards that were being drafted concurrently.<br><br>Accordingly, Requirement R1 in NERC Standard PRC -006-1 requires a PC to consider interconnected portions of the BES in adjacent PC areas and Regional Entity areas that may form islands.<br><br>Therefore the requirement to coordinate with adjacent Regional Entities was not drafted into the NPCC Regional Standard since it is already contained in PRC -006-01.<br><br>In addition, R1 is both mistaken and misleading in its reference to the NERC PRC Standard on UFLS: first, the NERC standard does not address compensatory load shedding.<br><br>The purpose of requirement R1 in the Regional Standard PRC -006-NPCC -1 is to provide the more specific requirements for utilizing the islands that have been identified in the NERC Standard.<br><br>Accordingly, Generator Owners that trip above the curve in Figure 1 must arrange for compensatory load shedding as identified by the PC to ensure that adequate |

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| | | compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.<br><br>Second, the NERC standard R1 requires PCs "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." While both the NPCC and the NERC standards require PCs to develop UFLS criteria, the NERC standard is more expansive in its inclusion of "adjacent Planning Coordinator areas and Regional Entity areas." Of course, a regional standard cannot require coordination with a PC in another region. The NERC standard is superior in that regard, and therefore the NPCC standard, which lacks this requirement, would be a detriment to reliability.<br><br>With regard to coordination between the NERC standard and the NPCC Regional Standard, in this case the NERC Standard establishes the broad requirement to identify islands.<br>The NPCC Regional Standard establishes the requirements for entities who must utilize these islands in order to develop a UFLS program.<br><br>Second, UFLS programs need to be developed on an Interconnection-wide basis, not a regional basis. Frequency is an interconnection-specific parameter. This is recognized in the draft NERC standard BAL-003-1 - Frequency Response and Frequency Bias Setting, where all Balancing Authorities within an Interconnection must have a portion of the required Interconnection frequency response. |

| Organization | Yes or No | Question 2 Comment |
|---|---|---|
| | | PRC -006-NPCC -1 was developed in response to a request from the ERO to satisfy FERC Order 693. At that time, 24 standards were identified as 'fill in the blank' and as a result the ERO was ordered to modify the individual standards reliance on the Regional Reliability Organization.<br><br>Additionally, of those 24 standards 4 were identified by the ERO and the regions to be regionally specific enough to warrant the development of a regional standard and UFLS is one of those 4 standards. |
| **Response:** | | |
| Independent Electricity System Operator | No | |
| Northeast Utilities | No | |

**3.** Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?

**Summary Consideration:**

| Organization | Yes or No | Question 3 Comment |
|---|---|---|
| Dominion | No | None that can be determined by Dominion.<br>Thank you for your comment. |
| **Response:** | | |
| Independent Electricity System Operator | No | |
| Northeast Utilities | No | |
| PSEG Services Corporation | No | |
| Bonneville Power Administration | | |
| NextEra Energy | | |

**4.** Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?

**Summary Consideration:**

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| Dominion | Yes | See response provided to Question #2.<br>Thank you for the comment. |
| **Response:** | | |
| PSEG Services Corporation | Yes | NERC's PRC-006-1 does not contain a specific generator performance requirement. Generators that cannot meet the underfrequency operational assumption in Attachment 1 of the standard are modeled "as is" by the Planning Coordinator in accordance with R4, and the UFLS calculated with their actual underfrequency generator performance parameters must be provided by UFLS entities (Transmission Owners and Distribution Providers). However, NPCC's draft standard proposes specific generator performance requirements on existing in NYISO and ISO-NE -see Attachment B referenced in R18. In addition, it would require existing Generator Owner's to obtain compensatory UFLS for the early tripping of their generator's which cannot meet their specific performance requirements - see R16.3. This compensatory UFLS would be provided by Transmission Owners or Distribution Providers, but the Generator Owner would be required to obtain it. Although not directly stated in this regional standard, the presumption is that Generator Owners would be required to compensate their providers for their compensatory UFLSPSEG objects to this aspect (compensatory UFLS) of the draft regional standard for several |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| | | reasons. First, the added cost to existing Generation Owners whose generators do not meet the draft standard's performance requirements will impact the competitiveness of these generators since they must bear an added cost of acquiring compensatory UFLS that other generators will not. This violates the NPCC Regional Standards Development Procedure, which adheres to NERC's market principles - see p. 9 of the procedure. The NERC market principles state, in part, that "A reliability standard shall not give any market participant an unfair competitive advantage."<br><br>Thank you for the comment.<br><br>In accordance with NERC requirements and NPCC criteria an assessment of the NPCC UFLS program attributes is required to be performed by NPCC technical committees.<br><br>Careful coordination of UFLS parameters is necessary to meet the performance requirements of the program and generator performance during frequency excursion is essential to maintaining the programs adequacy.<br><br>Second, the requirement that existing Generator Owners acquire compensatory UFLS to make up for their generators underfrequency performance is completely absent in the Reliability Functional model description of a Generator Owner's functions. By contrast, a Distribution Provider is assigned the task of "providing] and implement[ing] load-shed capability," a result that makes sense since Distribution Providers.<br><br>The Regional Standard Drafting Team acknowledges the technical challenges of administering the compensatory load shedding program and as a result has developed requirements stating that all new units shall conform to the generator tripping curve.<br><br>Non conforming generators that are already interconnected and in commercial operation, either have existing contracts to provide compensatory load shedding or have mitigated the conditions that would trip the unit above the appropriate |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| | | generator curve.<br><br>With regard to the concern regarding the functional model responsibilities, existing arrangements to provide compensatory load shedding are acceptable to meet the standards requirements and no new generation shall be permitted to arrange such agreements in lieu of adhering to the UFLS program parameters. |
| **Response:** | | |
| Northeast Utilities | No | |
| Independent Electricity System Operator | No | |
| Bonneville Power Administration | | |
| NextEra Energy | | |

**5.** Does the proposed regional reliability standard meet at least one of the following criteria?

- The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard
- The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard
- The proposed regional difference is necessitated by a physical difference in the bulk power system.

**Summary Consideration:**

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| Dominion | Yes | NERC Standard PRC-006-1, Automatic Underfrequency Load Shedding, has been filed with FERC and a Notice of Potential Rulemaking has been issued for industry comment (RM11-18). Additionally, under NERC Project 2007-09 Generator Verification, draft Standard PRC-024-1, Generator Frequency and Voltage Protective Relay Setting, has the potential to impact the NPCC Regional Standard as it works through the NERC and FERC approval process. Given the uncertainty of outcome, there is a potential impact associated with implementation of the Regional Standard absent FERC approved National Standards.<br>Thank you for the comment.<br>PRC -006-NPCC -1 was developed in response to a request from the ERO to satisfy FERC Order 693. At that time, 24 standards were identified as 'fill in the blank' and as a result the ERO was ordered to modify the individual standards reliance on the Regional Reliability Organization.<br>The Drafting Team made a continual effort to coordinate the standards development with other related standards that were being drafted concurrently. |
| **Response:** | | |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| PSEG Services Corporation | Yes | While there are more specific criteria and more requirements, the standard has the deficiencies cited in Q2 and Q4 above.<br>Thank you for the comment.<br>Please see responses to Q2 and Q4 above.<br>ADDITIONAL COMMENTS not addressed in any prior questions: The standard may violate the market principle that states "Standards shall not define an adequate amount of, or require expansion of, bulk power system resources or delivery capability." Delivery capability of a generator includes the frequency range over which it can safely and reliably produce MVA output. As written the standard defines adequacy of delivery capability and also would require Generator Owners of units that cannot meet that adequacy requirement to either increase their generators' underfrequency response capability or acquire compensatory UFLS, presumably at their cost. This violates the market principle.<br>Thank you for the comment.<br>In accordance with NERC requirements and NPCC criteria an assessment of the NPCC UFLS program attributes is required to be performed by NPCC technical committees.<br>Careful coordination of UFLS parameters is necessary to meet the performance requirements of the program and generator performance during frequency excursion is essential to maintaining the programs adequacy. |
| **Response:** | | |
| Independent Electricity | Yes | |

| Organization | Yes or No | Question 4 Comment |
|---|---|---|
| System Operator | | |
| Northeast Utilities | Yes | |
| Bonneville Power Administration | | |
| NextEra Energy | | |

END OF REPORT

**Individual or group. (6 Responses)**
**Name (3 Responses)**
**Organization (3 Responses)**
**Group Name (3 Responses)**
**Lead Contact (3 Responses)**
**Question 1 (4 Responses)**
**Question 1 Comments (6 Responses)**
**Question 2 (5 Responses)**
**Question 2 Comments (6 Responses)**
**Question 3 (4 Responses)**
**Question 3 Comments (6 Responses)**
**Question 4 (4 Responses)**
**Question 4 Comments (6 Responses)**
**Question 5 (4 Responses)**
**Question 5 Comments (6 Responses)**

| |
|---|
| - |
| Individual |
| Michael Falvo |
| Independent Electricity System Operator |
| Yes |
| |
| No |
| |
| No |
| |
| No |
| |
| Yes |
| |
| Group |
| Compliance & Responsibility |
| Silvia Parada Mitchell |
| |
| Yes |
| No. R16 requires generators that cannot meet the UFLS curve to have compensatory load shedding provided by a Distribution Provider (DP). This requirement is fatal flawed, because this regional reliability standard has inappropriately moved from the regional reliability organization (RRO) implementing the standard to planning coordinators, distribution providers, generator owners and transmission owners. The need for load shedding is not a bottom up analysis. Instead, the need for load shedding is more appropriately decided collectively by Transmission Planners, Transmission Operators, Reliability Coordinators and Planning Coordinators. Thus, the requirement effectively decentralizes the UFLS response, which will only serve to make the system less reliable. |
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| |
| |
| Individual |
| Michael Lombardi |
| Northeast Utilities |
| Yes |
| |
| No |
| |
| No |
| |

| |
|---|
| No |
| |
| Yes |
| |
| Group |
| Dominion |
| Mike Garton |
| Yes |
| |
| Yes |
| R16.3 and R18 cannot be implemented. As we have stated in previous comments, we do not agree with the obligation for a non-conforming generator to procure a service (i.e., load shed) for which we have found no willing provider. It is Dominion's position that this portion of the regional standard is not feasible, given no entity will provide the service a Generator Owner is obligated to procure, which essentially guarantees that a Generator Owner of a non-conforming generator will not be able to comply with these requirements. Further, as Dominion noted in previous comments, there are technical difficulties associated with R16.3 and R18 which would likely have an adverse impact on reliability. Specifically, shedding additional load equivalent to a non-coordinating generator would be extremely difficult to design and coordinate. The design would have to account for the real-time status and output of the generator. Otherwise, this requirement could create more problems than it attempts to solve. For example, consider a load shed program that is designed assuming the need to shed load equivalent to rated capacity for a non-coordinating generator and a frequency event occurs when this generator is off line. The program sees the frequency at the trigger level and sheds the load equivalent to the non-coordinating generator. However, since that generator wasn't actually on line, there is no additional loss of generation, but the MW load equivalent of the generator (that is not designed into the UFLS scheme) is lost anyway. If the UFLS program then implements the next level of designed reduction of load, this may result in a subsequent rebound in frequency. This may very well result in overshoot that is more than designed for, resulting in generator trip from over-frequency. Obviously, the more non-coordinating generators there are, the more difficult the task of coordination with UFLS schemes becomes and the more widespread the effects on customers. NERC Standard PRC-006-1, Automatic Underfrequency Load Shedding, has been filed with FERC and a Notice of Potential Rulemaking has been issued for industry comment (RM11-18). Additionally, under NERC Project 2007-09 Generator Verification, draft Standard PRC-024-1, Generator Frequency and Voltage Protective Relay Setting, has the potential to impact the NPCC Regional Standard as it works through the NERC and FERC approval process. Given the uncertainty of outcome, there is a potential impact associated with implementation of the Regional Standard absent FERC approved National Standards. According to the NERC Rules of Procedure, Section 302 establishes "essential attributes for technically excellent reliability standards." Item #9 addresses practicality and states the following: "Each reliability standard shall establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter." Dominion believes the issues previously noted result in a regional standard that cannot be "practically implemented by the assigned responsibility entities." The NPCC Regional Standards Development Procedure in Section II establishes that "in order to receive the approval of the ERO, the NPCC Reliability Standards Development Process must also achieve the following objectives." Specifically: "• No Adverse Impact on Reliability of the Interconnection —An NPCC Regional Reliability Standard provides a level of bulk power system reliability that is necessary and adequate to protect public health, safety, welfare, and North American security and will not have an adverse impact on the reliability of the Interconnection or other Regions within the Interconnection." Dominion believes that the technical difficulties associated with implementing compensating load shedding, if such a service were available, for non-conforming generators may "have an adverse impact on the reliability of the Interconnection or other Regions within the Interconnection." Therefore, Dominion believes the aforementioned issues must be resolved prior to approval of this Regional Reliability Standard by NERC and FERC. |
| No |
| None that can be determined by Dominion. |
| Yes |
| See response provided to Question #2. |
| Yes |
| NERC Standard PRC-006-1, Automatic Underfrequency Load Shedding, has been filed with FERC and a Notice of Potential Rulemaking has been issued for industry comment (RM11-18). Additionally, under NERC Project 2007-09 Generator Verification, draft Standard PRC-024-1, Generator Frequency and Voltage Protective Relay Setting, has the potential to impact the NPCC Regional Standard as it works through the NERC and FERC approval process. Given the uncertainty of outcome, there is a potential impact associated with implementation of the Regional Standard absent FERC approved National Standards. |
| Individual |
| John Seelke |
| PSEG Services Corporation |

No

See answer to Q4 below.

Yes

First, the standard lacks the requirement for coordination between Planning Coordinators (PCs) who have a part of one PC's island within another PC's region (R5 in NERC PRC-006-1). UFLS program design may require coordination across regional boundaries as addressed in the NERC standard. R1 in the NPCC standard is NPCC-centric, whereas the power system is not: "Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS)." In addition, R1 is both mistaken and misleading in its reference to the NERC PRC Standard on UFLS: first, the NERC standard does not address compensatory load shedding. Second, the NERC standard R1 requires PCs "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." While both the NPCC and the NERC standards require PCs to develop UFLS criteria, the NERC standard is more expansive in its inclusion of "adjacent Planning Coordinator areas and Regional Entity areas." Of course, a regional standard cannot require coordination with a PC in another region. The NERC standard is superior in that regard, and therefore the NPCC standard, which lacks this requirement, would be a detriment to reliability. Second, UFLS programs need to be developed on an Interconnection-wide basis, not a regional basis. Frequency is an interconnection-specific parameter. This is recognized in the draft NERC standard BAL-003-1 – Frequency Response and Frequency Bias Setting, where all Balancing Authorities within an Interconnection must have a portion of the required Interconnection frequency response.

No

Yes

NERC's PRC-006-1 does not contain a specific generator performance requirement. Generators that cannot meet the underfrequency operational assumption in Attachment 1 of the standard are modeled "as is" by the Planning Coordinator in accordance with R4, and the UFLS calculated with their actual underfrequency generator performance parameters must be provided by UFLS entities (Transmission Owners and Distribution Providers). However, NPCC's draft standard proposes specific generator performance requirements on existing in NYISO and ISO-NE –see Attachment B referenced in R18. In addition, it would require existing Generator Owner's to obtain compensatory UFLS for the early tripping of their generator's which cannot meet their specific performance requirements – see R16.3. This compensatory UFLS would be provided by Transmission Owners or Distribution Providers, but the Generator Owner would be required to obtain it. Although not directly stated in this regional standard, the presumption is that Generator Owners would be required to compensate their providers for their compensatory UFLS PSEG objects to this aspect (compensatory UFLS) of the draft regional standard for several reasons. First, the added cost to existing Generation Owners whose generators do not meet the draft standard's performance requirements will impact the competitiveness of these generators since they must bear an added cost of acquiring compensatory UFLS that other generators will not. This violates the NPCC Regional Standards Development Procedure, which adheres to NERC's market principles – see p. 9 of the procedure. The NERC market principles state, in part, that "A reliability standard shall not give any market participant an unfair competitive advantage." Second, the requirement that existing Generator Owners acquire compensatory UFLS to make up for their generators underfrequency performance is completely absent in the Reliability Functional model description of a Generator Owner's functions. By contrast, a Distribution Provider is assigned the task of "provid[ing] and implement[ing] load-shed capability," a result that makes sense since Distribution Providers.

Yes

While there are more specific criteria and more requirements, the standard has the deficiencies cited in Q2 and Q4 above. ADDITIONAL COMMENTS not addressed in any prior questions: The standard may violate the market principle that states "Standards shall not define an adequate amount of, or require expansion of, bulk power system resources or delivery capability." Delivery capability of a generator includes the frequency range over which it can safely and reliably produce MVA output. As written the standard defines adequacy of delivery capability and also would require Generator Owners of units that cannot meet that adequacy requirement to either increase their generators' underfrequency response capability or acquire compensatory UFLS, presumably at their cost. This violates the market principle.

Group

Bonneville Power Administration

Annie Lauterbach

BPA thanks you for the opportunity to comment on PRC-006-NPCC-01, Automatic Underfrequency Load Shedding. BPA has no comments or concerns at this time as this standard is not applicable to BPA. BPA thanks you for the opprotunity to comment on PRC-006-NPCC-1. BPA has no comments or concerns at this time as this standard is not applicable to BPA.

| |
|---|
| |

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

# PRC-006-NPCC-1 Automatic Underfrequency Load Shedding

# Implementation Plan

**Background:**

The purpose of this draft Regional Standard is to ensure the development and maintenance of an effective and coordinated Automatic Underfrequency Load Shedding program in order to preserve the reliability and integrity of the bulk power system during declining system frequency events.

In the developing the Implementation Plan for PRC-006-NPCC-01 the Standard Drafting Team considered the following:

1. The requirements listed in this Regional Standard are intended to cover all aspects of the UFLS program. The Regional Standard Drafting Team (RSDT) coordinated its development with the draft NERC UFLS Standard PRC-006. The intent of this Regional Standard is to be more stringent than the continent wide standard while incorporating specific program characteristics into the requirements.
2. The Implementation Plan for 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.

**Effective Dates:**

Eastern Interconnection & Québec Interconnection Portions of NPCC Excluding the Independent Electricity System Operator (IESO) Planning Coordinator Area of NPCC in Ontario, Canada.

**1**. The effective date for requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than Jan 1, 2016 to allow for the existing implementation plan to be completed.

**2.** The effective date for requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

Independent Electricity System Operator (IESO) Planning Coordinator's Area of NPCC in Ontario, Canada

1. Effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

**References:**

- 2006 Assessment of UFLS Adequacy Part 3 Assessment of Program Modifications.
- SS38 Underfrequency Load Shedding Support Studies

**NPCC Criteria:**

- Directory #12 Underfrequency Load Shedding Program Requirements.
- A-7 NPCC Glossary of Terms.

## 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. NPCC Regional Standards Committee (RSC) authorized posting UFLS RSAR development on August 20, 2008.
2. UFLS RSAR posted on NPCC website on August 25, 2008.
3. NPCC Reliability Coordinating Committee (RCC) approved the Task Force on System Studies (TFSS) as the lead task force to initiate drafting a UFLS Regional Standards on September 4, 2008.
4. NPCC UFLS Regional Standard Drafting Team initial meeting on January 27, 2009.
5. First draft posted on the NPCC Website July 13, 2009 for a 45 day comment period.
6. Second draft posted on the NPCC Website May 26, 2010 for a 45 day comment period.
7. Third draft posted on the NPCC Website May 6, 2011 for a 45 day comment period.

**Description of Current Draft:**

This is the third draft of the proposed standard.

**Future Development Plan:**

| Anticipated Action | Anticipated Date |
|---|---|
| 1. Post the initial draft of the standard for 45 day comment period. | July 13, 2009 to August 27, 2009 |
| 2. Respond to comments on the first posting and post revised standard and implementation plan for a 45 day comment period. | September 2009 to May 2010<br><br>May 26, 2010 to July 9th, 2010 |
| 3. Respond to comments on the 2nd posting. | July 2010 to October 2010 |
| 4. Obtain RSC approval to move the standard forward to balloting. | November 2010 |
| 5. Post the standard and implementation plan for a 30 day pre ballot review. | December 2010 |

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| 6. Conduct a ten day ballot. | December 2010 |
| 7. Respond to ballot comments and post revised standard and implementation plan for a 45 day comment period. | May, 2011. |
| 8. Respond to comments on the 3rd posting. | July 2011 |
| 9. Obtain RSC approval to move the standard forward to balloting. | August 2011 |
| 10. Post the standard and implementation plan for a 30 day pre ballot review. | August 2011 |
| 11. Conduct a ten day ballot. | September 2011 |
| 12. Membership Approval. | September 2011. |
| | |
| | |

## 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 NERC 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 NPCC Glossary.*

*In the standards, defined terms are indicated with its first letter capitalized.*

## A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**
2. **Number:** PRC-006-NPCC-1
3. **Purpose:** To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.
4. **Applicability:**
   - **4.1.** Generator Owner
   - **4.2.** Planning Coordinator
   - **4.3.** Distribution Provider
   - **4.4.** Transmission Owner
5. **(Proposed) Effective Date:** To be established.

## B. Requirements

**R1** Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS). [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R2** Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3** Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1. [Violation Risk Factor: Low] [Time Horizon: Long Term Planning]

**R4** Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R5** Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in UFLS Attachment C, Table 1 if applicable and

5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.

5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.4 Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.

**R6** Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R7** Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay:

7.1 Eastern Interconnection – 100 ms

7.2 Québec Interconnection – 200 ms

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R8** Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R9** Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

**R10** Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

**R11** Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

**R12** Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

**R13** Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R14** Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

**R15** Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

15.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1.

**R16** Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

**R17** Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R18** Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**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 and licensing limitations but not greater than 57.8Hz.

19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 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.

**R20** The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.

20.2 The buses at which the Load is modeled in the NPCC library power flow case.

20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.

20.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.

20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

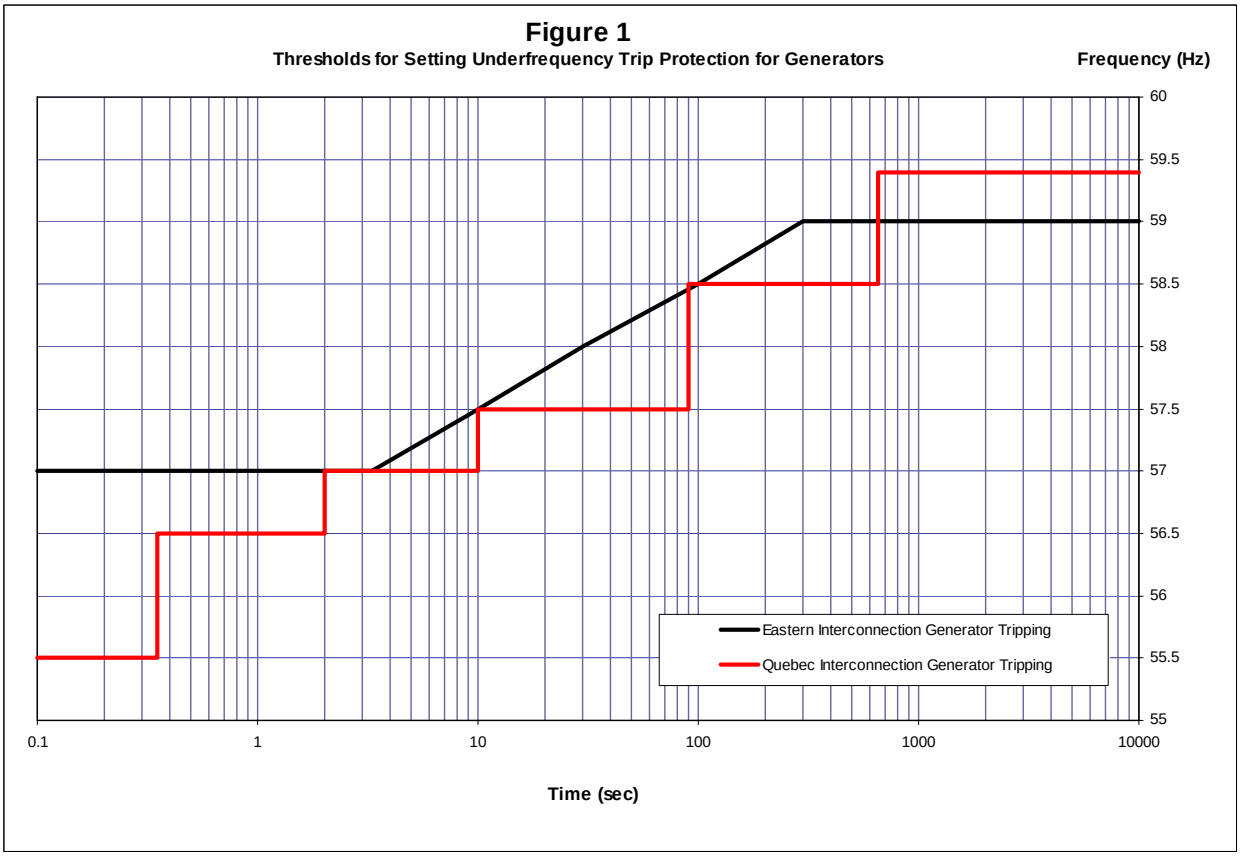
**R21** Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R22** Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

**R23** Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

**Figure 1**

**Thresholds for Setting Underfrequency Trip Protection for Generators**



## C. Measures

**M1** Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

**M2.** Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

**M3** Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

**M4** Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (Attachment C Tables 1-3).

**M5** Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

**M6** Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (Attachment C Table 4).

**M7** Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.

**M8** Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

**M9** Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

**M10** Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.

**M11** Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.

**M12** Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.

**M13** Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.

**M14** Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.

**M15** Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.

**M16** Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.

**M17** Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R17.

**M18** Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R18.

**M19** Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

**M20** Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

**M21** Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

**M22** Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

**M23** Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement 23.

## 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 Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,10, 11, and 12.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 8, 9, 20, and 21.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 18, 22, and 23.

The Generator Owner shall keep evidence for three calendar years for Measures 13, 14, 15, 16, and 19.

### 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

| Requirement | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| **R1** | N/A | **N/A** | Planning Coordinator did not establish requirements for entities aggregating their UFLS programs.<br>or<br>Did not establish requirements for compensatory load shedding. | Planning Coordinator did not establish requirements for entities aggregating their UFLS programs and did not establish requirements for compensatory load shedding. |
| **R2** | The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies. | The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies. | The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies. | The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 60 days after completion of the system studies.<br>or<br>The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program. |
| **R3** | The Planning Coordinator provided the requested information, but did so more than 30 days but less than 41 days to the requesting entity. | The Planning Coordinator provided the requested information, but did so more than 40 days but less than 51 days to the requesting entity. | The Planning Coordinator provided the requested information, but did so more than 50 days but less than 61 days to the requesting entity. | The Planning Coordinator provided the requested information, but did so more than 60 days after the request.<br>or<br>The Planning Coordinator failed to provide the requested information. |

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| **R4** | N/A | N/A | N/A | The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables. |
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| **R5** | N/A | The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table | The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or | The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load. |

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| | | 2 only, the need to deviate from providing two stages of UFLS. | Transmission Owner to comply with the appropriate table. | |
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| **R6** | N/A | N/A | T | The Distribution Provider or Transmission Owner in the Québec Interconnection portion of NPCC did not implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or did not collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. |
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| **R7** | N/A | N/A | N/A | The Distribution Provider or Transmission Owner failed to set |

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| | | | | an underfrequency relay that is part of its region's UFLS program as specified in Requirement R7. |
| **R8** | | N/A | The Planning Coordinator developed inhibit thresholds as specified in Requirement R8 but did not perform the review once per calendar year. | The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R8. |
| **R9** | The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds. | The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds. | The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds. | The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds.<br>or<br>The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds. |
| **R10** | N/A | N/A | N/A | The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with Requirement R9. |

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| **R11** | The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator. | The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator. | The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator. | The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator.<br>or<br>The Distribution Provider or Transmission Owner did not develop its implementation plan. |
| **R12** | | | | The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year. |
| **R13** | N/A | N/A | N/A | The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted. |

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| **R14** | The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator's request. | The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator's request. | The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator's request. | The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75days after the Planning Coordinator's request.<br>or<br>The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator. |
| **R15** | N/A | N/A | The Generator Owner did not fulfill the obligation of Requirement R15; Part 15.1 OR did not fulfill the obligation of Requirement R15, Part 15.2. | The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1 and did not fulfill the obligation of Requirement R15, Part 15.2. |
| **R16** | N/A | The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.2. | The Generator Owner did not fulfill the obligation of Requirement R16; Part 16.1 OR did not fulfill the obligation of Requirement R16, Part 16.3. | The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.1 and did not fulfill the obligation of Requirement R16, Part 16.3. |

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| **R17** | N/A | N/A | N/A | The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required. |
| **R18** | N/A | N/A | N/A | The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required. |
| **R19** | N/A | The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.3. | The Generator Owner did not fulfill the obligation of Requirement R19; Part 19.1 OR did not fulfill the obligation of Requirement R19, Part 19.2. | The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.1 and did not fulfill the obligation of Requirement R19, Part 19.2. |
| | | | | |
| **R20** | The Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5. | The Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5. | The Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5. | The Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5. |

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| **R21** | N/A | N/A | N/A | The Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements. |
| **R22** | N/A | N/A | N/A | The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator. |
| **R23** | The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator. | The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator. | The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator. | The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator.<br>or<br>The Distribution Provider. Transmission Owner or Generator Owner did not develop its implementation plan. |

## PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements:

1. The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate, as identified in Requirement R1

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.

    2.2 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4..

    2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest

frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

## PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has underfrequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

## PRC-006-NPCC-1 Attachment C

**UFLS Table 1: Eastern Interconnection**

Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

| Frequency Threshold (Hz) | Total Nominal Operating Time (s)[1] | Load Shed at Stage as % of TO or DP Load | Cumulative Load Shed as % of TO or DP Load |
|---|---|---|---|
| 59.5 | 0.30 | 6.5 – 7.5 | 6.5 – 7.5 |
| 59.3 | 0.30 | 6.5 – 7.5 | 13.5 – 14.5 |
| 59.1 | 0.30 | 6.5 – 7.5 | 20.5 – 21.5 |
| 58.9 | 0.30 | 6.5 – 7.5 | 27.5 – 28.5 |
| 59.5 | 10.0 | 2 – 3 | 29.5 – 31.5 |

**UFLS Table 2: Eastern Interconnection**

Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

| UFLS Stage | Frequency Threshold (Hz) | Total Nominal Operating Time(s)[1] | Load Shed at Stage as % of TO or DP Load | Cumulative Load Shed as % of TO or DP Load |
|---|---|---|---|---|
| 1 | 59.5 | 0.30 | 14-25 | 14-25 |
| 2 | 59.1 | 0.30 | 14-25 | 28-50 |

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

**UFLS Table 3: Eastern Interconnection**

Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

| UFLS Stage | Frequency Threshold (Hz) | Total Nominal Operating Time (s)[1] | Load Shed at Stage as % of TO or DP Load | Cumulative Load Shed as % of TO or DP Load |
|---|---|---|---|---|
| 1 | 59.5 | 0.30 | 28-50 | 28-50 |

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

**UFLS Table 4: Quebec Interconnection**

| | Rate | Frequency (Hz) | MW at peak (*Load must be fixed at all times when above 60% of peak load..) | Mvar at peak | Total Nominal Operating Time (s) [2] |
|---|---|---|---|---|---|
| Threshold Stage 1 | —— | 58.5 | 1000* | 1000 | 0.30 |
| Threshold Stage 2 | —— | 58.0 | 800* | 800 | 0.30 |
| Threshold Stage 3 | —— | 57.5 | 800 | 800 | 0.30 |
| Threshold Stage 4 | —— | 57.0 | 800 | 800 | 0.30 |
| Threshold Stage 5 (anti-stall) | —— | 59.0 | 500 | 500 | 20.0 |
| Slope Stage 1 | -0.3 Hz/s | 58.5 | 400 | 400 | 0.30 |
| Slope Stage 2 | -0.4 Hz/s | 59.8 | 800* | 800 | 0.30 |
| Slope Stage 3 | -0.6 Hz/s | 59.8 | 800* | 800 | 0.30 |
| Slope Stage 4 | -0.9 Hz/s | 59.8 | 800 | 800 | 0.30 |

2. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.

## Unofficial Comment Form for Regional Reliability Standard PRC-006-NPCC-1

Please **DO NOT** use this form. Please use the electronic form located at the link below to submit comments on the Regional Reliability Standard **PRC-006-NPCC-1** comments must be submitted by December 22, 2011. If you have questions please contact Howard Gugel at howard.gugel@nerc.net or Barb Nutter at barbara.nutter@nerc.net

http://www.nerc.com/filez/regional_standards/regional_reliability_standards_under_development.html

### Background Information

A regional reliability standard shall be: (1) a regional reliability standard that is more stringent than the continent-wide reliability standard, including a regional standard that addresses matters that the continent-wide reliability standard does not; or (2) a regional reliability standard that is necessitated by a physical difference in the bulk power system. Regional reliability standards shall provide for as much uniformity as possible with reliability standards across the interconnected bulk power system of the North American continent. Regional reliability standards, when approved by FERC and applicable authorities in Mexico and Canada shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the applicable area, regardless of membership in the region.

**PRC-006-NPCC-1** ensures the development of an effective Automatic Underfrequency Load Shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events.

Each **NPCC** Regional Reliability Standard shall enable or support one or more of the NERC reliability principles, thereby ensuring that each standard serves a purpose in support of the reliability of the regional bulk electric system. Each of those standards shall also be consistent with all of the NERC reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence. The NERC reliability principles supported by this standard are the following:

- **Reliability Principle 1** — Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
- **Reliability Principle 2** — The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

The proposed **NPCC** Regional Reliability Standard is not inconsistent with, or less stringent than established NERC Reliability Standards. Once approved by the appropriate authorities, the **NPCC** Regional Reliability Standard obligates the **NPCC** to monitor and enforce compliance, apply sanctions, if any, consistent with any regional agreements and the NERC rules.

**PRC-006-NPCC-1** standard applies to each Generator Owner, Planning Coordinator, Distribution Provider and Transmission Owner in the NPCC region. The purpose of this standard is to provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.

The NPCC **PRC-006-NPCC-1** standard contains 23 main requirements for applicable entities within the NPCC geographic area. The standard contains the following:

**R1** Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS).

**R2** Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics.

**R3** Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1.

**R4** Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3.

**R5** Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall:

**R6** Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4.

**R7** Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay:
7.1 Eastern Interconnection – 100 ms
7.2 Québec Interconnection – 200 ms

**R8** Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program.

**R9** Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds.

**R10** Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9.

**R11** Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9.

**R12** Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays.

**R13** Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19.

**R14** Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request.

**R15** Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% shall

**R16** Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall:

**R17** Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area.

**R18** Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area.

**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:

**R20** The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [

**R21** Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[

**R22** Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21.

**R23** Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21.

The approval process for a regional reliability standard requires NERC to publicly notice and request comment on the proposed standard. Comments shall be permitted only on the following criteria (technical aspects of the standard are vetted through the regional standards development process):

**Unfair or Closed Process —** The regional reliability standard was not developed in a fair and open process that provided an opportunity for all interested parties to participate. Although a NERC-approved regional reliability standards development procedure shall be presumed to be fair and open, objections could be raised regarding the implementation of the procedure.

**Adverse Reliability or Commercial Impact on Other Interconnections —** The regional reliability standard would have a significant adverse impact on reliability or commerce in other interconnections.

**Deficient Standard —** The regional reliability standard fails to provide a level of reliability of the bulk power system such that the regional reliability standard would be likely to cause a serious and substantial threat to public health, safety, welfare, or national security.

**Adverse Impact on Competitive Markets within the Interconnection —** The regional reliability standard would create a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability.

1. **Was the proposed standard developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?**

   ☐ Yes

   ☐ No

   Comments:

2. **Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

   ☐ Yes

   ☐ No

Comments:

3. **Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?**

   ☐ Yes
   ☐ No

   Comments:

4. **Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

   ☐ Yes

   ☐ No

   Comments:

5. **Does the proposed regional reliability standard meet at least one of the following criteria?**
   - **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
   - **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
   - **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

   ☐ Yes

   ☐ No

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Regional Reliability Standards Announcement

## Comment Period Open for PRC-006-NPCC-1
## November 22, 2011–December 22, 2011

**Regional Project: Now Available**

**Proposed Standard for the Northeast Power Coordinating Council (NPCC)**

NPCC has requested NERC to post regional reliability standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding for a 30-day industry review as permitted by the NERC Rules of Procedure.

**Instructions**
Please use this **electronic form** to submit comments. If you experience any difficulties in using the electronic form, please contact Eleanor Crouch at **eleanor.crouch@nerc.net**. An off-line, unofficial copy of the comment form is posted on the **regional standards development page**:

**Background**
**PRC-006-NPCC-1** ensures the development of an effective Automatic Underfrequency Load Shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events.

**Regional Reliability Standards Development Process**
Section 300 of the ***Rules of Procedure for the Electric Reliability Organization*** governs the regional reliability 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 Eleanor Crouch at **eleanor.courch@nerc.net** (via email) or at 404.446.2572.

**3353 Peachtree Road NE**
**Suite 600, North Tower**
**Atlanta, GA 30326**
**404-446-2560 | www.nerc.com**

**Exhibit C**

Standard Drafting Team Roster

**Regional Standard PRC-006-NPCC-1 Automatic UFLS**
**Drafting Team Roster with Biographies**

1. Jonathan Appelbaum--- United Illuminating Company

Mr. Appelbaum holds the position of Director of NERC Compliance at the United Illuminating Company.

Prior to joining UI, Mr. Appelbaum was a Manager at Long Island Power Authority in System Operations where he managed the operational planning and engineering support for transmission system operations. In total he has 21 years of experience in various roles of the electric utility industry including generation, transmission, engineering, automation, and wholesale marketing.

He is familiar with the market and operations procedures at both NYISO, and ISO-NE. He has participated in writing the New York State Reliability Council Rules and assessing compliance to those rules. He has actively participated in the reliability activities of NPCC. In his role in System Operations he was responsible for ensuring compliance with the NPCC criteria for UFLS. He gained experience in applying the details of establishing the UFLS program including how to measure the percentage of load scheduled to be shed, various in feeder loads based on season and the impact on target percentages, scheduling compensating load shed for generators that trip above the target curve, coordinating with generators to change settings to conform with target curves, coordinating with generators on auxiliary equipment relay settings, and assessing compliance of Transmission Owners in New York State to the New York State Reliability Rule requirements for under frequency load shedding. He also participated in the working groups that reviewed the NPCC studies that formed the basis of the current under frequency program.

He has a B.S. in Mechanical Engineering and an MBA.

2. Rich Burke ---ISO-NE (Chairperson):

Principal Analyst, ISO New England Inc. Reliability & Operations Compliance

Richard W. Burke has forty two (42) years of experience in the utility industry. His career began at the Vermont Yankee Nuclear Power Corporation where he performed functions of increasing responsibility over twenty (20) years that included performing as a licensed Senior Operator, serving as the Engineering Department Manager and the Corporate Operations Support Department Manager. Mr. Burke was employed by the Electric Power Research Institute in its Nuclear Power Division for a period of 11 years as a Project Manager and a Program Manager and was a key contributor to EPRI's Advanced Reactor Development program.

In 2000 he began his employment at ISO New England as an Officer of the NEPOOL Reliability & Tariff Technical Committees transferring to the Reliability & Operations Compliance Group in 2006. Mr. Burke has been charged with the overall responsibility of monitoring New England's compliance to the NPCC UFLS Criteria since 2004. He has served as a Member of the NPCC Task Force on System Protection and the NPCC Compliance Committee. Mr. Burke is a graduate of the United States Navy Nuclear Power School and served for six (6) years in the Navy's Nuclear Powered Submarine Program assigned to the Electric Division onboard the U.S.S. Theodore Roosevelt SSB (N) 600.

He holds a Bachelor's degree in Mechanical Engineering from the University of Massachusetts.

3. Stephen Burns ---IESO

Stephen Burns graduated with a B.Sc. (1983) and M. Sc (1985) degrees in electrical engineering from Queen's University, Kingston Ontario. After spending two years at Bruce Nuclear during the commissioning of units at the Bruce B nuclear station, he joined the Power System Operations Division (PSOD) at Ontario Hydro in 1987. From that time to the present, Mr. Burns has conducted operating and planning studies involving the Ontario electricity system. Since 1989 he has worked in various NPCC forums to maintain the reliability of the bulk electricity system. Mr. Burns is a Registered Professional Engineer in the Province of Ontario.

4. Edward F. Dahill--- National Grid

Mr. Dahill has 40 years electric power industry experience with a diverse background of engineering, financial and management responsibilities from working for electric utilities, utility consulting firms and a major industrial entity. He has a record of implementing utility regulatory policies and practices, providing rate case testimony and involvement with non-traditional utility ventures.
Mr. Dahill received his Bachelor of Electrical Engineering Degree from Merrimack College with Masters Degrees from Northeastern University in both Electrical Engineering (Power Option) and Business Administration. He is a licensed professional electrical engineer in the Commonwealth of Massachusetts.
Mr. Dahill's recent primary responsibilities have been associated with the National Grid programs for compliance with the NERC and NPCC Reliability Compliance Enforcement Programs, including National Grid's implementation of NPCC's Directory #12 for Underfrequency Load Shedding. His responsibilities include researching and coordinating National Grid's reliability compliance reporting for NPCC, ISO-NE and NYISO requirements.
Mr. Dahill has represented National Grid on various NERC, NPCC, ISO-NE and NYISO committees, including both the NERC Compliance and Certification Committee and the NPCC Compliance Committee.

5. Carey Fleming--- Constellation

Carey Fleming is in-house nuclear counsel for Constellation Energy Nuclear Group, LLC ("CENG"). CENG operates five nuclear units at the following three sites: Calvert Cliffs (in Maryland), Nine Mile Point (north of Syracuse, NY), and R.E. Ginna (north of Rochester, NY). Mr. Fleming's responsibilities for these nuclear plants focus in the areas of nuclear licensing, administrative law, and regulatory compliance. These duties include providing the company with legal and regulatory analysis and strategy related to CENG's: 1) existing nuclear units; and, 2) potential nuclear acquisitions of existing nuclear facilities owned by others. Prior to joining Constellation in January 2005, Mr. Fleming was an associate in the Washington, DC, office of Winston & Strawn, LLP, providing counsel to clients in the areas of U.S. Nuclear Regulatory Commission ("NRC") regulatory matters.

Before becoming an attorney and joining Winston & Strawn, Mr. Fleming obtained approximately 16 years of experience operating and working at a commercial nuclear facility. While with the utility, Mr. Fleming held an NRC Senior Reactor Operator ("SRO") license for 11 of those years and

worked in the areas of control room operations, classroom and simulator training, root-cause investigation, and regulatory affairs. Mr. Fleming served as a submarine nuclear propulsion plant operator in the U.S. Navy Nuclear Propulsion Program for six years prior to joining the utility.

Mr. Fleming is a summa cum laude graduate of North Carolina Wesleyan College with a B.S. in Computer Information Systems. He received his J.D., cum laude, from North Carolina Central University School of Law, where he was a member of the law journal.
Mr. Fleming is a member of the Bar of the District of Columbia.

6. Robert Giguere--- Entergy

Robert Giguere attended the University of Michigan, served in the U.S. Navy as an electrician and has fourteen years of experience in commercial power plant operations and engineering. During the last four years, Mr. Giguere has worked as an Entergy Nuclear corporate representative for FERC/NERC interface. He has participated in both SERC and NPCC audits and committees. Mr. Giguere has worked with both ISO-NE and NYISO as a member of joint nuclear committees.

7. Brian Evans- Mongeon--- Utility Services

Brian Evans-Mongeon is the President and CEO of Utility Services, Inc., a service firm formed in 2007, specializing in assisting registered entities in the Electric Reliability Organization (ERO) program.

As the President and CEO of Utility Services, he is responsible for oversight of ERO Compliance and Monitoring for client's in regions across the U.S.; ISO & NEPOOL markets; and Renewable Energy Trading and associated activities.

Utility Services is a member in five of the eight NERC regions and its' staff hold a number of committee positions within those regions. Brian is a member of NPCC's Compliance and Regional Standards Committee, and is a participant in the NPCC task force for regional standards on disturbance monitoring.

At NERC, Brian is a participant in the Standard Drafting Team for the Under Frequency Load Shedding program (NERC Project 2007-1), is currently a member of the Definition of Bulk Electric System (BES) team (NERC Project 2010-17), and is the current chair of the Standard Drafting Team for Disturbance and Sabotage Reporting (NERC Project 2009-01). Previously, Brian has over twenty years of experience in the electrical utility business working for both Green Mountain Power Corporation as a Power Operations & Administration Manager and Vermont Public Power Supply Authority as a Marketing Services Manager.

8. Si Truc Phan--- Hydro Quebec TransEnergie

Mr. Phan holds a Bachelors Degree in Power Engineering from the Institute of Technology Superior (Ecole de Technologie Supérieure, Montreal, Canada 1992)

TransEnergie; Hydro-Quebec since 1992
Planning and Operating Strategies for the Main Transmission System ( 18 yrs)
Responsible of the UFLS program for Quebec Interconnection (since 2003)

Responsible of Black Start Restoration Strategies (since 1999)
Responsible of Y2K Study and Strategy for the Main Transmission System (2000)
Responsible of Reliability Standard for the Reliability Coordinator in Quebec (since 2010).
NERC:
Member of Major System Disturbance Task Force for the August 14th 2003 Blackout. (2003)
Member of NERC UFLS Drafting Team (since 2007)

NPCC:
Member Dynamics System Study SS-38 Committee (since 1999)
Member of Regional UFLS Standard Drafting Team (since 2008)
Member of Regional Standard Committee (since 2010)

9. Anie Philip ---LIPA

Ms. Philip joined National Grid in 2003 and has been representing and working on behalf of Long Island Power Authority.

She worked as a transmission planning engineer until September, 2009 and as a Lead Engineer in System Operations until September 2011.

At present, she is the manager of the Transmission Planning. She received a B.S. in Electrical engineering from State University of New York at Stony Brook in 2002 and M.S. in Electrical Engineering from Columbia University in 2008. She is also a NYS licensed Professional Engineer.

10. Jeremiah Stevens---NYIS0

Education: B.S.E.E., M.S.E.E.
Licenses/Certifications: Professional Engineer (New York)

At the time PRC-006-NPCC-01 was written, Mr. Stevens was employed by the New York Independent System Operator.

Brief Description of Experience Relevant to PRC-006-NPCC-01:

Responsible for the UF tripping data collection from entities within the New York Control Area.

11. Jason Savulak----Hydro One

Masters and Bachelor of Science in Electrical engineering from the University of Waterloo.

Mr. Savulak has been working for Hydro One, the primary transmission company in Ontario for approximately 8 years. He works in Operations dealing mostly with system assessments and providing real-time technical analysis and support.

12. Khin Swe ---NYPA

Khin T. M. Swe joined NYPA Transmission Planning Department as a System Planning Engineer in 2006. Performed various system studies such as: Wind Farms Combined Effect on the 230kV

Transmission System of North Eastern NY; Alternative NYPA Plan of Under Frequency Load Shedding (for NPCC Directory 12); SPS classifications and impact studies, and classification tests for Bulk Power System (BPS) elements (NPCC A-10). The studies involved performing load flow, voltage drop and stability studies. She evaluates System Reliability Impact Studies (SRIS) for those projects requesting to connect to NYPA Transmission System. She represents NYPA on NPCC Task Force on System Studies (TFSS). She was a member on NPCC Inter-Area Dynamic Analysis Working Group (SS-38) presenting NYPA. Prior to NYPA, she worked for Washington Group International (formerly Ebasco or Raytheon Engineers & Constructors, New York, NY). She performed many power system studies and substation control design on various utilities projects. She completed her BSEE in 1980 and MSEE in 1984 from the Polytechnic Institute of New York. She is a member of IEEE, engineering honor society Tau Beta Pi and Eta Kappa Nu.

13. Dan Taft ---Consolidated Edison Company of NY

Mr. Taft holds a Bachelor of Engineering in Electrical Engineering from Stevens Institute of Technology in Hoboken, NJ (May 1979) and a Master of Engineering in Electric Power Engineering from Rensselaer Polytechnic Institute in Troy, NY (May 1990)

Mr. Taft began his career with General Electric in 1979 in the area of Protective Relaying, then moved on to Hubbell, Incorporated in 1985 to work on Ground Fault Interrupters and Surge Suppressors. After earning a Master's degree in the field of Electric Power Engineering, he went to work for Con Edison in 1990, again in the area of Protective Relaying. He became a Senior System Operator in the Con Edison's Control Center in 2003. In 2006, he became a Section Manager in Con Edison's Transmission Planning Dept. In 2009, he took a position at the Federal Energy Regulatory Commission in the Office of Electric Reliability, and returned to Con Edison in 2011 as a Section Manager of the Operations Analysis Group in the System Operation Dept.

14. Mohsen Zam Zam---Consolidated Edison Company of NY

Mr. Zam has worked in the utility business for over twenty five years. Most of his career has been devoted to planning and evaluating the transmission and the performance of the Bulk power system.

He is member of the NPCC System Studies SS-38 group responsible for evaluating the adequacy of the Under Frequency Load Shedding (UFLS) protection schemes.He also plans and determines the stages and the frequency settings for the Con Edison's UFLS scheme in accordance with the NPCC standards. He participated in the simulations and re-creation of the August 14, 2003 Blackout events.

Mr. Zam coauthored an IEEE paper with PTI personnel on system restoration including the development of eight restoration plans to restore the Con Edison system following a total system shutdown with and without external help. He evaluates new technology and new energy sources such as HVDC, Wind Mill generators, FACT devices and VFT and determines their impact on the bulk power transmission system.

He was involved with the installation of Phasor Measuring Units (PMU) on the transmission system for system operation wide area visualization. He was also involved in investigating the implementation of the Synchro-phasor technology for monitoring the Bulk Power System for the entire Eastern seaport electric grid.

15. Guy Zito ---NPCC

Education: B.S.E.E., PTI Licenses/Certifications

Employer at the time PRC-006-NPCC-01 was written: Northeast Power Coordinating Council

Brief Description of Experience Relevant to PRC-006-NPCC-01:

Planning and Operating experience of Transmission and Distribution systems, reviewed system disturbances and the data required to properly analyze and mitigate those occurrences.

13. Lee Pedowicz ---NPCC

Education: B.S.E.E., M.S.--Electric Power Engineering, G.E. Power Systems Engineering Course
Licenses/Certifications: Professional Engineer (New York), NERC Reliability Operator

Employer at the time PRC-006-NPCC-01 was written: Northeast Power Coordinating Council

Brief Description of Experience Relevant to PRC-006-NPCC-01:

Bulk and Distribution Power System Operations which utilized UFLS equipment as a last resort to maintain system security.

14. Gerry Dunbar---NPCC

Education: B.A. Economics, Siemens Power Technology Course
Licenses/Certifications:

Employer at the time PRC-006-NPCC-01 was written: Northeast Power Coordinating Council
Brief Description of Experience Relevant to PRC-006-NPCC-01:

Thirty years of power system operations experience which included assignments as a qualified bulk power substation operator, instructor substation operations, control room operator (transmission and distribution operations).

**Exhibit D**

PRC-006-NPCC-1 Violation Severity Level and Violation Risk Factor Analysis

# NPCC Regional UFLS Standard PRC-006-NPCC-1
# VRF and VSL Justification

This document provides the justification for assignment of VRFs and VSLs, identifying how each proposed VRF and VSL meets NERC's criteria and FERC's Guidelines. NERC's criteria for setting VRFs and VSLs; FERC's five guidelines (G1 – G5) for approving VRFs; and FERC's four guidelines (G1-G4) for setting VSLs are provided at the end of this document.

| VRF and VSL Justifications | | |
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| R1 | Proposed VRF | Medium |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>System modeling and data exchange. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This requirement in the proposed standard determines the UFLS programs to respond to islanding situations and compensatory load shedding, and has been assigned a Medium Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>The requirements in PRC-006-NPCC-1 Automatic Underfrequency Load Shedding that pertain to the determination of islands have been assigned a Medium Violation Risk Factor, consistent with the VRF assignments in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The Medium VRF assignment is consistent with the NERC definition in that it is 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement is referred to in Requirement R3. Requirement R1 has the higher Medium VRF. Requirement R3 has been assigned a Low VRF.<br><br>The proposed Requirement is referred to in Requirement R6. Requirement R1 has the higher Medium VRF. Requirement R6 has been assigned a High VRF, and is not diminished by this VRF assignment. |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | N/A |
| | Proposed High VSL | Planning Coordinator did not establish requirements for entities aggregating their UFLS programs.<br>or<br>Did not establish requirements for compensatory load shedding. |
| | Proposed Severe VSL | Planning Coordinator did not establish requirements for entities aggregating their UFLS programs and did not establish requirements for compensatory load shedding. |

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| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | Requirements R1 in PRC-006-1 and PRC-006-NPCC-1 each address a Planning Coordinator's responsibility for determining system islanding.<br><br>Lower: Not applicable in PRC-006-1 and PRC-006-NPCC-1.<br><br>Moderate: Not applicable in PRC-006-NPCC-1, but does not lower the level of compliance. PRC-006-1 assigned a Moderate VSL for a Planning Coordinator failed to consider historical events, or 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.<br><br>High: PRC-006-1 assigned a High VSL for a Planning Coordinator failing to consider historical events, or 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. PRC-006-NPCC-1 is more stringent in that it considers the impact of a Planning Coordinator not establishing the requirements for entities aggregating their UFLS programs, or did not establish the requirements for compensatory load shedding.<br><br>Severe: PRC-006-1 assigned a Severe VSL for a Planning Coordinator failing 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. PRC-006-NPCC-1 is more stringent in that it considers the impact of a Planning Coordinator not establishing the requirements for entities aggregating their UFLS programs, and not establishing the requirements for compensatory load shedding. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a: The VSL is not binary and does not violate this guideline.<br><br>Guideline 2b: The VSL is gradated properly. The violation gradations do not overlap. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |

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| | Requirement | |
| | **FERC VSL G4**<br>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. |

| **VRF and VSL Justifications** | | |
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| R2 | Proposed VRF | Medium |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>System modeling and data exchange. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This requirement in the proposed standard pertains to the time for the Planning Coordinator to identify to the Regional Entity generation facilities to support the UFLS program characteristics, and has been assigned a Medium Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>The requirements in PRC-006-NPCC-1 Automatic Underfrequency Load Shedding that pertain to the determination of islands have been assigned a Medium Violation Risk Factor, consistent with the VRF assignments in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The Medium VRF assignment is consistent with the NERC definition in that it is 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>Not applicable. |
| | Proposed Lower VSL | The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies. |
| | Proposed Moderate VSL | The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies. |
| | Proposed High VSL | The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies. |
| | Proposed Severe VSL | The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 60 days after completion of the system studies. |

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| | | or<br>The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | Requirement R2 in PRC-006-NPCC-1 addresses a Planning Coordinator's responsibility for identifying to the Regional Entity the generation facilities within its Area necessary to support the UFLS program performance characteristics. Requirements R3 and R4 in PRC-006-1 specify the generation by facility nameplate rating.<br><br>Lower: Not applicable in PRC-006-1 R3, but R4 assigned a Lower VSL for a failure to include one of the items listed in its Parts 4.1 through 4.7 in a UFLS assessment, which includes the generation specification. PRC-006-NPCC-1 addresses a delay in the identification of generation facilities within its Planning Coordinator Area more than 30 days, but less than 41 days after the completion of the system studies. The current level of compliance is not lowered.<br><br>Moderate: PRC-006-1 R3 assigned a Moderate VSL for a Planning Coordinator failing to meet one of the performance characteristics specified in Part s 3.3.1, 3.3.2, and 3.3.3 addressing generation. PRC-006-1 R4 assigned a Moderate VSL for a failure to include two of the items listed in Parts 4.1 through 4.7. PRC-006-NPCC-1 addresses a delay in the identification of generation facilities within its Planning Coordinator Area more than 40 days, but less than 51 days after the completion of the system studies. The current level of compliance is not lowered.<br><br>High: PRC-006-1 R3 assigned a High VSL for a Planning Coordinator failing to meet two of the performance characteristics specified in Parts 3.3.1, 3.3.2, and 3.3.3 addressing generation. PRC-006-1 R4 assigned a High VSL for a failure to include three of the items listed in Parts 4.1 through 4.7. PRC-006-NPCC-1 addresses a delay in the identification of generation facilities within its Planning Coordinator Area more than 50 days, but less than 61 days after the completion of the system studies. The current level of compliance is not lowered.<br><br>Severe: PRC-006-1 R3 assigned a Severe VSL for a Planning Coordinator failing to meet all of the performance characteristics specified in Parts 3.3.1, 3.3.2, and 3.3.3 addressing generation, or failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area. PRC-006-1 R4 assigned a Severe VSL for a failure to include four or more of the items listed in Parts 4.1 through 4.7, or failure 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-NPCC-1 addresses a delay in the identification of generation facilities within its Planning Coordinator Area more than 60 days after the completion of the system studies, or the Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program. The current level of compliance is not lowered. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should | Guideline 2a-- the VSL is not binary and does not violate this guideline.<br><br>Guideline 2b--the VSL does not contain ambiguous language. |

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| | Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |
| **VRF and VSL Justifications** | | |
| R3 | Proposed VRF | Lower |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>System modeling and data exchange |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard pertains to time requirements for submitting information and has been assigned a Lower Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards.<br>The requirements in PRC-006-1 do not have a time deadline requirement for providing information to Transmission Owners, Distribution Providers, and Generator Owners. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>This Requirement has a Lower VRF because it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement refers to Requirement R1 which has a Medium |

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| | | VRF. This Requirement has been assigned a Low VRF because it addresses the time to submit information, and does not diminish the Medium VRF for R1. |
| | Proposed Lower VSL | The Planning Coordinator provided the requested information, but did so more than 30 days but less than 41 days to the requesting entity. |
| | Proposed Moderate VSL | The Planning Coordinator provided the requested information, but did so more than 40 days but less than 51 days to the requesting entity. |
| | Proposed High VSL | The Planning Coordinator provided the requested information, but did so more than 50 days but less than 61 days to the requesting entity. |
| | Proposed Severe VSL | The Planning Coordinator provided the requested information, but did so more than 60 days after the request.<br>or<br>The Planning Coordinator failed to provide the requested information. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | The requirements in PRC-006-1 do not have a time deadline requirement for providing information to Transmission Owners, Distribution Providers, and Generator Owners. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is not binary and does not violate this guideline.<br><br>Guideline 2b--the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |

| VRF and VSL Justifications | | |
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| R4 | Proposed VRF | High |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>Protection systems and their coordination. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard pertains to the implementation of an automatic UFLS program and has been assigned a High Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>The requirements in PRC-006-NPCC-1 Automatic Underfrequency Load Shedding that pertains to the implementation of automatic tripping of load has been assigned a High Violation Risk Factor, consistent with the VRF assignment in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement is referred to in R5. Both Requirements have been assigned a High VRF. |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | N/A |
| | Proposed High VSL | N/A |
| | Proposed Severe VSL | The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | Requirement R9 in PRC-006-1 addresses the tripping of load for automatic UFLs programs.<br><br>Lower: Not applicable in PRC-006-NPCC-1. PRC-006-1 assigned a Lower VSL to an entity for providing less than 100% but more than 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.<br>.<br><br>Moderate: Not applicable in PRC-006-NPCC-1. PRC-006-1 assigned a Moderate VSL to an entity for providing less than 95% but more than 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. |

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| | | High: Not applicable in PRC-006-NPCC-1. PRC-006-1 assigned a High VSL to an entity for providing less than 90% but more 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.<br><br>Severe: PRC-006-NPCC-1 assigns a Severe VSL for a Distribution Provider or Transmission Owner failing to implement an automatic UFLS program as described in the Standard. PRC-006-1 assigned a Severe VSL to an entity for providing 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.<br><br>The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned.<br><br>Guideline 2b-- the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |

| VRF and VSL Justifications | | |
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| R5 | Proposed VRF | High |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>Protection systems and their coordination. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard pertains to the implementation of an automatic UFLS program and has been assigned a High Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>PRC-006-1 Requirement R12 mandates a UFLS design assessment if event assessment program deficiencies are identified, and has a Medium VRF. PRC-006-NPCC-1 Requirement R5 addresses exceeding tolerances and deviations with a High VRF, which is consistent with the NERC definition of a High VRF. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement refers to elements in Requirement R4. Both Requirements have been assigned a High VRF. |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table 2 only, the need to deviate from providing two stages of UFLS. |
| | Proposed High VSL | The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with the appropriate table. |
| | Proposed Severe VSL | The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load. |

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| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | PRC-006-1 Requirement R12 mandates a UFLS design assessment if event assessment program deficiencies are identified.<br><br>Lower: Not applicable in PRC-006-NPCC-1, nor PRC-006-1.<br><br>Moderate: PRC-006-NPCC-1 assigned a Moderate VSL to an entity if it exceeded tolerances and/or deviated from the number of stages and frequency setpoints of the UFLS program, and did not inform the Planning Coordinator of the need to exceed the stated tolerances. PRC-006-1 addresses the failure of a Planning Coordinator to conform to the consideration of identified deficiencies greater than two years but less than or equal to 25 months of event actuation.<br><br>High: PRC-006-NPCC-1 assigned a High VSL to an entity if it exceeded tolerances and/or deviated from the number of stages and frequency setpoints of the UFLS program, and did not provide the Planning Coordinator with an analysis demonstrating alternative solutions. PRC-006-1 addresses the failure of a Planning Coordinator to conform to the consideration of identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.<br>Severe: PRC-006-NPCC-1 assigned a Severe VSL to an entity if it did not arm its load to trip on Underfrequency and exceeded tolerances and/or deviated from the number of stages and frequency setpoints of the UFLS program. PRC-006-1 addresses the failure of a Planning Coordinator to conform to the consideration of identified deficiencies greater than 26 months of event actuation, or the Planning Coordinator with deficiencies failed to conduct and document a UFLS design assessment to consider the identified deficiencies.<br><br>The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is not binary and does not violate this guideline.<br><br>Guideline 2b--the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |

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| | Assignment Should Be Consistent with the Corresponding Requirement | |
| | **FERC VSL G4**<br>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. |
| **VRF and VSL Justifications** | | |
| R6 | Proposed VRF | High |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>Protection systems and their coordination. This Requirement pertains to the Quebec Interconnection. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard pertains to the implementation of an automatic UFLS program and has been assigned a High Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>PRC-006-NPCC-1 addresses the implementation of an automatic UFLS program in the Quebec Interconnection, with a High VRF. Section E Regional Variances of PRC-006-1addresses the Regional Variances for the Quebec Interconnection. Requirements E.A.3, and E.A. 4 addressing the Quebec Interconnection automatic UFLS program each have been assigned a High VRF. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement has been assigned a High VRF, and refers to elements in Requirement R1. Requirement R1 has been assigned a Medium VRF because it deals with the establishment of aggregating UFLS programs. This Requirement's VRF assignment is not diminished. |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | N/A |
| | Proposed High VSL | N/A |
| | Proposed Severe VSL | The Distribution Provider or Transmission Owner in the Québec Interconnection portion of NPCC did not implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total |

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| | | nominal operating time and amounts specified in Attachment C, Table 4 or did not collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | Section E Regional Variances of PRC-006-1addresses the tripping of load for automatic UFLs programs in the Quebec Interconnection.<br><br>Lower: Not applicable in PRC-006-NPCC-1. PRC-006-1 assigned a Lower VSL to an entity for providing less than 100% but more than 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.<br><br>Moderate: Not applicable in PRC-006-NPCC-1. PRC-006-1 assigned a Moderate VSL to an entity for providing less than 95% but more than 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.<br><br>High: Not applicable in PRC-006-NPCC-1. PRC-006-1 assigned a High VSL to an entity for providing less than 90% but more 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.<br><br>Severe: PRC-006-NPCC-1 assigns a Severe VSL for a Distribution Provider or Transmission Owner failing to implement an automatic UFLS program as described in the Standard. PRC-006-1 assigned a Severe VSL to an entity for providing 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.<br><br>The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned.<br><br>Guideline 2b-- the VSL does not contain ambiguous language. |

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| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |
| **VRF and VSL Justifications** | | |
| R7 | Proposed VRF | High |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>Protection systems and their coordination. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard pertains to the implementation of an automatic UFLS program have been assigned a High Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>The requirements in PRC-006-1 do not address specific time delay parameters. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>Not applicable. |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | N/A |
| | Proposed High VSL | N/A |
| | Proposed Severe VSL | The Distribution Provider or Transmission Owner failed to set an underfrequency relay that is part of its region's UFLS program as specified in Requirement R7. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current | The requirements in PRC-006-1 do not specify time delay parameters. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |

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| | Level of Compliance | |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned.<br><br>Guideline 2b-- the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |
| **VRF and VSL Justifications** | | |
| R8 | Proposed VRF | Medium |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>System modeling and data exchange. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard pertains to the development and review inhibit threshold settings, and is assigned a Medium Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>This Requirement pertains to the development and review of inhibit threshold settings. These settings are not addressed in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>This Requirement has a Medium VRF because it 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 |

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| | | restore the bulk electric system. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>Not applicable. |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | N/A |
| | Proposed High VSL | The Planning Coordinator developed inhibit thresholds as specified in Requirement R8 but did not perform the review once per calendar year. |
| | Proposed Severe VSL | The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R8. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | The requirements in PRC-006-1 do not address the development and review of inhibit threshold settings. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is not binary and does not violate this guideline.<br><br>Guideline 2b--the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |

| VRF and VSL Justifications | | |
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| R9 | Proposed VRF | Medium |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>System modeling and data exchange. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard pertains to providing inhibit thresholds, and is assigned a Medium Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>This Requirement pertains to the providing of inhibit threshold settings to the Transmission Owner and Distribution Provider. This is not addressed in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>This Requirement has a Medium VRF because it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement is referred to in Requirement R10. Requirement R10 has a High VRF. This requirement has been assigned a Medium VRF because it addresses the time to submit information, and does not diminish the High VRF for R10.<br><br>The proposed Requirement is referred to in Requirement R11. Requirement R11 has a Lower VRF because it addresses the time for the submission of an implementation plan. This requirement is not diminished by the Requirement R11 Lower VRF.. |
| | Proposed Lower VSL | The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds. |
| | Proposed Moderate VSL | The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds. |
| | Proposed High VSL | The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds. |
| | Proposed Severe VSL | The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds.<br>or<br>The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds. |

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| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | The requirements in PRC-006-1 do not address the providing of inhibit thresholds to the Transmission Owner and Distribution Provider. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is not binary and does not violate this guideline.<br><br>Guideline 2b--the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |
| **VRF and VSL Justifications** | | |
| R10 | Proposed VRF | High |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>Protection systems and their coordination. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard pertains to the implementation of the inhibit threshold settings, and is assigned a High Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>This Requirement pertains to the implementation of inhibit threshold settings by the Transmission Owner and Distribution Provider. This is not addressed |

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| | | in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement refers to Requirement R9 which has a Medium VRF. This Requirement has been assigned a High VRF because it addresses implementing the inhibit threshold settings specified in Requirement R9, and its High VRF is not diminished. |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | N/A |
| | Proposed High VSL | N/A |
| | Proposed Severe VSL | The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with Requirement R9. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | The requirements in PRC-006-1 do not address the implementation of inhibit threshold settings. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned.<br><br>Guideline 2b-- the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |

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| | **FERC VSL G4**<br>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. |
| **VRF and VSL Justifications** | | |
| R11 | Proposed VRF | Lower |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>System modeling and data exchange. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard pertains to the time for submitting an implementation of the inhibit threshold settings, and is assigned a Lower Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>This Requirement pertains to the development and submission of an implementation plan in accordance with R9 for inhibit thresholds. This is not addressed in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>This Requirement has a Lower VRF because it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement refers to Requirement R9 which has a Medium VRF. This Requirement has been assigned a Lower VRF because it addresses the time to submit an implementation plan. The Requirement R9 Medium VRF is not diminished. |
| | Proposed Lower VSL | The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator. |
| | Proposed Moderate VSL | The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator. |
| | Proposed High VSL | The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator. |
| | Proposed Severe VSL | The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator.<br>or<br>The Distribution Provider or Transmission Owner did not develop its implementation plan. |

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| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | The requirements in PRC-006-1 do not address the implementation of inhibit threshold settings. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is not binary and does not violate this guideline.<br><br>Guideline 2b--the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |
| **VRF and VSL Justifications** | | |
| R12 | Proposed VRF | Lower |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>System modeling and data exchange. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard pertains to the provision of documentation to the Planning Coordinator of the actual net Load that would be shed by the UFLS relays at each stage, and is assigned a Lower Violation Risk Factor. |
| | FERC VRF G3 | Guideline 3- Consistency among Reliability Standards |

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| | Discussion | This Requirement pertains to the provision of documentation to the Planning Coordinator of the actual net Load that would be shed by the UFLS relays at each stage. This is not addressed in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>This Requirement has a Lower VRF because it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>Not applicable. |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | N/A |
| | Proposed High VSL | N/A |
| | Proposed Severe VSL | The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | The requirements in PRC-006-1 do not address the provision of documentation to the Planning Coordinator of the actual net Load by the UFLS relays at each stage. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned.<br><br>Guideline 2b-- the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |

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| | Requirement | |
| | **FERC VSL G4**<br>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. |
| **VRF and VSL Justifications** | | |
| R13 | Proposed VRF | High |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>Protection systems and their coordination. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard pertains to the setting of generator underfrequency trip relays, and has been assigned a High Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>This requirement pertains to the setting of generator underfrequency trip relays. This is not addressed in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement has been assigned a High VRF, and refers to Requirement R16 (High VRF), and Requirement R19 (High VRF). |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | N/A |
| | Proposed High VSL | N/A |
| | Proposed Severe VSL | The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | The Requirements in PRC-006-1 do not address the setting of generator underfrequency trip relays. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should | Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned. |

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| | Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2b-- the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |
| **VRF and VSL Justifications** | | |
| R14 | Proposed VRF | High |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>System modeling and data exchange. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard pertains to the transmission of generator underfrequency trip settings and time delays to the Planning Coordinator, and has been assigned a High Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>This requirement pertains to the transmission of generator underfrequency trip settings and time delays to the Planning Coordinator. This is not addressed in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The transmitting of this information to the Planning Coordinator is critical to the establishment of an effective automatic UFLS program. Thus the assignment of the High Violation Risk Factor that is High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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. |

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| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>Not applicable. |
| | Proposed Lower VSL | The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator's request. |
| | Proposed Moderate VSL | The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator's request. |
| | Proposed High VSL | The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator's request. |
| | Proposed Severe VSL | The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75days after the Planning Coordinator's request.<br>or<br><br>The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | The requirements in PRC-006-1 do not address the transmission of generator underfrequency trip settings and time delays. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is not binary and does not violate this guideline.<br><br>Guideline 2b--the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4** | The VSL is based on a single violation. |

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| | Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations | |

| VRF and VSL Justifications | | |
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| R15 | Proposed VRF | High |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>Protection systems an d their coordination. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard pertains to Generator Owners to design systems to prevent undesired tripping for system conditions above underfrequency trip thresholds, and has been assigned a High Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>This Requirement pertains to Generator Owners to design systems to prevent undesired tripping for system conditions above underfrequency trip thresholds. This is not addressed in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>Not applicable. |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | N/A |
| | Proposed High VSL | The Generator Owner did not fulfill the obligation of Requirement R15; Part 15.1 OR did not fulfill the obligation of Requirement R15, Part 15.2. |
| | Proposed Severe VSL | The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1 and did not fulfill the obligation of Requirement R15, Part 15.2. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | The requirements in PRC-006-1 do not address Generator Owners designing systems to prevent undesired tripping for underfrequency system conditions. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements | Guideline 2a-- the VSL is not binary and does not violate this guideline.<br><br>Guideline 2b--the VSL does not contain ambiguous language. |

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| | Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |

| **VRF and VSL Justifications** | | |
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| R16 | Proposed VRF | High |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>Protection systems and their coordination. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the posposed standard pertains to Generator Owners of existing non-nuclear units in service that have underfrequency protection set to trip above the appropriate curve in the standard, and has been assigned a High Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>This Requirement pertains to Generator Owners of existing non-nuclear units in service that have underfrequency protection set to trip above the appropriate curve in the standard. This is not addressed in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement is referred to in Requirement R13. Requirement R13 has been assigned a High VRF. This requirement has also been assigned a High VRF.<br><br>The proposed Requirement (R16.3) is referred to in Requirement R17. Requirement R17 has been assigned a High VRF. This requirement has also |

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| | | been assigned a High VRF.<br><br>The proposed Requirement (R16.3) is referred to in Requirement R18. Requirement R18 has been assigned a High VRF. This requirement has also been assigned a High VRF. |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.2. |
| | Proposed High VSL | The Generator Owner did not fulfill the obligation of Requirement R16; Part 16.1 OR did not fulfill the obligation of Requirement R16, Part 16.3. |
| | Proposed Severe VSL | The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.1 and did not fulfill the obligation of Requirement R16, Part 16.3. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | The Requirements in PRC-006-1 do not address Generator Owners of existing non-nuclear units in service that have underfrequency protection set to trip above the appropriate curve in the standard. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is not binary and does not violate this guideline.<br><br>Guideline 2b--the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of | The VSL is based on a single violation. |

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| | Violations | |
| **VRF and VSL Justifications** | | |
| R17 | Proposed VRF | High |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>System modeling and data exchange. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard pertains to the Planning Coordinators in Ontario, Quebec and the Maritime Provinces for determining compensatory load shedding, and has been assigned a High Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards.<br>This Requirement pertains to the Planning Coordinators in Ontario, Quebec and the Maritime Provinces for determining compensatory load shedding. This is not addressed in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement has been assigned a High VRF, and refers to Requirement R16.3 (High VRF). |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | N/A |
| | Proposed High VSL | N/A |
| | Proposed Severe VSL | The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | The Requirements in PRC-006-1 do not address the Planning Coordinators in Ontario, Quebec and the Maritime Provinces determining compensatory load shedding. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for | Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned.<br><br>Guideline 2b-- the VSL does not contain ambiguous language. |

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| | "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |
| **VRF and VSL Justifications** | | |
| R18 | Proposed VRF | High |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>System modeling and data exchange. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard pertains to the Generator Owner, Distribution Provider or Transmission Owner applying criteria to determine compensatory load shedding, and has been assigned a High Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>This Requirement pertains to the Generator Owner, Distribution Provider or Transmission Owner applying criteria to determine compensatory load shedding. This is not addressed in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement has been assigned a High VRF, and refers to Requirement R16.3 (High VRF). |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | N/A |

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| | Proposed High VSL | N/A |
| | Proposed Severe VSL | The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | The Requirements in PRC-006-1 do not address the Generator Owner, Distribution Provider or Transmission Owner applying criteria to determine compensatory load shedding. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned.<br><br>Guideline 2b-- the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |

| **VRF and VSL Justifications** | | |
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| R19 | Proposed VRF | High |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>Protection systems and their coordination. |
| | FERC VRF G2 | Guideline 2- Consistency within a Reliability Standard |

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| | Discussion | This Requirement in the proposed standard pertains to Generator Owners of existing nuclear units in service that have underfrequency protection set to trip above the appropriate curve in the standard, and has been assigned a High Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>This Requirement pertains to Generator Owners of existing nuclear units in service that have underfrequency protection set to trip above the appropriate curve in the standard. This is not addressed in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement is referred to in Requirement R13. Requirement R13 has been assigned a High VRF. This requirement has also been assigned a High VRF. |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.3. |
| | Proposed High VSL | The Generator Owner did not fulfill the obligation of Requirement R19; Part 19.1 OR did not fulfill the obligation of Requirement R19, Part 19.2. |
| | Proposed Severe VSL | The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.1 and did not fulfill the obligation of Requirement R19, Part 19.2. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | The Requirements in PRC-006-1 do not address Generator Owners of existing nuclear units in service that have underfrequency protection set to trip above the appropriate curve in the standard. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is not binary and does not violate this guideline.<br><br>Guideline 2b--the VSL does not contain ambiguous language. |

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| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |
| **VRF and VSL Justifications** | | |
| R20 | Proposed VRF | Lower |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>System modeling and data exchange. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard addresses the Planning Coordinator updating its UFLS program database as specified by PRC-006-1, and has been assigned a Lower Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>This Requirement addresses the Planning Coordinator updating its UFLS program database as specified by PRC-006-1. This Requirement is assigned a Lower Violation Risk Factor. PRC-006-1 Requirements R6, R7, and R8 deal with the UFLS database. Each of those three Requirements has been assigned a Lower Violation Risk Factor. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>This Lower VRF is consistent with the NERC definition because the Requirement 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>Not applicable. |
| | Proposed Lower VSL | The Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5. |
| | Proposed Moderate VSL | The Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5. |
| | Proposed High VSL | The Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5. |
| | Proposed Severe VSL | The Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5. |
| | **FERC VSL G1**<br>Violation Severity Level | This requirement and PRC-006-1 Requirements R6, R7, and R8 all address the UFLS database. |

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| | Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | Lower: PRC-006-NPCC-1 Requirement R20 assigned a Lower VSL if the Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5. PRC-006-1 R6 did not assign a Lower VSL. PRC-006-1 R7 assigned a Lower VSL if 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. PRC-006-1 R8 assigned a Lower VSL if 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.<br><br>Moderate: PRC-006-NPCC-1 Requirement R20 assigned a Moderate VSL if the Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5. PRC-006-1 R6 did not assign a Moderate VSL. PRC-006-1 R7 assigned a Moderate VSL if the Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days and up to and including 50 calendar days following the request. PRC-006-1 R8 assigned a Moderate VSL if 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) 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.<br><br>High: PRC-006-NPCC-1 Requirement R20 assigned a High VSL if the Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5. PRC-006-1 R6 did not assign a High VSL. PRC-006-1 R7 assigned a High VSL if the Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days and up to and including 60 calendar days following the request. PRC-006-1 R8 assigned a High VSL if 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.<br><br>Severe: PRC-006-NPCC-1 Requirement R20 assigned a Severe VSL if the Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5. PRC-006-1 R6 assigned a Severe VSL if the Planning Coordinator failed to maintain a UFLS database 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. PRC-006-1 R7 assigned a Severe VSL if 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 assigned a Severe VSL if 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 |

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| | | entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.<br>. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is not binary and does not violate this guideline.<br><br>Guideline 2b--the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |
| **VRF and VSL Justifications** | | |
| R21 | Proposed VRF | High |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>System modeling and data exchange. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard addresses the Planning Coordinator notifying the Distribution Provider, Transmission Owner, and Generator Owner of changes to load distribution needed to satisfy UFLS program characteristics as specified in NERC PRC-006-1 Requirements R3, and R4, and has been assigned a High Violation Risk Factor. |
| | FERC VRF G3 | Guideline 3- Consistency among Reliability Standards |

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| | Discussion | This Requirement addresses the Planning Coordinator notifying the Distribution Provider, Transmission Owner, and Generator Owner of changes to load distribution needed to satisfy UFLS program characteristics as specified in NERC PRC-006-1 Requirements R3, and R4. This Requirement has been assigned a High Violation Risk Factor. PRC-006-1 Requirements R3, and R4 each have been assigned a High Violation Risk Factor. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement is referred to in Requirement R22. Requirement R22 has been assigned a High VRF. This requirement has also been assigned a High VRF.<br><br>The proposed Requirement is referred to in Requirement R23. Requirement R23 has been assigned a Lower VRF because it deals with the time to submit an implementation in accordance with Requirement R21. This Requirement has been assigned a High VRF, and is not diminished by the R23 Lower VRF. |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | N/A |
| | Proposed High VSL | N/A |
| | Proposed Severe VSL | The Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | This Requirement and PRC-006-1 R3, and R4 address notifications of load distribution needed to satisfy UFLS program performance characteristics.<br><br>Lower: Not applicable in PRC-006-NPCC-1 R21. Not applicable in PRC-006-1 R3. PRC-006-1 R4 assigned a Lower VSL if the Planning Coordinator 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 characterisitics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one of the items as specified in Requirement R4, Parts 4.1 through 4.7.<br><br>Moderate: Not applicable in PRC-006-NPCC-1 R21. PRC-006-1 R3 assigned a Moderate VSL if 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 of the performance characteristics in Requirement R3, Parts 3.1, |

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| | | 3.2, or 3.3 in simulations of underfrequency conditions. PRC-006-1 R4 assigned a Moderate VSL if the Planning Coordinator 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 two of the items as specified in Requirement R4, Parts 4.1 through 4.7.<br><br>High: Not applicable in PRC-006-NPCC-1 R21. PRC-006-1 R3 assigned a High VSL if 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 of the performance characteristics in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions. PRC-006-1 R4 assigned a High VSL if the Planning Coordinator 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 three of the items as specified in Requirement R4, Parts 4.1 through 4.7.<br><br>Severe: PRC-006-NPCC-1 R21 assigned a Severe VSL if the Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements. PRC-006-1 R3 assigned a Severe VSL if 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 characteristics in Requirement R3, Parts 3.1, 3.2, or 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 assigned a Severe VSL if the Planning Coordinator 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 four 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. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties | Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned.<br><br>Guideline 2b-- the VSL does not contain ambiguous language. |

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| | Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |
| **VRF and VSL Justifications** | | |
| R22 | Proposed VRF | High |
| | NERC VRF Discussion | |
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>Protection systems and their coordination. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard addresses the Distribution Provider, Transmission Owner, and Generator Owner implementing load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21, and has been assigned a High Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>This Requirement addresses the Distribution Provider, Transmission Owner, and Generator Owner implementing the load distribution changes based on the notification provided by the Planning Coordinator. This Requirement has been assigned a High Violation Risk Factor. This is not addressed in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement has been assigned a High VRF, and refers to |

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| | | Requirement R21which has been assigned a High VRF. |
| | Proposed Lower VSL | N/A |
| | Proposed Moderate VSL | N/A |
| | Proposed High VSL | N/A |
| | Proposed Severe VSL | The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | The Requirements in PRC-006-1 do not address the Distribution Provider, Transmission Owner, and Generator Owner implementing the load distribution changes based on the notification provided by the Planning Coordinator. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned.<br><br>Guideline 2b-- the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |
| **VRF and VSL Justifications** | | |
| R23 | Proposed VRF | Lower |
| | NERC VRF Discussion | |

| | | |
|---|---|---|
| | FERC VRF G1 Discussion | Guideline 1- Consistency w/ Blackout Report<br>System modeling and data exchange. |
| | FERC VRF G2 Discussion | Guideline 2- Consistency within a Reliability Standard<br>This Requirement in the proposed standard addresses the Distribution provider, Transmission Owner and Generator developing and submitting an implementation plan within 90 days of a request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21, and has been assigned a Lower Violation Risk Factor. |
| | FERC VRF G3 Discussion | Guideline 3- Consistency among Reliability Standards<br>This Requirement addresses the Distribution Provider, Transmission Owner and Generator developing and submitting an implementation plan within 90 days of a request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. This Requirement has been assigned a High Violation Risk Factor. This is not addressed in PRC-006-1. |
| | FERC VRF G4 Discussion | Guideline 4- Consistency with NERC Definitions of VRFs<br>This Lower VRF is consistent with the NERC definition because the Requirement 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. |
| | FERC VRF G5 Discussion | Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation<br>The proposed Requirement has been assigned a Lower VRF, and refers to Requirement R21which has been assigned a High VRF. |
| | Proposed Lower VSL | The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator. |
| | Proposed Moderate VSL | The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator. |
| | Proposed High VSL | The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator. |
| | Proposed Severe VSL | The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator.<br>or<br>The Distribution Provider. Transmission Owner or Generator Owner did not develop its implementation plan. |
| | **FERC VSL G1**<br>Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance | The Requirements in PRC-006-1 do not address the Distribution Provider, Transmission Owner and Generator developing and submitting an implementation plan within 90 days of a request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance. |
| | **FERC VSL G2**<br>Violation Severity Level | Guideline 2a-- the VSL is not binary and does not violate this guideline. |

| | | |
|---|---|---|
| | Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties<br>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent<br>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language | Guideline 2b--the VSL does not contain ambiguous language. |
| | **FERC VSL G3**<br>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement | The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement. |
| | **FERC VSL G4**<br>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. |

**NERC's VRF Criteria:**

***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's VRF Guidelines:**
**VRF G1 – 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. From footnote 15 of the May 18, 2007 Order, FERC's list of critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System includes:

- 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.

**VRF G2 – 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.

**VRF G3 – 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.

**VRF G4 – 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.

**VRF G5 –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.

**NERC's Criteria for VSLs:**

| Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|
| The performance or product measured almost meets the full intent of the requirement. | The performance or product measured meets the majority of the intent of the requirement. | The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent. | The performance or product measured does not substantively meet the intent of the requirement. |

**FERC's VSL Guidelines:**
**VSL G1: 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.**)**

**VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties (**A violation of a "binary" type requirement must be a "Severe" VSL. Avoid using ambiguous terms such as "minor" and "significant" to describe noncompliant performance.**)**

**VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement (**VSLs should not expand on what is required in the requirement.**)**

**VSL G4: 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.)

November 4, 2011

NPCC, Inc.

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

**NPCC RSC Triage Process for Standards Related Matters**

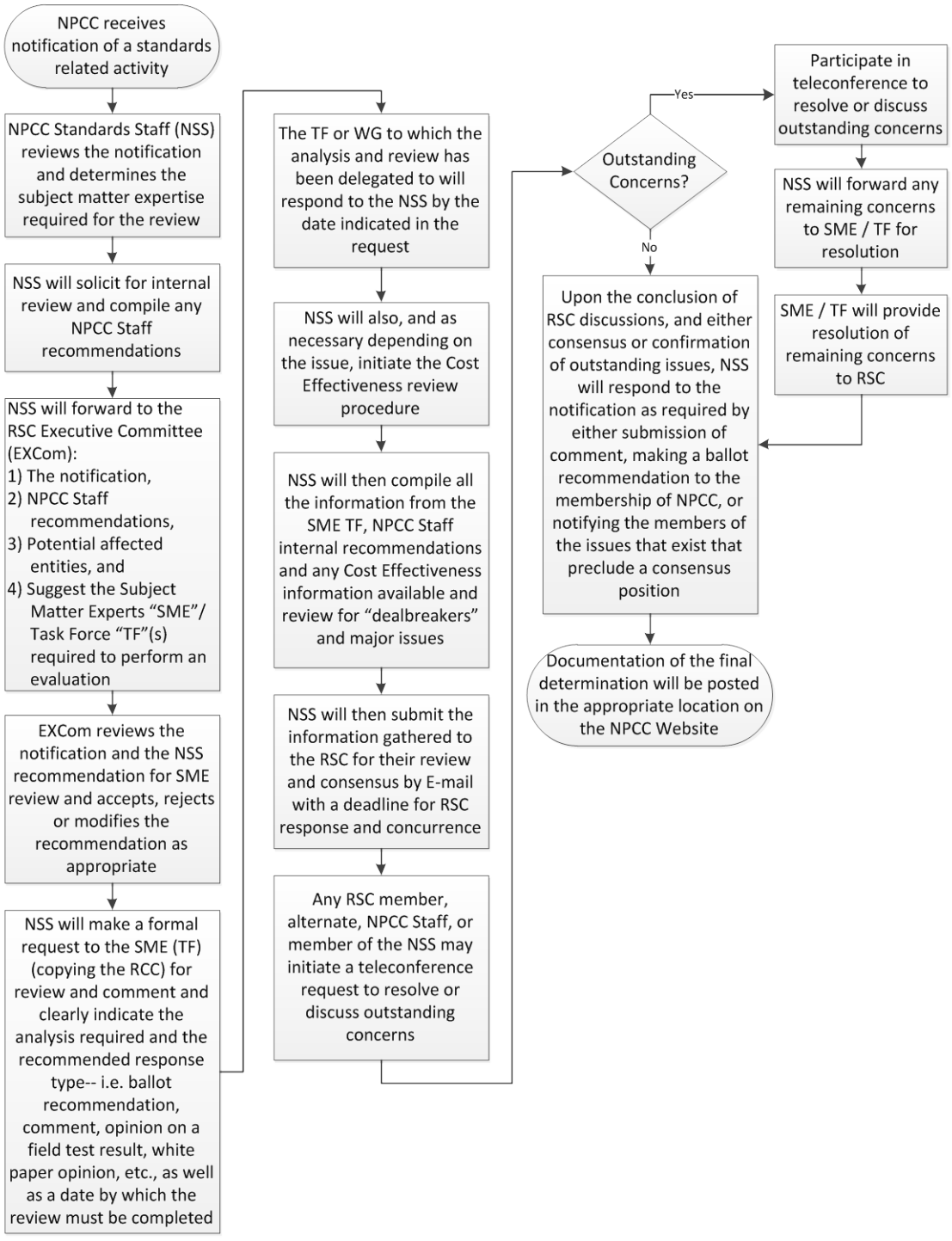
Objective: The NPCC RSC Triage Process is intended to be used to clearly identify the process that NPCC will utilize to evaluate continent-wide, regional standards and related matters. It is meant to ensure consistency, and that the proper resources are employed to review the technical subject matter and the proper policy level in order to ensure a sufficient review is done.

1) The Triage process will begin upon NPCC becoming aware of continent-wide or regional (NPCC, FRCC, etc.) standards related activity.
2) Because of the variability of deadlines for standards related activities, the NSS will develop a timeline for each activity to meet externally imposed "due dates".
3) NPCC Standards Staff (NSS) reviews the activity and determines the subject matter expertise required for the review.
4) NSS will solicit the appropriate NPCC Staff for an internal review and compile any NPCC Staff recommendations.
5) NSS will forward to the RSC Executive Committee (EXCom) the notification of the standards activity, NPCC Staff recommendations, potential affected entities, and suggest the Subject Matter Experts "SME"/ Task Force "TF"(s) required to perform an evaluation.
6) EXCom reviews the notification and the NSS recommendation for SME review and appropriately accepts, rejects or modifies (including an alternate course of action) the recommendation.
7) NSS will make a formal request to the SME (TF) (copying the RCC) for review and comment and clearly indicate the analysis required and the recommended response type-- i.e. ballot recommendation, comment, opinion on a field test result, white paper opinion, etc., as well as a date by which the review must be completed. The TF or WG to which the analysis and review has been delegated to will respond to the NSS by the date indicated in the request.
8) NSS will also, and as necessary depending on the issue, discuss with the RSC the initiation of the Cost Effectiveness review procedure.
9) NSS will then compile all the information from the SME TF, NPCC Staff internal recommendations and any Cost Effectiveness information available and review for major issues and items or requirements that should prevent the activity from being continued.
10) NSS will then submit the information gathered to the RSC for their review and consensus.
11) Any RSC member, alternate, NPCC Staff (refer to Step 4 above), or member of the NSS may initiate a teleconference request to resolve or discuss outstanding concerns.
12) As necessary any remaining concerns will be brought to the SME/TF for resolution.
13) Upon the conclusion of RSC discussions, and either consensus or confirmation of outstanding issues, NSS will respond to the notification as required by either submission of comment,

making a ballot recommendation to the membership of NPCC, or notifying the members of the issues that exist that preclude a consensus position.

14) Documentation of the final response and supporting materials will be posted in the appropriate location on the NPCC Website.

# NPCC RSC Triage Process for Standards Related Matters



NPCC, Inc.

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1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

*Approved by NPCC Board of Directors XX-XX-2012*

# Scope of Work
# for the
# Regional Standards Committee (RSC)

The NPCC Regional Standards Committee (RSC), a committee of the NPCC Board of Directors (BOD), is charged with:

(a) managing the NPCC Regional Standards Development Process.
(b) managing the NPCC Directory and Criteria Development Process.
(c) providing consolidated NPCC Regional review and comment to the existing and proposed NERC Standards and participating in the NERC Reliability Standards Development Process.
(d) reviewing the FERC Orders, Rulings and Notice of Proposed Rulemakings (NOPRs) related to reliability Standards, providing a forum for developing consensus viewpoints, and submitting comments to FERC, as necessary.
(e) reviewing NERC Compliance Application Notices (CANs) working in coordination with the NPCC Compliance Committee (CC) and submitting comments to NERC, as necessary.
(f) providing consolidated NPCC Regional review and comment to the existing and proposed NERC Standards Development Process Manual, and to the NERC Rules of Procedure as they relate to Standards Development.
(g) determining the need for and development of interpretations.
(h) providing a forum for sharing viewpoints and opinions with the goal of achieving consensus.

After receiving input from any or all NPCC groups and for all submissions of standards related comments on behalf of NPCC, the RSC will be the only body submitting those comments to FERC, NERC, or any other industry entities.

The RSC is an open and balanced stakeholder committee inclusive of all stakeholder interests that provide for or are materially impacted by the reliability of the bulk power system. The RSC meetings will be open to all stakeholders who want to participate and will be publicly posted on the NPCC Website.

Decisions of the NPCC RSC will be adopted under a sector based voting structure as described in the NPCC Amended and Restated Bylaws.

The RSC will coordinate its work through NPCC Standards Staff which will administer the NPCC Regional Standards Process and coordinate the review and submission of comments.

The RSC will be chaired by an NPCC member of Staff who will be assisted by the NPCC Regional Standards Process Manager (also a member of NPCC Staff) along with co-vice chairs elected by the RSC from the existing members of the Committee at the time the vote is taken. The co-vice chairs will serve a term of two years. The vice-chair term may be extended through a motion and subsequent vote by the committee in accordance with the NPCC Amended and Restated Bylaws.

Members of the RSC will be elected by the NPCC Board. Each of the NPCC Sectors as defined in the NPCC Amended and Restated Bylaws will be represented on the RSC.

Subcommittees and ad hoc Working Groups will be formed upon request of the RSC, by NPCC Standards program area Staff and all associated scopes or charters developed will be approved by the RSC in accordance with the most recent approved NPCC Amended and Restated Bylaws.

A. Management of the NPCC Regional Standards Process

The RSC is responsible for managing the standards process for development of standards, VRFs, VSLs, definitions, variances and interpretations in accordance with the NPCC Regional Reliability Standard Process Manual. The RSC is responsible for ensuring the quality of all Standards related materials.

The RSC will be available to advise the NPCC BOD on any standard related matters.

All RSC Regional Standard related decision making activities will be approved or rejected by a vote as outlined in the NPCC Amended and Restated Bylaws as they pertain to quorum and voting rules.

B. Management of the NPCC Directory and Criteria Process

The RSC manages and has oversight of the processes for development of NPCC Directories and Criteria. The RSC is responsible for ensuring the quality of all Directory and Criteria related materials. RSC will provide groups generating documents Quality Review guidance, and guidance on how to generate the documents.

The RSC will be available to advise the NPCC BOD on any Directory and Criteria related matters.

C. NERC Reliability Standards

The RSC will:

- Provide NPCC review and coordinate the submission of NPCC comments to existing and developing NERC Reliability Standards when posted for NERC "Open Process Review."
- Provide a forum for NPCC to participate, solicit, and provide Regional comments as new

Standard Authorization Requests (SARs), and their respective Reliability Standards, are developed in accordance with the NERC Standard Processes Manual.

- Provide a forum for NPCC to participate, solicit, and provide Regional comments from a reliability perspective on Reliability Standard Audit Worksheets (RSAW).
- Identify upcoming issues associated with new NERC Reliability Standards and their potential impact on the NPCC Region, (i.e. Regional Difference).
- Propose solutions or guide the development of the Standards through effective and timely comments and soliciting NPCC participation on the SAR and Reliability Standards drafting teams.
- Develop and maintain a Web-Based Database for tracking and scheduling Standards development activities from a Regional perspective.
- Target a wider range of participants in the standard commenting process. Develop databases and e-mail list servers to engage more members and to elicit different perspectives.
- Develop an entire process for notification, solicitation, commenting on and for proposing revisions to Standards.
- Follow up on proposed and adopted changes to the NERC Standard Processes Manual and Rules of Procedure, as they apply to Reliability Standards, and provide NPCC members with basic information (or pointers to the NERC Website) for a common understanding of the process.
- Coordinate the activities of NPCC members on standard drafting teams.
- The RSC will review draft NERC CANs for Reliability Standard and compliance implications after receiving CC input, and submit comments to NERC.

## D. FERC Activities Affecting Standards

The RSC will review FERC Orders, Rulings and Notice of Proposed Rulemakings (NOPRs) relating to Reliability Standards. The RSC will discuss, develop comments, and if necessary submit the comments to FERC on behalf of NPCC.

## Regional Approval Timelines

| Region | Process | Notification Timing | Internal Posting | Action | Exception | Enforcement Date* |
|---|---|---|---|---|---|---|
| **Ontario** | Ontario Energy Board (OEB) Remand<br><br>Ontario Electricity Act of 1998 Sect. 36.2<br><br>http://www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98e15_e.htm#BK91 | IESO receives notification of an OEB filing from NERC or NPCC (criteria) and must post on the IESO website within 7 days of this notification.<br><br>Note: Criteria refers to what is contained within either a Criteria (A) document or within the Criteria portion of a Directory document. | IESO posts Standard or Criteria on its website. | Market Participants (including the IESO) have 21 days after the posting date to apply to the OEB for a review of the Standard or Criteria. | Based on Market Participant applications or acting unilaterally the OEB can initiate a review up to 120 days after the posting date.<br><br>If the OEB determines that the Standard or Criteria unjustly discriminates against or in favor of a market participant, the OEB shall make an order that :<br><br>1. Revokes the operation of the Standard in Ontario if it is already operational or disallows any future operation of the Standard in Ontario on a date specified by the OEB.<br><br>2. Refers the Standard back to the standard authority. | The enforcement date of a NERC Standard or NPCC Criteria is governed by the Ontario Market Rules.<br><br>In accordance with Chapter #5 of the Ontario Market Rules, Standards and/or Criteria that have not been revoked and referred back to the Standard authority by the OEB, shall be considered in force within Ontario.<br><br>The enforcement date is the date that the Standard is declared in force in the United States or for NPCC Criteria when declared in force by NPCC, provided that the period for initiating a review by the OEB and the outcome of such a review has expired.<br><br>NERC Standards and NPCC Criteria shall cease to be in force when they cease to be in force in the United States.<br><br>When a Standard has not been approved by the NERC registered ballot body, but which in accordance with the NERC |

| | | | | | | |
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| | | | | | | Rules of Procedure has been approved by the NERC Board of Trustees, the Standard will not be in force in Ontario unless and until the IESO determines, in consultation with affected market participants that all or part of the Standard is in force within Ontario. In these circumstances, the IESO shall publish notice of its determination and where applicable such Standards will be in force within Ontario. |

*The date on which the standard becomes mandatory and enforceable in accordance with the existing laws of the jurisdiction and the approval granted by the regulatory authority.

## Regional Approval Timelines

| Region | Process | Notification Timing | Internal Posting | Action | Exception | Enforcement Date* |
|---|---|---|---|---|---|---|
| **Nova Scotia** | MOU between Nova Scotia Power Inc.(NSPI) NPCC and NERC (May 9, 2010)<br><br>http://www.nerc.com/files/NSUARB_NERC-NPCC-Order_20110720.pdf | NERC shall concurrently notify NSPI and the Nova Scotia Utility and Review Board (NSUARB) of Reliability Standards adopted by NERC.<br><br>NPCC shall concurrently notify NSPI and the NSUARB Regional Criteria (Directories) adopted by NPCC. | N/A. | The NSUARB will direct NSPI to review and provide comments on Standards and Criteria.<br><br>In response the NSPI will recommend either to:<br>1)Approve<br><br>2)Request Additional Information<br><br>3)Remand<br><br>NSPI will propose a timeline for the NSUARB approval of the Standard and Criteria. | | The UARB will not take any action on approving or remanding until such time as FERC has approved the Standard.<br><br>Upon approval by the NSUARB NERC Reliability Standards and NPCC Criteria will become mandatory in Nova Scotia. |

*The date on which the standard becomes mandatory and enforceable in accordance with the existing laws of the jurisdiction and the approval granted by the regulatory authority.

## Regional Approval Timelines

| Region | Process | Notification Timing | Internal Posting | Action | Exception | Enforcement Date* |
|---|---|---|---|---|---|---|
| **New Brunswick** | Market Procedure #08<br><br>Reliability Compliance Program<br><br>http://www.nbso.ca/Public/_private/MP-08.pdf | When a NERC Reliability Standard is approved by the NERC Board of Trustees and has received regulatory approval in the United States or a NPCC Criteria is approved by the NPCC Full Members the NBSO will initiate the adoption process for New Brunswick. | NBSO reviews the content and implementation plan for a Reliability Standard and develops a schedule to adopt the Reliability Standard (Criteria) as an amendment to MP -08. | Interested parties may apply to the NB Energy & Utilities Board (EUB) for a formal review.<br><br>An application made to the EUB for review does not stay the coming into effect of the Standard or Criteria on the adoption date unless otherwise directed by the EUB.<br><br>The EUB has the authority to revoke the adoption and remand it back to NBSO for further consideration. | NBSO determines that the Standard or Criteria is urgent and files with the EUB to adopt in less than 30 days. | The NBSO will post the Standard and the proposed adoption and effective dates on the NBSO Website for a 30 day review before the reliability Standard comes into effect. |

*The date on which the standard becomes mandatory and enforceable in accordance with the existing laws of the jurisdiction and the approval granted by the regulatory authority.

## Regional Approval Timelines

| Region | Process | Notification Timing | Internal Posting | Action | Exception | Enforcement Date* |
|---|---|---|---|---|---|---|
| **Quebec** | HQ-Trans Energie CME unit acts as Quebec's Reliability Coordinator (Coordinator).The Quebec RC is responsible for filing Standards with the Regie de l'energie du Quebec.<br><br>http://www.hydroquebec.com/transenergie/reliability/index.html | Pending Regie's decision. | The Reliability Coordinator submits Standards to the Regie for adoption.<br><br>http://www.hydroquebec.com/transenergie/reliability/liste_normes.html<br><br>Standards will be posted on the RC website. | The filing process of the Régie de l'énergie du Québec (http://www.regie-energie.qc.ca/en/index.html) | As determined by the Régie de l'énergie du Québec | Enforcement dates in Québec are determined by Régie's Decisions<br><br>Enforcement dates will therefore by posted on the Québec RC website |
| **United States** | | | | | | FERC approved Standards become mandatory and enforceable in the United States on a date established by the orders approving the Standards. |

The date on which the standard becomes mandatory and enforceable in accordance with the existing laws of the jurisdiction and the approval granted by the regulatory authority.

NPCC, Inc.

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July 13, 2012

**RE: Notice of Open Process Review of Draft Revised *NPCC Guide for the Application of Autoreclosing to the Bulk Power System* [B-01]**

Ladies and Gentlemen:

In accordance with the NPCC Reliability Assessment Program, the Task Force on System Protection has reviewed Document B-01 and is posting it on the NPCC Open Process Review for comments. Attached, please find a copy of the draft revised B-01 with changes highlighted. TFSP has proposed an additional definition for the term "lockout" in Section 3.11 and in Section 4.5 on Breaker Failure Operations, a minor clarifying change and an additional guidance on the coordination of autoreclosing time delay.

The NPCC Open Process Review may be accessed through:

https://www.npcc.org/Standards/SitePages/NonStandardsList.aspx

All comments must be submitted electronically through the NPCC Web site. Comments will be received for forty-five days through Monday, August 27, 2012, and they will be addressed by the NPCC Task Force on System Protection.

Thank you for your assistance.

Yours very truly,

Daren

Daren Verner, Chairman
Task Force on System Protection

Attachment

cc: Task Force on System Protection

**Document B-1**

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1515 BROADWAY, NEW YORK, NY 10036-8901 TELEPHONE: (212) 840-1070 FAX: (212) 302-2782

Draft for Open Process Review – July 13, 2012

# Guide for the Application of Autoreclosing to the Bulk Power System

Approved by the System Design Coordinating Committee and the Operating Procedure Coordinating Committee on January 29, 1979.

| | |
|---|---|
| Revised: | March 16, 1982 |
| Revised: | March 8, 1985 |
| Revised: | June 28, 1988 |
| Reviewed: | October 16, 1991 |
| Revised: | February 14, 1996 |
| Revised: | March 2, 1999 |
| Reviewed: | November 14, 2002 |
| Revised: | March 9, 2005 |
| Revised: | March 11, 2009 |

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**Notes:**

Terms in bold face type are defined in the *NPCC Glossary of Terms* (Document A-7). Italicized terms are defined in Section 3.0 of this Guideline.

**The terms autoreclosing, high-speed autoreclosing and synchronism-check** are defined in the Glossary (Document A-7). These terms are included in the definition list (Section 3.0) of this document for reference only, in order to make the document easier to read.

## 1.0 Objectives

The purpose of this document is to establish guidelines for the application of **autoreclosing** facilities to circuit breakers on the NPCC **bulk power system**. This document is not intended to provide guidance for the operation of the **bulk power system** in matters of **reclosing**, such as enabling or disabling **autoreclosing** or providing for *manual* closures following *automatic* tripping of an **element**.

## 2.0 Introduction

**Autoreclosing** should be applied for the purpose of restoring transmission lines to service subsequent to *automatic* tripping of their associated circuit breakers due to electrical **faults**. Experience of the NPCC member companies indicates that many **faults** on the bulk power overhead transmission system are temporary. In the absence of **autoreclosing**, longer duration **outages** could be experienced unnecessarily. Successful **autoreclosing** can enhance **stability** margins and overall system **reliability**. However, **autoreclosing** into a permanent **fault** may adversely affect system **stability**, hence due consideration must be given to this aspect of any application.

## 3.0 Definitions

3.1 **Autoreclosing*** is 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.

3.2 *Breaker **reclosing** time* is the elapsed time between the energizing of the breaker trip coil and the closing of the breaker contacts to reestablish the circuit by the breaker primary contacts on the **reclose** stroke.

3.3 **High-speed autoreclosing*** refers to 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.

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* See note on Table of Contents Page

3.4 *Delayed autoreclosing* refers to the **autoreclosing** of a circuit breaker after a time delay which is intentionally longer than that for **high-speed autoreclosing**.

3.5 **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.

3.6 *Multiple-shot **autoreclosing*** refers to the **autoreclosing** of the circuit breaker(s) more than once within a predetermined **reclosing** sequence.

3.7 *Blocking* refers to the *automatic* prevention of an action following specific **relay** tripping operations.

3.8 *Single-pole **autoreclosing*** refers to the **autoreclosing** of one pole of a circuit breaker following a designed single-pole trip for single-phase-to-ground **faults**.

3.9 *Manual* refers to either local or remote switching operations that are initiated by an operator.

3.10 *Automatic* refers to either local or remote switching operations that are initiated by **relay** or control action without the direct intervention of an operator.

3.11 *Lockout* refers to the complete disabling of the reclosing sequence until reset.

## 4.0 Common Considerations to High-Speed and Delayed Autoreclosing

4.1 *Blocking* of **Autoreclosing**

**Autoreclosing** should be blocked during the reception of a direct transfer trip signal. **Autoreclosing** should be blocked, or not be initiated, following any *manual* operation of a circuit breaker.

4.2 Turbine-Generator Considerations

*Manual* closing or **autoreclosing** at line terminals that are in electrical proximity to turbine-generators may subject them to excessive shaft torques and winding stresses with resultant loss of life of the turbine-generator system. These effects should be studied and evaluated before **autoreclosing** is applied. It is preferable to re-**energize** a line at a terminal remote from the generator bus, and then **autoreclose** or close at the generator end. The **autoreclosing** at the generator end may be supervised by **synchronism-check** function.

* See note on Table of Contents Page

4.3 Circuit Breaker Capability

The design and implementation of **autoreclosing** system should consider the circuit breaker capability. **Autoreclosing** times and sequences should be selected with due regard to circuit breaker interrupting capability, duty cycle, derating, voltage withstand capability, resistor thermal capability, and overall breaker design.

4.4 Number of Operations

*Multiple-shot **autoreclosing*** systems should be designed considering the breaker operating time, available air or gas pressure for breaker operation, and **system stability** margins.

4.5 Breaker Failure Operations

**Autorelosing** time delay should be coordinated with breaker failure trip time.

**Autoreclosing** following breaker failure operation ~~is not recommended~~should not occur until the failed breaker is isolated.

4.6 Other System **Elements**

Risks versus benefits should be evaluated before applying **autoreclosing** following **faults** on transformers, enclosed busses, **cables**, etc. For this type of system **elements**, it is generally not advisable to **autoreclose** since the probability of a **fault** being permanent is high and the probability of aggravating equipment damage is increased. Under specific circumstances, however, the benefits of **autoreclosing** may justify its use.

Caution also should be taken when applying **autoreclosing** following **faults** on lines that terminate with or include transformers, enclosed busses, **cables**, etc. In these situations the same precautions should be applied unless means are provided to differentiate between **faults** on the line from **faults** on the transformer, enclosed bus, or **cable**, and to supervise **autoreclosing**.

4.7 Multiple Circuit Breaker Line Termination

The recommended mode of **autoreclosing** at a terminal with more than one breaker per line is to **autoreclose** with a preselected breaker. Following successful **autoreclose** operation, the other breaker(s) associated with the line at that terminal may be **autoreclosed**. Since

simultaneous closing of two or more breakers is difficult to achieve, **autoreclosing** into a permanent **fault** by more than one breaker at the same line terminal could result in the **fault** being maintained on the system for a longer than intended period, and may be followed by an incorrect breaker failure operation for certain relay designs. In addition, the severity of the system **disturbance** may be increased.

4.8 Line Connected Shunt Capacitor

It is preferable that **reclosing** of line circuit breakers be completed before closing (normally by operator action) the shunt capacitor breaker.

## 5.0 High-Speed Autoreclosing Considerations

5.1 Tripping Requirements

**High-speed autoreclosing** should be initiated only if all terminals of the line are tripped without intentional time delay for line **faults**.

5.2 **Stability** Considerations

When **high-speed autoreclosing** is under consideration as a means for increasing the **transient stability** margin of a system, restoring service to critical **loads**, or restoring needed system interconnections, it should be recognized that there is a risk as well as a possible benefit associated with its use. The risk is that **stability** may be endangered rather than benefited if a line is **autoreclosed** into a permanent **fault**. **Stability** studies should indicate whether or not the use of **high-speed autoreclosing** should be restricted.

5.3 Out-of-Step Conditions

Since **high-speed autoreclosing** is generally unsupervised, it should be *blocked* following an out-of-step **relay** operation.

5.4 Switching **Surge** Considerations

**High-speed autoreclosing** should not be used where transient voltage analysis studies indicate that **high-speed autoreclosing** may produce switching **surge** magnitudes exceeding the equipment design levels.

## 6.0 Delayed Autoreclosing Considerations

6.1 General Use

**Delayed autoreclosing** may be used following design analysis and may be preferable to **high speed autoreclosing**.

6.2 Frequency, Phase Angle and Voltage Considerations

**Synchronism-check relays** should be used where analysis shows that for credible system conditions there may be harmful effects on the system due to excessive frequency differences, phase angles, or voltage magnitudes across the closing breaker. When applying **synchronism-check relays** appropriate consideration should be given to avoiding unnecessary restriction of breaker **autoreclosing** or *manual* closing following major system **disturbances**. It may be necessary to employ means to ensure undesired **autoreclosing** modes do not take place. For example, dead-line **supervision** of **autoreclosing** or *manual* closing may be used where harmful effects on the system would result from connection of **energized** facilities.

6.3 **Autoreclosing** Time Considerations

A time delay should be used, as determined by **stability** studies, to allow damping of system oscillations following a **disturbance**. If **stability** studies are not available, a 15-second time delay appears to be conservative for most systems.

Following the initiation of an **autoreclosing** sequence, **autoreclosing** attempts should be prevented after a predetermined time period. This time period should not prohibit completion of the **autoreclosing** sequence and must include circuit breaker **fault clearing** time, **synchronism-check** timing and **protective relay** and control system response times. To prevent unexpected operation, the **autoreclosing** sequence must be completed or go to a lockout state prior to the commencement of operator-initiated switching. Re-arming of the **autoreclosing** scheme may be achieved by automatic, manual or remote methods.

---

Prepared by: Task Force on System Protection.

Review frequency: 3 years

Reference: *NPCC Glossary of Terms* (Document A-7)

## Regional Approval Timelines

| Region | Process | Notification Timing | Internal Posting | Action | Exception | Enforcement Date* |
|---|---|---|---|---|---|---|
| **Ontario** | Ontario Energy Board (OEB) Remand<br><br>Ontario Electricity Act of 1998 Sect. 36.2<br><br>http://www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98e15_e.htm#BK91 | IESO receives notification of an OEB filing from NERC or NPCC (criteria) and must post on the IESO website within 7 days of this notification.<br><br>Note: Criteria refers to what is contained within either a Criteria (A) document or within the Criteria portion of a Directory document. | IESO posts Standard or Criteria on its website. | Market Participants (including the IESO) have 21 days after the posting date to apply to the OEB for a review of the Standard or Criteria. | Based on Market Participant applications or acting unilaterally the OEB can initiate a review up to 120 days after the posting date.<br><br>If the OEB finds that the Standard or Criteria unjustly discriminates against or in favour of a market participant or class of market participants, the OEB shall make an order,<br>(a) *revoking the operation of the standard in Ontario, if it is already operational, or disallowing the future operation of the standard in Ontario, on a date specified by the Board; and<br>(b) *referring the standard back to the standards authority for further consideration.~~If the OEB determines that the Standard (Criteria) unjustly discriminates it can remand the Standard or Criteria back to either NERC or NPCC.~~ | The enforcement date of NERC Standard or NPCC Criteria is governed by the Ontario Market Rules.<br><br>According to Chapter 5~~, sections 1.2.6 and 1.2.7~~ of the Ontario Market Rules, NERC Standards or NPCC Criteria that have not otherwise been stayed or revoked and referred back to the standards authority for further consideration by the OEB shall be declared in force in Ontario:<br>(a) *when the reliability standards are declared in force in the United States or, for NPCC reliability criteria, when declared in force by NPCC; and<br>(b)* after the expiry of the period for initiating a review by the OEB and the conclusion of any such review.<br><br>NERC Standards and NPCC Criteria shall cease to be in force in Ontario when they cease to be in force in the United States.<br><br>When a reliability standard approved by the NERC BoT failed to achieve approval by the NERC registered |

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| | | | | | | ballot body as specified in NERC's Rules of Procedure, the reliability standard will not be in force in Ontario unless and until the IESO determines, in consultation with affected market participants, that all or part of the reliability standard is in force in Ontario. The IESO shall publish notice of its determination and where applicable, such reliability standard will come into effect ~~in accordance with Chapter 5, section 1.2.6 of the Ontario Market Rules.~~<br>~~Standards that the OEB has not remanded are declared in force within Ontario when the Standard is declared in force within the United States (FERC approval) in accordance with Chapter 5 sections 1.2.6 and 1.2.7 of the Ontario Market Rules.~~<br><br>~~Similarly, if the OEB has not remanded NPCC Criteria, the Criteria are declared in force within Ontario upon NPCC Full Member approval.~~<br><br>~~In the circumstance of a Standard approved by NERC that was not approved by the NERC Ballot Body, the Standard will not be in force until the IESO determines in consultation with affected market participants that all or part of the Standard is in force in Ontario.~~ |

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*The date on which the standard becomes mandatory and enforceable in accordance with the existing laws of the jurisdiction and the approval granted by the regulatory authority.

## Regional Approval Timelines

| Region | Process | Notification Timing | Internal Posting | Action | Exception | Enforcement Date* |
|---|---|---|---|---|---|---|
| **Nova Scotia** | MOU between Nova Scotia Power Inc.(NSPI) NPCC and NERC (May 9, 2010)<br><br>http://www.nerc.com/files/NSUARB_NERC-NPCC-Order_20110720.pdf | NERC shall concurrently notify NSPI and the Nova Scotia Utility and Review Board (NSUARB) of Reliability Standards adopted by NERC.<br><br>NPCC shall concurrently notify NSPI and the NSUARB Regional Criteria (Directories) adopted by NPCC. | N/A. | The NSUARB will direct NSPI to review and provide comments on Standards and Criteria.<br><br>In response the NSPI will recommend either to:<br>1)Approve<br><br>2)Request Additional Information<br><br>3)Remand<br><br>NSPI will propose a timeline for the NSUARB approval of the Standard and Criteria. | | The UARB will not take any action on approving or remanding until such time as FERC has approved the Standard.<br><br>Upon approval by the NSUARB NERC Reliability Standards and NPCC Criteria will become mandatory in Nova Scotia. |
| **Quebec** | HQ-Trans Energie CME unit acts as Quebec's Reliability | Pending Regie's decision. | The Reliability Coordinator submits Standards to the Regie for adoption. | The filing process of the Régie de l'énergie du Québec | As determined by the Régie de l'énergie du Québec | Enforcement dates in Québec are determined by Régie's Decisions |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Coordinator (Coordinator). The Quebec RC is responsible for filing Reliability Stds. with the Regie de l'energie du Quebec.<br><br>http://www.hydroquebec.com/transenergie/reliability/index.html | | http://www.hydroquebec.com/transenergie/reliability/liste_normes.html<br><br>Standards will be posted on the RC website. | (http://www.regie-energie.qc.ca/en/index.html) | | Enforcement dates will therefore by posted on the Québec RC website |

## Regional Approval Timelines

| Region | Process | Notification Timing | Internal Posting | Action | Exception | Enforcement Date* |
|---|---|---|---|---|---|---|
| **New Brunswick** | Market Procedure #08<br><br>Reliability Compliance Program<br><br>http://www.nbso.ca/Public/_private/MP-08.pdf | When a NERC Reliability Standard is approved by the NERC Board of Trustees and has received regulatory approval in the United States or a NPCC Criteria is approved by the NPCC Full Members the NBSO will initiate the adoption process for New Brunswick. | NBSO reviews the content and implementation plan for a Reliability Standard and develops a schedule to adopt the Reliability Standard (Criteria) as an amendment to MP -08. | Interested parties may apply to the NB Energy & Utilities Board (EUB) for a formal review.<br><br>An application made to the EUB for review does not stay the coming into effect of the Standard or Criteria on the adoption date unless otherwise directed by the EUB.<br><br>The EUB has the authority to revoke the adoption and remand it back to NBSO for further consideration. | NBSO determines that the Standard or Criteria is urgent and files with the EUB to adopt in less than 30 days. | The NBSO will post the Standard and the proposed adoption and effective dates on the NBSO Website for a 30 day review before the reliability Standard comes into effect. |
| **United States** | | | | | | FERC approved Standards become mandatory and enforceable in the United States on a date established by the orders approving the |

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|---|---|---|---|---|---|---|
| | | | | | | Standards. |

*The date on which the standard becomes mandatory and enforceable in accordance with the existing laws of the jurisdiction and the approval granted by the regulatory authority.

# Implementation Plans

**(The initial date of this Implementation Plan is June 26th, 2009)**

## UFLS Implementation Plan for the Eastern Interconnection Portion of NPCC

| END OF YEAR | CONVERSIONS/MODIFICATIONS | ORIGINAL REMAINING | TOTAL | REMARKS |
|---|---|---|---|---|
| 0 | | | 10% - 59.3 Hz<br>15% - 58.8 Hz | |
| 1 | 7% of the 10% block to 59.5 Hz | 3% - 59.3 Hz<br>15% - 58.8 Hz | 7% - 59.5 Hz<br>3% - 59.3 Hz<br>15% - 58.8 Hz | Setting changes only. Total clearing time of 300 ms can be implemented if possible |
| 2 | • 4% of the 15% block to 59.3 Hz<br>• 3% of the 15% block to 59.1 Hz | 3% - 59.3 Hz<br>8% - 58.8 Hz | 7% - 59.5 Hz<br>7% - 59.3 Hz<br>3% - 59.1 Hz<br>8% - 58.8 Hz | Setting changes only. Leave original 3% at 59.3 Hz. Total clearing time of 0.3 seconds can be implemented if possible |
| 3 | • 4% of the 15% block to 59.1 Hz<br>• 3% of the 15% block to 58.9 Hz<br>• Add UFLS capacity of 2% at 58.9 Hz with total time delay of 0.3 sec. | 3% - 59.3 Hz<br>1% - 58.8 Hz | 7% - 59.5 Hz<br>7% - 59.3 Hz<br>7% - 59.1 Hz<br>3% - 58.9 Hz<br>2% - 58.9 Hz (fast)<br>1% - 58.8 Hz | 1st year of adding 2% portion of the new UFLS capacity. New capacity will have total clearing time of 300 ms.<br>1st year of decreasing total time if not already done so. Clearing time changes must be implemented if not done already in year 1 and 2 |
| 4 | • 1% of the 15% block to 58.9 Hz<br>• Change time of 1st block (59.5 Hz) to total of 0.3 sec.<br>• Add UFLS capacity of 1% at 58.9 Hz with total time delay of 0.3 sec<br>• Add UFLS capacity of 2% Anti-stall block at 59.5 Hz with total time delay of 10 sec | | 7% - 59.5 Hz (fast)<br>7% - 59.3 Hz<br>7% - 59.1 Hz<br>3% - 58.9 Hz<br>4% - 58.9 Hz (fast)<br>2% - 59.5 Hz (10 s) | Adding anti-stall block. |
| 5 | • Change time of 2nd block (59.3 Hz) to total of 0.3 sec. | | 7% - 59.5 Hz (fast)<br>7% - 59.3 Hz (fast)<br>7% - 59.1 Hz<br>3% - 58.9 Hz<br>4% - 58.9 Hz (fast)<br>2% - 59.5 Hz (10 s) | Continue with time delay changes |
| 6 | • Change time of 3rd block (59.1Hz) to total of 0.3 sec.<br>• Change time of remaining 4th block (58.9 Hz) to total of 0.3 sec | | 7% - 59.5 Hz (fast)<br>7% - 59.3 Hz (fast)<br>7% - 59.1 Hz (fast)<br>7% - 58.9 Hz (fast)<br>2% - 59.5 Hz (10 s) | Program complete. |

1. All percentages are approximate.
2. Conversions and modifications are to be dispersed geographically throughout an Area, as much as practical.
3. All conversions include the modifications necessary to achieve a total clearing time (UFLS relay operating time, aux relay time, and breaker time) of 300 ms. The 300 ms total clearing time can be taken

as an average value. The regional standard could be written to require an average total clearing time plus or minus some standard deviation, such as 50 ms.

4. A minimum UFLS relay operating time shall not be less than 100 ms.
5. Final percentages of recommended program will be the end of year 6.
6. Transmission Owners and Distribution Providers with a peak load of $\leq$ 100 MW and who were initially granted a deferment from this implementation plan by their Balancing Authority shall implement the changes as prescribed in Sections 5.2.2 and 5.2.3 of Directory #12 within 36 months of the date that Directory #12 is revised to include these sections.

## UFLS Implementation Plan for the Québec Interconnection Portion of NPCC

1. Revision to existing relay settings is expected to be completed by the end of year 2.
2. Relay addition to complete the recommended program stages will be finalized by the end of year 3.

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
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# NPCC
# Regional Reliability Reference Directory # 3
# Maintenance Criteria for Bulk Power System Protection

| Task Force on System Protection Revision Review Record: |
|---|
| **July 11, 2008** |
| **June 30, 2009** |
| |

Adopted by the Members of the Northeast Power Coordinating Council, Inc. this July 11, 2008 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** | **7/11/08** | | **New** |
| **1** | **6/30/09** | **Revised Section 5.5, Sect 5.6, and Sect 5.7.** | **Revisions** |
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Appendix A

Appendix B

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# 1.0 Introduction

## 1.1 Title

Maintenance Criteria for BPS Protection

## 1.2 Directory Number

3

## 1.3 Objective

The purpose of this Directory is to present the basic maintenance requirements for **bulk power system protection systems**. It is recognized that responsible entities may choose to apply more rigid requirements because of local considerations.

## 1.4 Effective Date

July 11, 2008

## 1.5 Background

This Directory was developed from the NPCC A-04 Maintenance Criteria for Bulk Power System Protection and B-23 Guideline document. Guidelines and procedures for consideration in the implementation of this Directory are provided in Appendix B.

## 1.6 Applicability

### 1.6.1 Functional Entities[1]

Transmission Owners
Generator Owners
Distribution Providers

### 1.6.2 Facilities

These criteria shall apply to all **protection** of the NPCC **bulk power system**, including Type I **special protection systems** and **protection** required for the NPCC Automatic Underfrequency **Load Shedding** Program.

Automatic underfrequency **load shedding protection systems** and generator underfrequency tripping **relays** are not generally located at **bulk power system** stations; however, they have a direct effect on the operation of the **bulk power system** during major **emergencies**, and as such, they are subject to these criteria.

[1] Any of these entities that own a transmission protection system and/or a Underfrequency Load Shedding (UFLS) facility/program

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## 2.0 Terms Defined in this Directory

The definitions of terms found in this Directory appearing in bold typeface can be found in Document A-07, NPCC Glossary of Terms.

## 3.0 NERC Reliability Standard Requirements

The NERC Reliability Standards containing Requirements that are associated with this Directory include:

3.1 PRC-005-1 – Transmission and Generation Protection System Maintenance and Testing
3.2 PRC-008-0 - Implementation and Documentation of UFLS Equipment Maintenance Program
3.3 PRC-011-0 – UVLS System Maintenance and Testing
3.4 PRC-012-0 – Special Protection System Review Procedure
3.5 PRC-017-0 – Special Protection System Maintenance and Testing

## 4.0 NPCC Regional Reliability Standard Requirements

None developed at this time.

## 5.0 NPCC Full Member, More Stringent Requirements

### 5.1 General Criteria

Minimum periodic testing of each **protection group** shall be conducted to verify that the **protection group** is capable of performing its intended **protection** function. Such testing shall include **protection** assembly testing (as illustrated in attached Figure 1) and **protection group** system testing. To assure satisfactory operation of the protective equipment as a system, test procedures and test facilities must ensure that related tests properly overlap.

### 5.2 **Protection** Assembly Testing Requirements

Refer to Figure 1, equipment marked as [1]

The following **Protection** Assembly testing shall be performed on an interval not exceeding that specified in Table 1 for **bulk power system protection groups**:

5.2.1 Make visual inspections,

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5.2.2 Verify inputs and outputs,

5.2.3 Confirm that the intended version of software is installed (microprocessor-based **relays**),

5.2.4 Verify correct **protection** operation,

5.2.5 Verify the integrity of current and voltage transformers and associated circuitry. This verifies that the correct secondary quantities are input to the **relay**. For microprocessor **relays**, verify the internal analog inputs with an independent source.

**TABLE 1**
**INTERVALS FOR PROTECTION ASSEMBLY TESTING**

| | Non-Self Monitored **Protection Assembly** Note (1) | Microprocessor-Based **Protection Assembly** Note (2) | Microprocessor-Based **Protection Assembly** Note (3) |
|---|---|---|---|
| All **Protection Groups** | **4 years** | **6 years** | **8 years** |

Notes:

(1) Non-Self Monitored **protection** assemblies include electromechanical **relays** and solid state **relays**.

(2) Microprocessor-based **protection** assemblies where the principal fault-sensing and logic components include self monitoring or self checking, and the failure alarm is annunciated to a 24/7 staffed Operations Center that can initiate an investigation of the problem.

(3) Microprocessor-based **protection** assemblies as per Note (2), plus additional self monitoring or self checking of ac voltage and current input integrity, and the failure alarm is annunciated to a 24/7 staffed Operations Center that can initiate an investigation of the problem.

5.3 **Protection Group** DC Circuits Testing Requirements

Refer to Figure 1, equipment marked as [2]

Tests performed in Section 5.2 above verify the operation of the ac signaling, measuring **relays,** and verify a **protection** assemblies' ability to initiate a trip output(s). However, to verify operation of the **protection group** as a system, DC circuit testing is required. These tests verify the **protection** equipment operation from the trip outputs of the protection

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assembly up to breaker trip coils. DC circuit testing can be achieved by verifying overlapping **protection group** equipment zones, normally bound by test switches, or by test tripping the **protection group.**

DC circuit test tripping shall be performed on an interval not exceeding that specified in Table 2 for **bulk power system protection groups**:

**TABLE 2**
**INTERVALS FOR DC CIRCUIT TEST TRIPPING**

| | Non-Monitored | Monitored Note (1) |
|---|---|---|
| DC Circuit Tripping | 4 years | 6 years |

Note (1): Trip coil and DC circuit continuity is annunciated upon loss of continuity to a 24/7 staffed Operations Center that can initiate an investigation of the problem**.**

5.4 Battery Banks and Chargers Testing Requirements

Refer to Figure 1, equipment marked as [5]

Voltage verification of the station battery bank(s) shall be performed on an interval not exceeding that specified in Table 3 for **bulk power system protection groups**:

**TABLE 3**
**INTERVALS FOR BATTERY BANKS AND CHARGER TESTING**

| | Non-Monitored | Monitored Note (1) |
|---|---|---|
| Battery Bank Voltage | One month | None |

Note (1): Battery Bank Voltage alarms are annunciated to a 24/7 staffed Operations Center that can initiate an investigation of the problem**.**

5.5 Breaker Trip Testing Requirements

Refer to Figure 1, equipment marked as [4]

The ability of the breaker(s) to trip via each trip coil shall be verified every two years with the following exception. Nuclear plant **bulk power system** unit breaker trip tests shall be completed at an interval not to exceed three years.

5.6 Telecommunication Testing Requirements

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Refer to Figure 1, equipment marked as [3a] and [3b]

5.6.1 Terminal Equipment

Telecommunications terminal equipment shall be tested on the same time interval as the protection assemblies as per Table 1 above.

5.6.2 Channel Health

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.

For trip equipment which uses frequency shift keying (FSK) mode of communication and the channel (for example, Guard Signal) is continuously monitored, the ability to perform its intended trip function shall be verified every twelve months. Failure of the channel shall be annunciated to a 24/7 staffed Operations Center that can initiate an investigation of the problem.

For telecommunication system channels that are continuously monitored and continuously provide verification of trip capability to an Operator, no additional testing is necessary. Failure of the channel or of the trip capability shall be annunciated to a 24/7 staffed Operations Center that can initiate an investigation of the problem.

5.7 Underfrequency Load Shedding and Generator Underfrequency Relay Testing Requirements

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 Underfrequency **Load Shedding** Program.

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5.7.2 The successful operation of the NPCC Automatic Underfrequency **Load Shedding** Program requires the proper coordination of generator underfrequency tripping, as described in Directory 2. For generators rated 20 MW and above, the correct calibration of generator underfrequency tripping **relays** shall be verified at an interval not exceeding that specified in Table 1.

6.0 Measures and Assessments

None developed at this time.

7.0 Compliance Monitoring

Adherence to requirements in this Directory must be reported in a manner and form designated by the Compliance Committee. Exceptions to the requirements stipulated herein are acceptable if the exceptions are completely removed within five (5) months of the end of the calendar year in which the testing is due. The intervals specified in this document refer to calendar year in which testing is due regardless of the date.

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Prepared by: 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.

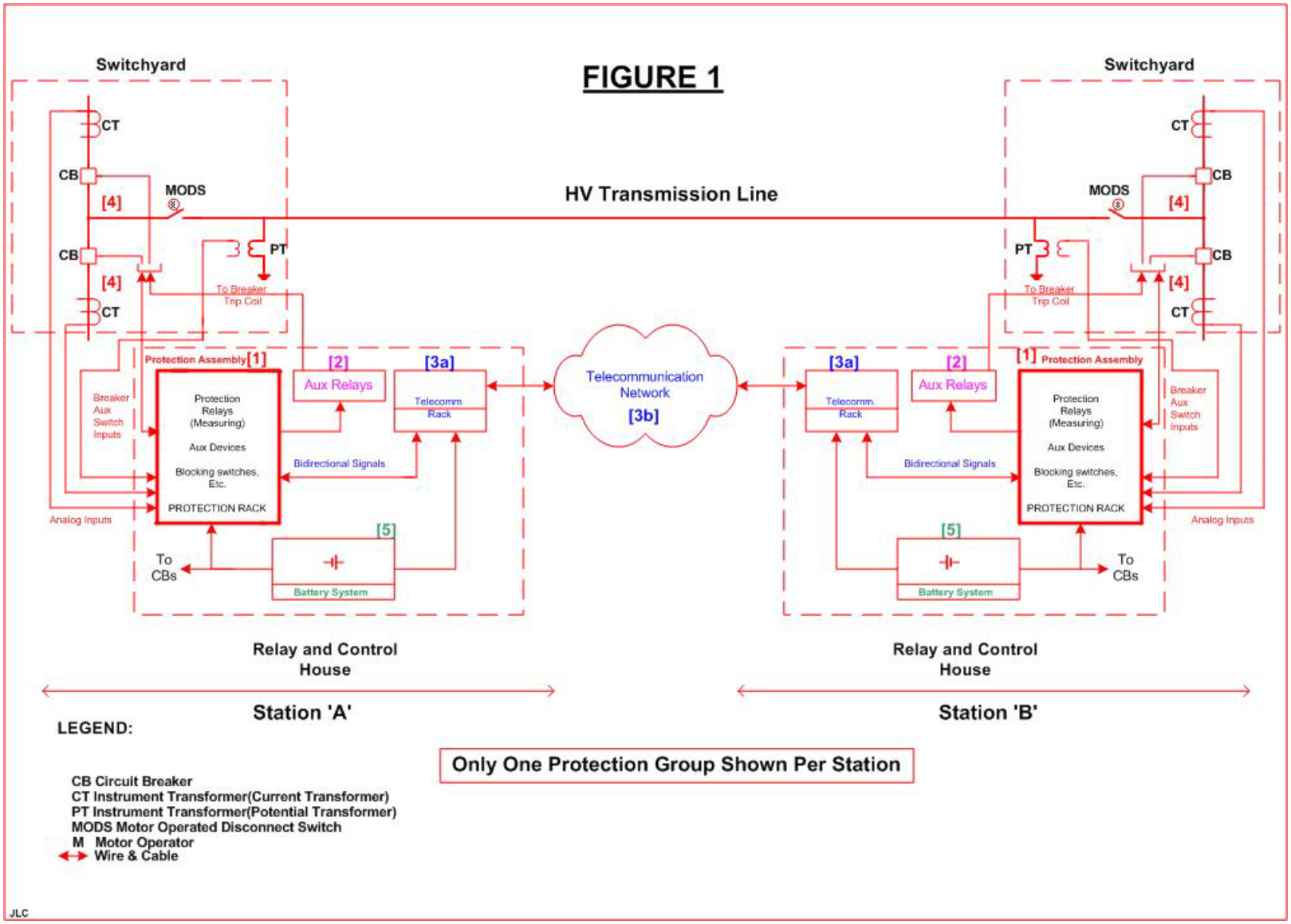
Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the 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 3 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)

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# Appendix A
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.

**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.

**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.

**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.**

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**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.

**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**).

**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**

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# Appendix B
# Guideline and Procedure for Maintenance of Bulk Power System Protection

## 1.0 Introduction

This Appendix provides the guidelines and procedures for consideration in the implementation of this Directory.

## 2.0 General

### 2.1 Generator Under-frequency Tripping

For generators rated less than 20 MW, consideration may be given to verifying the calibration of generator underfrequency **relays** at an interval not exceeding that specified in Table 1.

### 2.2 Circuit Breaker Trip Testing

Credit can be obtained for normal breaker operations if the equipment design permits verification and documentation of breaker tripping by each individual trip coil.

## 3.0 Microprocessor-based Protective Relays

The use of computer based technology for **protective relays** has influenced what is considered sufficient for periodic maintenance of microprocessor-based **relays**. The purpose of this document is to provide guidance for the maintenance of microprocessor-based **protective relays** as required in Section 5.2 and in notes (2) and (3) of Table 1 of this Directory.

This Section applies only to the maintenance of microprocessor-based **protective relays** (**Protection** Assembly Testing Requirements verify correct **protection** operation). It does not include other **protection** maintenance that is still required, as outlined in the remaining Sections of this Directory.

This Section is not intended to be a maintenance procedure, but rather a guide for member systems to develop their maintenance procedures.

### 3.1 Testing of Microprocessor-Based Relays

For the purposes of maintenance testing, microprocessor-based **relays** or Intelligent Electronic Devices (IEDs), can be viewed as being composed of four sections:

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3.1.1 Analog Input Section;
3.1.2 Digital Input/Output Section;
3.1.3 Processor Section; and;
3.1.4 Power supply Section

3.2 Analog Input Section

Measurements of magnitude and angle (calculate where not available directly) of metered values should be compared with known quantities. This supposes that the device uses the same hardware for both protection and metering. If this is not the case, then a calibration test should be conducted to verify the analog inputs.

It is not sufficient to compare the magnitudes as measured by the IED. The input section has filtering with active and passive components, which are vulnerable to change over time and cause changes in the phase characteristics of the channel. Measuring and recording of the phase angle readings is, therefore, required.

3.3 Digital Input and Output Sections

Each digital input and output that is utilized should be verified for proper functions.

3.3.1 Inputs

Operation of all used physical inputs should be verified by applying the DC control voltage, and observing associated display, or the computer interface.

3.3.2 Outputs

Outputs of the IED should be verified either by:

3.3.2.1 Asserting the output element using appropriate relay commands and observe the status of the output relay, or;

3.3.2.2 Where such features are not available, the appropriate output contact can be verified by asserting the associated logic settings that permit contact operation.

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3.4 Processor Section

The processor section samples the analog and digital inputs, executes the algorithm and logic, and provides the outputs. It includes program memory, non-volatile memory for settings and volatile memory for sequence of events and oscillography. The processor section also performs self-checking.

All of the downloaded settings and the firmware version should be compared with the official copy of the protection settings to verify that the **relay** contains the intended settings, and it is working with the intended version of firmware.

3.5 Power Supply Section

Most microprocessor-based IEDs provide measurement of the power supply voltages and/or continuously monitor the power supply voltages, and provide a **relay** failure alarm if they go out of limits. Where these values are accessible, they should be checked against specified ranges. Alternatively, the alarm should be checked on loss of dc voltage to the power supply.

3.6 Integrity Testing

This test is intended to verify the integrity of operation of the **relay** program execution and the processing of the phase voltages and current signals. Verify the correct operation of one of the three-phase protection elements, or a single phase, for a single-phase **relay**. As an example, for a distance **relay**, test one of a zone's A-G, B-G, and C-G elements.

3.7 Multi-Processor Based IEDs

Most **relays** are designed using a single processor; however, some **relay** designs use multiple processors. If the processing is divided among several processors, then tests should be conducted to include testing of functions that are executed in the respective processors. The manufacturer and/or manual should be consulted to verify hardware configuration. As an example, if a **relay** uses two processors, one each for phase and ground elements, then integrity testing should be repeated for phase and ground elements respectively.

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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<br>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** |
| |

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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. .

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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**.

<u>NPCC Specific Definitions:</u>

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.

# NPCC Task Force on Coordination of Operation
# Final Minutes of the Conference Call of June 6, 2012-2:00 PM EDT

**In attendance:**

| | |
|---|---|
| Dwayne Basler* | Northeast Utilities |
| James D. Castle* | New York ISO |
| David A. Daley* | New Brunswick System Operator |
| **Chair** | |
| Gerard J. Dunbar | Northeast Power Coordinating Council, Inc. |
| Leonard Kula* | Independent Electricity System Operator |
| Richard Mailhot* | Hydro-Québec TransÉnergie |
| John G. Mosier, Jr. | Northeast Power Coordinating Council, Inc. |
| John Norden* | ISO New England Inc. |
| **Vice Chair** | |
| Michael Schiavone* | National Grid |
| David Stanford* | Nova Scotia Power Incorporated |
| Daniel Taft | Consolidated Edison Company of New York, Inc. |
| Paul Tremblay* | Hydro One |

* voting TFCO member or designated proxy

**Proposed Increase in SAR Participation by the New Brunswick System Operator**

Mr. Daley and Mr. Norden advised the Task Force on Coordination of Operation that the Potential SAR allocation for the New Brunswick System Operator would increase from 50 MW to 100 MW. Mr. Daley explained that transmission limitations in Northern New England and on the New Brunswick-New England interface had previously constrained New Brunswick participation to no more than 50 MW. The addition of the second New Brunswick to New England interconnection, together with transmission enhancements in northern New England, now permitted the increase of New Brunswick participation to 100 MW. It was also pointed out that the participation of 100 MW could flow in either direction between New Brunswick and New England. Mr. Daley also pointed out that no NPCC documentation identified the 50 MW limit on the part of the NBS so participation.

Mr. Daley noted that email solicitations to the TFCO asking if there were any operational concerns on the part of any Task Force member had indicated acceptance of the proposal. He also noted that PJM had accepted the increase from 50 MW to 100 MW.

Following this discussion, the TFCO acknowledged that there were no operational concerns with the increase in the NBSO SAR participation from 50 MW to 100 MW and accepted the proposal.

**Request for Document Interpretation by the Regional Standards Committee (RSC)**

Mr. Mosier explained that the RSC had directed a request for interpretation of NPCC Regional Reliability Reference Directory 8, "System Restoration." The process is a recently instituted program in which the RSC directs the request for interpretation to the appropriate NPCC subject matter experts. He explained that the request for interpretation placed before the TFCO was the first such request conducted under this program. The request for interpretation was made by the New York state reliability Council concerning section 5.7.2.1 of Directory 8. As the parent Working Group for Directory 8, the Restoration Working Group (CO-11) initially addressed the request and provided a draft response for the consideration of the TFCO.

Following further revisions of the proposed draft CO-11 reply to the New York State Reliability Council, the TFCO approved the response for submission to the Regional Standards Committee. Mr. Dunbar will in turn submit the interpretation to the NYSRC.

**Ongoing Review of NPCC Regional Reliability Reference Directory 1, "Design and Operation of the Bulk Power System,"**

Mr. Doran, NPCC consultant, joined the call to direct the review of Directory 1. He noted a major concern in the document was the treatment of a single line to ground fault when imposing emergency transfer limits, and suggested language was presented in the current draft. The remaining language of Section 5.5 was reviewed in detail, with the following comments proposed:

**5.5 Transmission Operating Criteria**

R1. Each Reliability Coordinator shall notify adjacent Reliability Coordinators of the forced outage of any facility on the NPCC Transmission Facilities Notification List.

R2. Each Reliability Coordinator shall coordinate scheduled outages with adjacent Reliability Coordinators of any facility on the NPCC Transmission Facilities Notification List.

**The old R1. and R2. broadly replicate TOP-002-2.b, R3 and R4, and IRO-014-2, R1 and R3. The NPCC specific language above captures the NPCC Facilities Notification List maintained by the RCs.**

**The old R3 replicates R2 of PRC-001-1, TOP-002-2b, R5 and R6, and IRO-008-1, R1 and R2.**

R4. Each Transmission Operator shall meet the **Normal Transfer Capability** performance requirements listed below for BPS facilities.

R4.1. Pre-contingency voltages, line and equipment loadings shall be within normal limits.

R4.2. Unless specific instructions describing alternate action are in effect, manual reclosing of a faulted element can be carried out before any manual system adjustment, without affecting the **stability** of the **bulk power system**.

R4.3 **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 **either 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.

R5. Each Transmission Operator shall maintain line, voltage and equipment loadings within normal limits for pre-disturbance conditions and within applicable emergency limits for the system conditions that exist following the contingencies specified in R4.3 This is permissible provided 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 significant adverse impact.

R6. Each Transmission Operator shall plan to operate to Normal Transfer Capability. It is acceptable to operate to Emergency Transfer Capability post-contingency when it is unable to meet Normal Transfer Capability without interrupting firm load..

R7. Each Transmission Operator shall meet the Emergency Transfer Capability performance requirements listed below.

R7.1 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 or single line to ground fault on any generator, transmission circuit, transformer or bus section, with **normal fault clearing**.

**a.** A single pole DC line with **normal fault clearing.**
b. The loss of any **element** without a fault.

R7.2 Line, voltage and equipment loadings shall be maintained within applicable emergency limits for the system conditions that exist following the contingencies specified in R7.1.

Emergency actions, including the pre-contingent shedding of firm load if necessary, must be implemented to limit transfers to within the requirements specified in R7.1

**What is the intent of the above language, a statement of fact regarding the new configuration OR a statement of the need to re-prepare the system within 30 minutes?**

R8. Post-contingency, each Transmission Operator shall take the following actions:

R8.1. Assess the status of the bulk power system and adjust transfer levels, if necessary, to prepare for the next contingency, .

R8.2. Implement emergency actions up to and including voltage reduction and shedding of firm **load**. if the readjustment of generation, **load** resources, phase angle regulators, and direct current facilities is not adequate to restore the system to within applicable emergency limits.

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**.

R8.3. Complete system adjustments as soon as possible , but no longer than30 minutes..

R11. Each Transmission Operator shall consider operating in a more conservative manner than that required by R4 & R7 when high risk conditions exist.

The TFCO agreed to continue its review of NPCC Regional Reliability Reference Directory 1, “Design and Operation of the Bulk Power System,” at its August meeting, and, if it can be scheduled, through a conference call in advance of the meeting.

Final minutes issued on July 11, 2012
Revised final minutes issued on July 13, 2012

Prepared by:

John G. Mosier, Jr.

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
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# NPCC
# Regional Reliability Reference Directory # 8
# System Restoration

| Task Force on Coordination of Operations Revision Review Record: |
|---|
| **October 21, 2008** |
| **October 22, 2010** |
| |

Adopted by the Members of the Northeast Power Coordinating Council, Inc. this October 22, 2008, 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) |
|---|---|---|---|
| 1 | 10/22/2010 | Revised Sections 5.7.4.4 and 5.7.5.2 Battery Testing | Revision |
| | | | |
| | | | |
| | | | |
| | | | |


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Appendix A

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# 1.0 Introduction

## 1.1 Title System Restoration

## 1.2 Directory Number 8

## 1.3 Objective

The purpose of this Directory is to present the basic criteria with which each applicable entity must plan for and perform power system restoration following a major or a total blackout.

Compliance to the criteria set forth in this Directory document by each applicable entity assures the capabilities to perform power system restoration.

The functional requirements and performance of operational monitoring and control systems, **operator** voice communications and data telecommunications are beyond the scope of this Directory, except particular requirements for system restoration.

On an annual basis, the NPCC Inc. Task Force on Coordination of Operation shall review and accept each applicable entity's restoration plan for viability and coordination with other operating entities. The composite of the individual restoration plans, once reviewed and accepted by NPCC, comprises NPCC's regional restoration plan.

## 1.4 Effective Date **October 21, 2008**

## 1.5 Background

This Directory was developed from the draft NPCC A-12 System Restoration Criteria document (January 10, 2008 version) and associated C-35 Procedure document. Guidelines and procedures for consideration in the implementation of this Directory are provided in Appendix B.

## 1.6 Applicability

### 1.6.1 Functional Entities

Reliability Coordinators
Transmission Operators
Balancing Authorities
Transmission Owners

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Generator Owners

2.0 Terms Defined in this Directory

The definitions of terms found in this Directory appearing in bold typeface, including those terms used in Appendix B, 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-005-2
3.2 EOP-006-2

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Full Member, More Stringent Criteria

These Criteria are in addition to and more stringent or more specific than the NERC or any Regional Reliability standard requirements.

5.1 System Restoration Plan Requirements

Each Reliability Coordinator and Transmission Operator shall develop and maintain a system restoration plan for its operating area[1] that meets NERC requirements. In addition, the restoration plan shall:

5.1.1 identify the operating area's **basic minimum power system**(s);

5.1.2 address the priority of restoring off-site power to nuclear plants;

5.1.3 identify interconnection points with adjacent operating areas;

5.1.4 identify **synchronization** parameters;

5.1.5 address coordination of system restoration with neighboring operating areas;

5.1.6 provide for the reenergization of transmission systems to major

[1] Operating area means the Reliability Coordinating area or the Transmission Operator area as defined in the NERC Functional Model.

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generating stations , including inter-area tie points;

5.1.7 address electrical **island** stabilization;

5.1.8 identify provisions for fuel resources to support operation of any supplementary generators (e.g., a diesel generator) necessary for operating **key facilities** consistent with the expected requirements of the Restoration Plan.

5.2 **Basic Minimum Power System** Determination Requirements

5.2.1 The **basic minimum power system** shall consist 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.

5.2.2 A Reliability Coordinator and Transmission Operator may utilize more than one **basic minimum power system** to initiate the restoration process. In determining such a system(s), the Reliability Coordinator and the Transmission Operator shall involve all affected parties or entities.

5.2.3 The **basic minimum power system** shall include the capability to:

5.2.3.1 utilize **blackstart** generators;

5.2.3.2 form an electrical **island**;

5.2.3.3 **synchronize** electrical **islands;** and

5.2.3.4 permit the continuation of the system restoration plan.

5.3 Identification of **Key Facilities** and Associated **Critical Components**

5.3.1 The Reliability Coordinator shall identify the **key facilities**.

5.3.2 The Transmission Owners and Generator Owners of the **key facility** shall identify the associated **critical components.**

5.4 Power System Restoration Event Analysis

5.4.1 Reliability Coordinator Restoration Evaluation


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Following an event where the system restoration plan was invoked, the Reliability Coordinator shall report on the performance of its restoration plan..

5.4.2 Transmission Operator Restoration Evaluation

Following an event where the system restoration plan was invoked, the Transmission Operator shall report on the performance of its restoration plan.

5.5 Testing Requirements for Facilities Associated with Interconnection Points

Each Transmission Owner of facilities that connect the **basic minimum power system** to interconnection points as agreed to by adjacent areas shall have maintenance and testing program for the associated equipment required for continued and proper operation in the event of a total loss of grid supply. Upon request, a summary of the maintenance and testing records shall be provided to the Reliability Coordinator.

5.6 Testing Requirements for Facilities Associated with Offsite Power to Nuclear Generating Plants

Each Transmission Owner of facilities that connect the **basic minimum power system** to nuclear plants shall have a maintenance and testing program for the associated equipment required for continued and proper operation in the event of a total loss of grid supply. Upon request, a summary of the maintenance and testing records shall be provided to the Reliability Coordinator.

5.7 Testing Requirements for Critical Components Associated with Key Facilities

Each Transmission Owner and Generator Owner of a **key facility** shall:

- maintain a list of **critical components** associated with each **key facility**;
- perform the tests outlined in Table 1;
- maintain records of the test results; and
- provide the above upon request to the Reliability Coordinator and Transmission Operator.

Note that the occurrence of an actual successful event can be considered as a completed test, provided it can be demonstrated that the operation of the facility during the event met the test objectives and performance of these criteria.

The NPCC Compliance Committee stipulates the reporting requirements by the

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Transmission Owner and Generator Owner.

5.7.1 Reporting on Failure of Critical Components Associated with Key Facilities

The Transmission Operator shall report to its Reliability Coordinator, failure of a test or the failure of **critical components** associated with **key facilities**:

5.7.1.1 As soon as possible and no later than 15 minutes after its control room has confirmed the loss of functionality at **a key facility** due to the failure of **critical components**. Loss of functionality at a **key facility** is defined as the loss of operability which can negatively impact the restoration plan. Examples of such conditions are:

- Loss of equipment control;
- Complete loss of AC or DC service supply;
- Loss of Blackstart facilities

5.7.1.2 As soon as possible and no later than 24 hours after their control room staff becomes aware of the failure of **critical components** associated with **key facilities** which results in a loss of redundancy at a **key facility**. Examples of such conditions are:

- Loss of a redundant AC or DC service supply;
- Loss of redundant Blackstart facilities

The report shall identify remedial actions to be undertaken, including the estimated date by which the work is to be completed.

5.7.2 Blackstart Generating Unit Startup Test (Reference: Table 1; Test BS-1)

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.

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5.7.2.2 Each Reliability Coordinator and Transmission Operator shall ensure that the Generator Owner of a blackstart **generation** facility included in its restoration plan complete a successful blackstart test consistent with the objectives of its system restoration plan.

5.7.2.3 Operations voice communications and system control and data acquisition (SCADA) that are required for **blackstart** shall be verified to operate adequately without dependency on the interconnected system or other unrelated unit support for any source of station service.

5.7.3 Cable Backup Pressurization System Test (Reference: Table 1; Test UG-1)

Certain underground transmission cables require the capability to pressurize the insulating medium to maintain dielectric strength. The capability to do so during a blackout is essential to maintain the availability of such underground cables for service and to preclude any damage to the cables upon energizing. The Transmission Owner shall test the underground transmission cable's capability either by testing the cable's backup pressurization system or by powering the cable's normal pressurizing system from a backup power source (e.g. backup generator). This test shall be conducted every six (6) months by demonstrating that the required pressures can be maintained for a minimum of thirty (30) minutes.

5.7.4 Substation and Telecommunication Backup Power Supplies - Batteries and Generators Test (Reference: Table 1; Tests ST-1 to ST-6)

Transmission Owners shall test the backup power supplies in substations and telecommunication sites that are identified as **critical components** as specified below. Separate backup power arrangements for these substations and sites shall be separately identified in the **critical components** listing, and shall be inspected and tested individually.

The required tests are as follows:

5.7.4.1 Equipment Integrity Check
Battery charger and batteries shall be inspected annually and meet the Transmission Owner's / Transmission Operator's battery integrity standards. (Reference: Table 1; Test ST-1)

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5.7.4.2 AC Supply Interruption Test
Interruption of AC supply to a battery charger shall be carried out annually to ensure a battery picks up and carries load. (Reference: Table 1; Test ST-2)

5.7.4.3 Reconfirm Critical Component Load Connections
The Transmission Owner's design and commissioning requirements must ensure that all critical component loads are supplied from batteries and battery charger as part of the engineering and design. If, and when, modifications are made, and/or every five years, the Transmission Owner shall reconfirm through its design review and/or through testing that all critical component loads are connected to the battery and the battery charger. (Reference: Table 1; Test ST-3)

5.7.4.4 Performance Test of Battery Capacity
Performance testing of batteries in substations and telecommunication sites (control centers) shall be done at least once every five (5) years, for the time required per the test procedure, to verify battery design capabilities. A performance test of battery capacity using a procedure endorsed by a recognized standard setting organization is acceptable. The success of a performance test is when average and individual cell performance parameters are within prescribed design limits. (Reference: Table 1; Test ST-4)

5.7.4.5 Startup And Run Test
For substations and telecommunication sites provided with backup power generators, a startup and run test shall be performed monthly for a minimum run time of fifteen (15) minutes. (Reference: Table 1; Test ST-5)

5.7.4.6 Startup, Transfer and Load Test
For substations and telecommunication sites provided with automatically started backup power generators, the asset owner shall verify that the generators will pick up the critical load following the loss of station service. A startup, transfer and run test simulating the loss of station service will be performed annually for a duration of at least thirty (30) minutes. (Reference: Table 1; Test ST-6)

For manually started back-up emergency generators, the asset owner shall start the generator and verify stable operation for 30 minutes while supplying critical loads. (Reference: Table 1; Test ST-6)

5.7.5 Control Center and Telecommunication Center Facilities Test
(Reference: Table 1; Tests CC-1 To CC-5)

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5.7.5.1 AC Supply Interruption Test

Each Reliability Coordinator, Transmission Operator and Balancing Authority shall test its facilities in the control centers and the telecommunication centers to demonstrate the computer systems will be functional when required for system restoration, without dependencies on power sources unavailable during a partial or complete system blackout. The uninterruptible power supply (UPS) systems in control centers and telecommunication centers shall be tested annually by interrupting AC supply and verifying that all critical component loads are supplied for a time that is sufficient for backup power sources to restore the AC input to the UPS. (Reference: Table 1; Test CC-1)

5.7.5.2 Performance Test of Battery Capacity

Performance testing of batteries in control centers and telecommunication centers shall be done at least once every five (5) years, for the time required per the test procedure, to verify battery design capabilities. A performance test of battery capacity using a procedure endorsed by a recognized standard setting organization is acceptable. The success of a performance test is when average and individual cell performance parameters are within prescribed design limits. (Reference: Table 1; Test CC-2)

5.7.5.3 Startup and Run Test
For control centers and telecommunication centers provided with a backup power generator, a startup and run test shall be performed monthly for at least fifteen (15) minutes. (Reference: Table 1; Test CC-3)

5.7.5.4 Startup, Transfer and Load Test
For control centers and telecommunication centers provided with a backup power generator, verification that the generators will pick up the required load (including heating, ventilation and air conditioning (HVAC) for computer systems) during the loss of station service shall be provided. A startup, transfer and run test simulating the loss of station service shall be performed annually for a duration of at least thirty (30) minutes. During the test, the operation of the auxiliaries shall be verified. (Reference: Table 1; Test CC-4)

5.7.5.5 Computer Redundancy Test
Each Reliability Coordinator, Transmission Operator and Balancing Authority shall test its computer redundancy features every six (6)

months to ensure computer systems continue to function adequately. (Reference: Table 1; Test CC-5)

6.0 Measures and Assessments

M1. Each Reliability Coordinator and Transmission Operator shall have a dated, documented system restoration plan developed in accordance with Section 5.1, "System Restoration Plans."

M2. Each Reliability Coordinator shall have documentation identifying the Basic Minimum Power System for its area, in accordance with Section 5.2, that incorporates the components and the Key Facilities identified in Section 5.3. Each Reliability Coordinator shall have a list of the Key Facilities for its Reliability Coordinator Area in accordance with Section 5.3.1.

M3 Each asset owner shall have documentation identifying the Critical Components of Key Facilities in its area or facility, in accordance with Section 5.3.2.

M4 If there has been an event in which the Restoration Plan, or parts thereof, have been utilized, each Reliability Coordinator and Transmission Operator shall report on the performance of the Restoration Plan in accordance with Section 5.4.

M5. Each Transmission Owner shall provide self-certification of a maintenance and testing program for the associated equipment required for continued and proper operation of facilities between interconnection points and the Basic Minimum Power System, in accordance with Section 5.5.

M6. Each Transmission Owner shall provide self-certification of a maintenance and testing program for the associated equipment required for continued and proper operation of facilities between nuclear plants and the Basic Minimum Power System, in accordance with Section 5.6.

M7. Each Transmission Operator shall ensure Transmission Owners and Generator Owners of a key facility test these facilities in accordance with Section 5.7.

M8. Each asset owner shall self-certify maintenance and testing of critical components in accordance with Section 5.7.

---

Prepared by: Task Force on Coordination of Operation and Task Force on System Studies

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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: None

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Table 1 - Standard Test Procedures for key facilities
and associated critical components required for system restoration

| **Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration** | | | | |
|---|---|---|---|---|
| **Test No.** | **Critical Component** | **Test** | **Test Frequency and Duration** | **Criteria for Successful Test** |
| **BS-1** | Blackstart Generating Units | Blackstart Generating Unit Startup Test | Frequency: annual<br><br>Duration: 10 minutes of stable operation | Successful startup and 10 minutes of stable operation<br><br>All operating aids and auxiliary systems are independent. |
| | | | | |
| **UG-1** | Pressurization system of underground transmission cables | Cable Backup Pressurization System Test | Frequency: every 6 months<br><br>Duration: minimum of 30 minutes | Maintains safe dielectric pressure for the minimum test period |

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| Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration | | | | |
|---|---|---|---|---|
| **Test No.** | **Critical Component** | **Test** | **Test Frequency and Duration** | **Criteria for Successful Test** |
| **ST-1** | Battery charger and batteries in substation and Telecommunication site | Equipment Integrity Check | Frequency: annually | Meet Transmission Owner / Operator battery integrity standards |
| **ST-2** | Battery charger and batteries in substation and Telecommunication site | AC Supply Interruption Test | Frequency: annually | Maintain acceptable voltage levels for the duration of the test |
| **ST-3** | Battery charger and batteries in substation and Telecommunication site | Reconfirm Critical Component Load Connections | Frequency: once every 5 years or when modifications are made | Confirm that all critical **loads** are supplied from battery charger and batteries. |

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| Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration | | | | |
|---|---|---|---|---|
| **Test No.** | **Critical Component** | **Test** | **Test Frequency and Duration** | **Criteria for Successful Test** |
| **ST-4** | Batteries in substation and telecommunication site | Performance Test of Battery Capacity | Frequency: at least once every five years<br><br>Duration: for the time required per the test procedure to verify battery design capabilities | The success of a performance test is when average and individual cell performance parameters are within prescribed design limits. |
| **ST-5** | Backup generator in substation and Telecommunication site | Startup and Run Test | Frequency: monthly<br><br>Duration: minimum of 15 minutes | Successful startup followed by 15 minutes of stable operation |
| **ST-6** | Backup generator in substation and Telecommunication site | Startup, Transfer and Load Test | Frequency: annually<br><br>Duration: minimum of 30 minutes | - Successful startup (automatically started type)<br>- Transfer scheme operates correctly (automatically started type)<br>- 30 minutes of stable operation supplying critical **loads** (both automatically and manually started backup generators) |


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| Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration | | | | |
|---|---|---|---|---|
| **Test No.** | **Critical Component** | **Test** | **Test Frequency and Duration** | **Criteria for Successful Test** |
| CC-1 | Uninterruptible power supply (UPS) system in control center and Telecommunication center | AC Supply Interruption Tests | Frequency: annually<br><br>Duration: for a time that is sufficient for backup power sources to restore AC supply to the UPS | No impact on computer or telecommunication functions during testing |
| CC-2 | Batteries in control center and telecommunication center | Performance Test of Battery Capacity | Frequency: at least once every five years<br><br>Duration: for the time required per the test procedure to verify battery design capabilities | The success of a performance test is when average and individual cell performance parameters are within prescribed design limits. |
| CC-3 | Backup generator in control center and Telecommunication center | Startup and Run Test | Frequency: monthly<br><br>Duration: minimum of 15 minutes | Successful startup followed by 15 minutes of stable operation |

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| Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration | | | | |
|---|---|---|---|---|
| **Test No.** | **Critical Component** | **Test** | **Test Frequency and Duration** | **Criteria for Successful Test** |
| CC-4 | Backup generator in control center and Telecommunication center | Startup, Transfer and Load Test | Frequency: annually<br><br>Duration: minimum of 30 minutes | - Successful startup<br>- Transfer scheme operates correctly<br>- 30 minutes of stable operation supplying **loads** critical to system restoration<br>- When HVAC system restarts, ambient temperature is in the range of equipment working temperature |
| **CC-5** | Computer systems | Computer Redundancy Test | Redundancy check every 6 months | - No impact on computer functions during testing.<br>- Successful switching / testing without equipment failure. |

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# Appendix A
# Definition of Terms[2]

**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 on page 6 of this glossary).

**Area Control Error** — the instantaneous difference between actual and net **scheduled interchange**, taking into account the effects of frequency bias.

**Automatic Generation Control (AGC)** — Equipment that automatically adjusts a **Control Area**'s **generation** to maintain its **interchange schedule** plus its share of frequency regulation.

**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.

**Bipolar** — Operation of **HVdc** with two **poles** of opposite polarity with negligible ground current.

**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.

**Critical Component** — 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;
- control center and telecommunication center computer room HVAC;
- telecommunication facilities backup power supplies; and
- cable pressurization systems at or between key facilities.

[2] These terms will be moved and grouped under a separate Directory when all other Directories are developed.

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**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.

**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.

**Energize** — To make a piece of equipment or circuit alive.

**First Contingency Loss** — The largest **capacity** outage including any assigned Ten-Minute Reserve which would result from the loss of a single **element**

**HVdc Link** — A high Voltage direct current connection between two **power** systems, often used to interconnect two asynchronous **power** systems.

**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 non-utility generator to a **Control Area** or system.

**Interface** — The specific set of transmission **elements** between two areas or between two areas comprising one or more electrical systems.

**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**.

**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.


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**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.

**Operator, System** - Person responsible for operating control of the **bulk power system** in an **Area** of NPCC or an adjoining system interconnected with NPCC. This could be a Security Coordinator, a **Control Area** Operator or in some cases a bulk power utility operator (e.g. NYPA, Niagara Mohawk, etc)

**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).

**Rating** — The operational limits of an electric system, facility, or **element** under a set of specified conditions.

**Reclosing**

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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.

**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**

**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).

**Synchronism-check Relay** — A verification **relay** whose function is to operate when two input voltages satisfy predetermined operating parameters.

**Tie Line** — A circuit connecting two or more **Control Areas** or systems of an electric system


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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: May 25, 2012<br>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<br><br>"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."**

# Arizona-Southern California Outages on September 8, 2011

## Causes and Recommendations



Prepared by the Staffs of the

Federal Energy Regulatory Commission

*and the*

North American Electric Reliability Corporation

April 2012

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APPENDICES 114

# I. EXECUTIVE SUMMARY

## A. Synopsis of the Disturbance and System Recovery

On the afternoon of September 8, 2011, an 11-minute system disturbance occurred in the Pacific Southwest, leading to cascading outages and leaving approximately 2.7 million customers without power.[1] The outages affected parts of Arizona, Southern California, and Baja California, Mexico. All of the San Diego area lost power, with nearly one-and-a-half million customers losing power, some for up to 12 hours. The disturbance occurred near rush hour, on a business day, snarling traffic for hours. Schools and businesses closed, some flights and public transportation were disrupted, water and sewage pumping stations lost power, and beaches were closed due to sewage spills. Millions went without air conditioning on a hot day.

The loss of a single 500 kilovolt (kV)[2] transmission line initiated the event, but was not the sole cause of the widespread outages. The system is designed, and should be operated, to withstand the loss of a single line, even one as large as 500 kV. The affected line—Arizona Public Service's (APS) Hassayampa-N. Gila 500 kV line (H-NG)—is a segment of the Southwest Power Link (SWPL), a major transmission corridor that transports power in an east-west direction, from generators in Arizona, through the service territory of Imperial Irrigation District (IID), into the San Diego area. It had tripped on multiple occasions, as recently as July 7, 2011, without causing cascading outages.

With the SWPL's major east-west corridor broken by the loss of H-NG, power flows instantaneously redistributed throughout the system, increasing flows through lower voltage systems to the north of the SWPL, as power continued to flow into San Diego on a hot day during hours of peak demand. Combined with lower than peak

[1] "Customers" are not the same as "people" in utility parlance. The term customer generally refers to a single meter, whether at a residence, an apartment building, or a factory. Thus, a single customer could represent one or more persons, and a single person could be two customers, for example, if the same utility served both an individual's residence and his small business. Estimates of "people" affected by blackouts generally are prepared by increasing the customer numbers by a multiplier, often two or three.

[2] A list of acronyms used in this report is included in Appendix A.

generation levels in San Diego and Mexico,[3] this instantaneous redistribution of power flows created sizeable voltage deviations and equipment overloads to the north of the SWPL. Significant overloading occurred on three of IID's 230/92 kV transformers located at the Coachella Valley (CV) and Ramon substations, as well as on Western Electricity Coordinating Council (WECC) Path 44,[4] located south of the San Onofre Nuclear Generating Station (SONGS) in Southern California.

The flow redistributions, voltage deviations, and resulting overloads had a ripple effect, as transformers, transmission lines, and generating units tripped offline, initiating automatic load shedding throughout the region in a relatively short time span. Just seconds before the blackout, Path 44 carried all flows into the San Diego area as well as parts of Arizona and Mexico. Eventually, the excessive loading on Path 44 initiated an intertie separation scheme at SONGS, designed to separate SDG&E from SCE. The SONGS separation scheme separated SDG&E from Path 44, led to the loss of the SONGS nuclear units, and eventually resulted in the complete blackout of San Diego and Comisión Federal de Electricidad's (CFE) Baja California Control Area. During the 11 minutes of the event, the WECC Reliability Coordinator (WECC RC) issued no directives and only limited mitigating actions were taken by the Transmission Operators (TOPs) of the affected areas.

As a result of the cascading outages stemming from this event, customers in the SDG&E, IID, APS, Western Area Power Administration-Lower Colorado (WALC), and CFE territories lost power, some for multiple hours extending into the next day. Specifically,

- SDG&E lost 4,293 Megawatts (MW) of firm load, affecting approximately 1.4 million customers.
- CFE lost 2,150 MW of net firm load, affecting approximately 1.1 million customers.[5]
- IID lost 929 MW of firm load, affecting approximately 146,000 customers.

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[3] Total summer peak generation for San Diego Gas and Electric's (SDG&E) territory and Comisión Federal de Electricidad's (CFE) Baja California Control Area is 5,774 MW. On September 8, 2011, the total generation for SDG&E and CFE's Baja California Control Area was 4,168, a difference of 1,606 MW.

[4] Path 44 is one of 81 Rated Paths in the WECC region. A Rated Path is composed of "an individual transmission line or a combination of parallel transmission lines." WECC 2011 Path Rating Catalog, January 2011, at item 1-i. Path 44, also referred to as "South of SONGS," is an aggregation of five 230 kV lines that delivers power in a north-south direction from the Southern California Edison (SCE) footprint in the Los Angeles area into the SDG&E footprint.

5 CFE is Mexico's state-owned utility. Only its Baja California Control Area was affected on September 8, 2011. The inquiry is particularly grateful to CFE for its willingness to share data and information to assist the inquiry in developing the most accurate conclusions and recommendations.

- APS lost 389 MW of firm load, affecting approximately 70,000 customers.
- WALC lost 74 MW of firm load, 64 MW of which affected APS's customers. The remaining 10 MW affected 5 WALC customers.

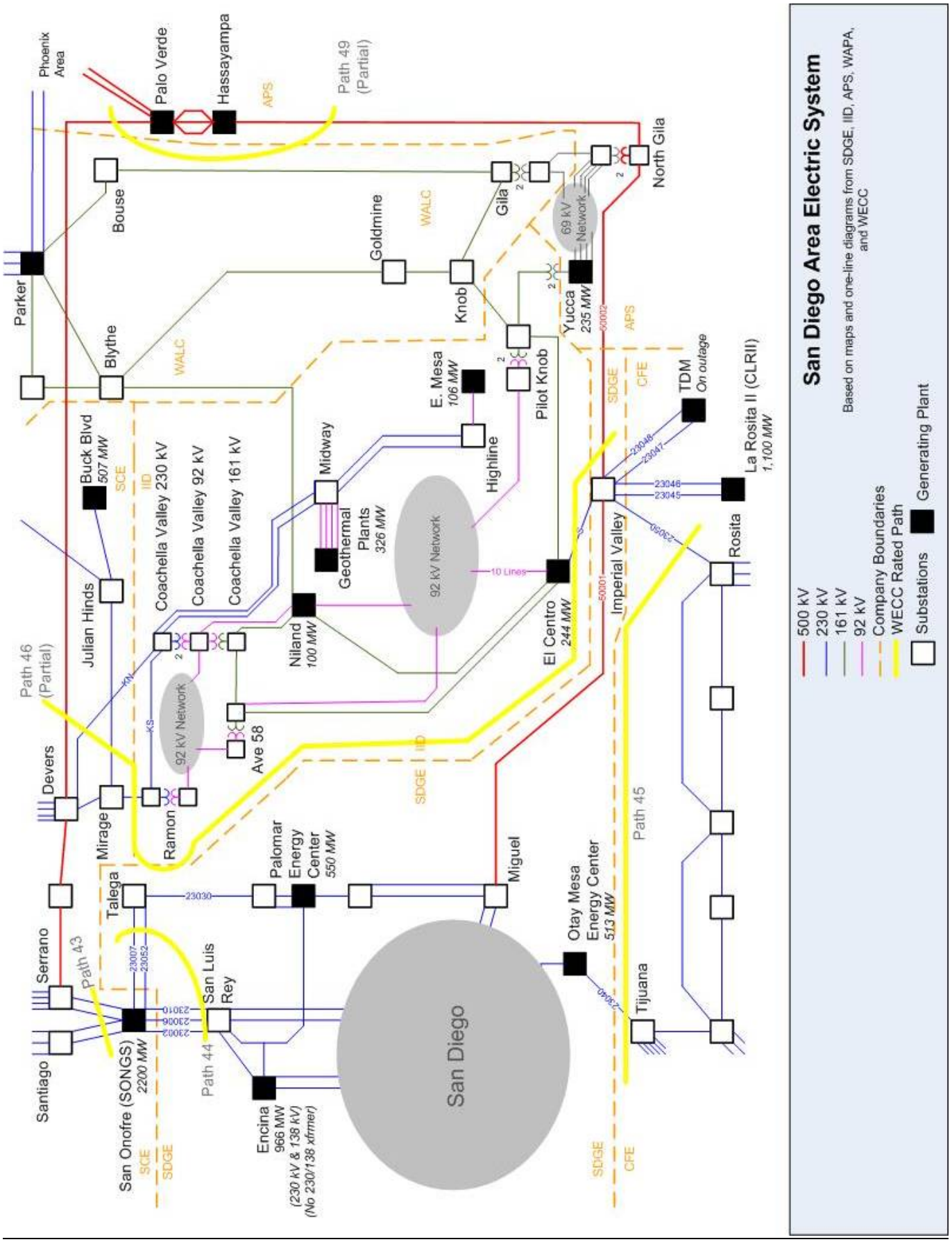
After the blackout, the affected entities promptly instituted their respective restoration processes.[6] All of the affected entities had access to power from their own or neighboring systems and, therefore, did not need to use "black start" plans.[7] Although there were some delays in the restoration process due to communication and coordination issues between entities, the process was generally effective. SDG&E took 12 hours to restore 100% of its load, and CFE took 10 hours to restore 100% of its load. IID, APS, and WALC restored power to 100% of their customers in approximately 6 hours. The affected entities also worked to restore generators and transmission lines that tripped during the event. IID and APS restored generation—333 MW for IID and 76 MW for APS—in 5 hours. Meanwhile, CFE restored 1,915 MW of tripped generation in 56 hours; SDG&E restored 2,229 MW of tripped generation in 39 hours; and SCE restored 2,428 MW of tripped generation in 87 hours. IID restored its 230 kV transmission system in 12 hours and its 161 kV system in 9 hours; APS restored H-NG in 2 hours; SDG&E restored its 230 kV system in 12 hours; WALC restored its 161 kV system in 1.5 hours; and CFE restored its 230 kV system in 13 hours and its 115 kV system in 10 hours.

## B. Map of Affected Area and Key Facilities Involved in the Event

The following map, showing the areas affected by the September 8th event and the key facilities involved during the event, can be used as a reference throughout the report:

[6] The term "affected entities" in this report refers to TOPs and Balancing Authorities (BAs) that were affected by the event. The affected entities include SDG&E, IID, APS, WALC, SCE, CFE, and the California Independent System Operator (CAISO).

[7] Black start plans work to energize systems using internal generation to get from shutdown to operating condition without assistance from the Bulk Electric System (BES).


San Diego Area Electric System
Based on maps and one-line diagrams from SDGE, IID, APS, WAPA, and WECC
500 kV
230 kV
161 kV
92 kV
Company Boundaries
WECC Rated Path
Substations
Generating Plant
Phoenix Area
Palo Verde
Hassayampa
Path 49 (Partial)
APS
North Gila
Bouse
Gila
Goldmine
WALC
69 kV Network
Parker
Knob
Yucca 235 MW
Blythe
Pilot Knob
E. Mesa 106 MW
TDM On outage
La Rosita II (CLRII) 1,100 MW
Buck Blvd 507 MW
SCE
IID
Coachella Valley 230 kV
Coachella Valley 92 kV
Coachella Valley 161 kV
Midway
Highline
Geothermal Plants 326 MW
92 kV Network
10 Lines
Imperial Valley
El Centro 244 MW
Rosita
Julian Hinds
Niland 100 MW
Path 46 (Partial)
Devers
Ave 58
Ramon
Mirage
Palomar Energy Center 550 MW
Miguel
Path 45
Talega
Otay Mesa Energy Center 513 MW
Serrano
Path 43
San Luis Rey
Tijuana
Santiago
San Onofre (SONGS) 2200 MW
Path 44
Encina 966 MW (230 kV & 138 kV) (No 230/138 xfrmer)
San Diego
SDGE
CFE

## C. Key Findings, Causes, and Recommendations[8]

The September 8, 2011, event showed that the system was not being operated in a secure N-1 state.[9] This failure stemmed primarily from weaknesses in two broad areas—operations planning and real-time situational awareness—which, if done properly, would have allowed system operators to proactively operate the system in a secure N-1 state during normal system conditions and to restore the system to a secure N-1 state as soon as possible, but no longer than 30 minutes. Without adequate planning and situational awareness, entities responsible for operating and overseeing the transmission system could not ensure reliable operations within System Operating Limits (SOLs) or prevent cascading outages in the event of a single contingency.[10] As demonstrated in Appendix C, inadequate situational awareness and planning were also identified as causes of the 2003 blackout that affected an estimated 50 million people in the United States and Canada.

The inquiry also identified other underlying factors that contributed to the event, including: (1) not identifying and studying the impact on Bulk-Power System (BPS)[11]

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[8] While this section highlights the most significant causes, findings, and recommendations, the report details the complete list of findings, causes, and recommendations in section IV. In addition, for ease of reference all of the findings and recommendations are summarized in table format in Appendix B.

[9] The North American Electric Reliability Corporation's (NERC) mandatory Reliability Standards applicable to the BES require that the BES be operated so that it generally remains in a reliable condition, without instability, uncontrolled separation or cascading, even with the occurrence of any single contingency, such as the loss of a generator, transformer, or transmission line. This is commonly known as the "N-1 criterion." N-1 contingency planning allows entities to identify potential N-1 contingencies before they occur and to adopt mitigating measures, as necessary, to prevent instability, uncontrolled separation, or cascading. As the Federal Energy Regulatory Commission (Commission) stated in Order No. 693 with regard to contingency planning, "a single contingency consists of a failure of a single element that faithfully duplicates what will happen in the actual system. Such an approach is necessary to ensure that planning will produce results that will enhance the reliability of that system. Thus, if the system is designed such that failure of a single element removes from service multiple elements in order to isolate the faulted element, then that is what should be simulated to assess system performance." *Mandatory Reliability Standards for the Bulk Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1716 (2007), *order on reh'g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007).

[10] A contingency is the unexpected failure of an electrical system component.

[11] The BPS is defined by Section 215(a) (1) of the Federal Power Act as "facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability." The meaning of BPS and BES differ somewhat and, thus, this report uses each term in its proper context. With respect to reliability, the Commission has jurisdiction over all users, owners, and operators of the BPS. In Order No. 693 at P 75, the Commission adopted, at least for an initial period, the BES definition as the threshold for application of the NERC Reliability Standards. Thus, this report uses BES when referring to entities' specific facilities or elements that are subject to the Reliability Standards, but BPS when discussing the overall reliability impact. On January 25, 2012,

reliability of sub-100 kV facilities in planning and operations;[12] (2) the failure to recognize Interconnection Reliability Operating Limits (IROLs) in the Western Interconnection;[13] (3) not studying and coordinating the effect of protection systems, including Remedial Action Schemes (RASs), during plausible contingency scenarios;[14] and (4) not providing effective tools and operating instructions for use when reclosing lines with large phase angle differences across the reclosing breakers.[15]

With regard to operations planning, some of the affected entities' seasonal, next-day, and real-time studies do not adequately consider: (1) operations of facilities in external networks, including the status of transmission facilities, expected generation output, and load forecasts; (2) external contingencies that could impact their systems or internal contingencies that could impact their neighbors' systems; and (3) the impact on BPS reliability of internal and external sub-100 kV facilities. As a result, these entities' operations studies did not accurately predict the impact of the loss of APS's H-NG or the loss of IID's three 230/92 kV transformers. If the affected entities had more accurately predicted the impact of these losses prior to the event, these entities could have taken appropriate pre-contingency measures, such as dispatching additional generation to mitigate overloads and prevent cascading outages.

To improve operations planning in the WECC region, this report makes several recommendations designed to ensure that TOPs and BAs,[16] as appropriate: (1) obtain information on the operations of neighboring BAs and TOPs, including transmission outages, generation outages and schedules, load forecasts, and scheduled interchanges;

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NERC filed a petition with the Commission for approval of a revised definition of the BES. The proposed definition of BES would cover all elements operated at 100 kV or higher, with a list of specific inclusions and exclusions. Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher are on the list of specific inclusions. *See North American Electric Reliability Corp.,* Docket No. RM12-6-000. This report takes no position on the petition.

[12] This report does not attempt to define the limits of which sub-100 kV facilities impact BPS reliability. Certainly, many facilities below 100 kV do not impact BPS reliability. The sub-100 kV facilities in this event affected the BPS because they were in parallel to significant transmission corridors.

[13] This report recommends that WECC RC should work with TOPs to consider whether any SOLs in the Western Interconnection constitute IROLs. As part of this effort, WECC RC should: (1) work with affected TOPs to consider whether Path 44 and H-NG should be recognized as IROLs; and (2) validate existing SOLs and ensure that they take into account all transmission and generation facilities and protection systems that impact BPS reliability.

[14] This failure caused the derived SOLs on H-NG and Path 44 to be invalid on the day of the event.

[15] As discussed in more detail in connection with Finding and Recommendation 27 below, when a line trips, the phase angle at one end of the line may be much larger than the phase angle at the other end. If the difference between the two angles is too great, reclosing the line could cause damage to generators or even system instability.

[16] See "Reliability Responsibilities" section at page 16 below.

(2) identify and plan for external contingencies that could impact their systems and internal contingencies that could impact their neighbors' systems; and (3) consider facilities operated at less than 100 kV that could impact BPS reliability. This effort should include a coordinated review of planning studies to ensure that operation of the affected Rated Paths will not result in the loss of non-consequential load, system instability, or cascading outages, with voltage and thermal limits within applicable ratings for N-1 contingencies originating from within or outside an entity's footprint.

The September 8th event also exposed entities' lack of adequate real-time situational awareness of conditions and contingencies throughout the Western Interconnection. For example, many entities' real-time tools, such as State Estimator and Real-Time Contingency Analysis (RTCA), are restricted by models that do not accurately or fully reflect facilities and operations of external systems to ensure operation of the BPS in a secure N-1 state. Also, some entities' real-time tools are not adequate or operational to alert operators to significant conditions or potential contingencies on their systems or neighboring systems. The lack of adequate situational awareness limits entities' ability to identify and plan for the next most critical contingency to prevent instability, uncontrolled separation, or cascading outages. If some of the affected entities had been aware of real-time external conditions and run (or reviewed) studies on the conditions prior to the onset of the event, they would have been better prepared for the impacts when the event started and may have avoided the cascading that occurred.

To improve situational awareness in the WECC region, this report makes several recommendations: (1) expand entities' external visibility in their models through, for example, more complete data sharing; (2) improve the use of real-time tools to ensure the constant monitoring of potential internal or external contingencies that could affect reliable operations; and (3) improve communications among entities to help maintain situational awareness. In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS. These improvements will enable system operators to utilize real-time operating tools to proactively operate the system in a secure N-1 state.

In addition to the planning and situational awareness issues, several other factors contributed to the September 8th event. For example, WECC RC and affected entities do not consistently recognize the adverse impact that sub-100 kV facilities can have on BPS reliability. The prevailing SOLs should have included the effects of facilities that had not been identified and classified as part of the BES, as well as the effects of critical facilities such as Special Protection Systems (SPSs) and the SONGS separation scheme. Relevant

to the event, these entities did not consider IID's 92 kV network and facilities, including the CV and Ramon 230/92 kV transformers, as part of the BES, despite some previous studies indicating their impact on the BPS due to the fact they were electrically in parallel with higher-voltage facilities.[17] If these facilities had been designated as part of the BES, or otherwise incorporated into planning and operations studies and actively monitored and alarmed in RTCA systems, the cascading outages may have been avoided. Accordingly, the inquiry makes a recommendation to ensure that facilities that can impact BPS reliability, regardless of voltage level, are considered for classification as part of the BES and/or studied as part of entities' planning in various time horizons.

The inquiry also found some significant issues with protection system settings and coordination. For example, IID used conservative overload relay trip settings on its CV transformers. The relays were set to trip at 127% of the transformers' normal rating, which is just above the transformers' emergency rating (110% of normal rating). Such a narrow margin between the emergency rating and overload trip setting resulted in the facilities being automatically removed from service without providing operators enough time to mitigate the overloads. As a result of these settings, both CV transformers tripped within 40 seconds of H-NG tripping, initiating cascading outages. To avoid a similar problem in the future, the inquiry recommends that IID and other Transmission Owners (TOs) review their transformers' overload protection relay settings. A good guideline for protective relay settings is Reliability Standard PRC-023-1 R1.11, which states that relays be "set to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater." TOPs should also plan to take proper pre-contingency mitigation measures with due consideration for the applicable emergency ratings and overload protection settings (MW and time delay) before a facility loads to its relay trip point and is automatically removed from service.

The SONGS separation scheme's operation provides another example of the lack of studies on, and coordination of, protection systems. This scheme, classified by SCE as a "Safety Net,"[18] had a significant impact on BPS reliability, separating SDG&E from

[17] *See, e.g.*, CFE's Path 45 Increase Rating Phase 2 Study Report, January 12, 2011, at 19.

[18] A Safety Net protection system protects the power system from unexpected, low-probability events that are outside the normal planning criteria, but which may lead to a complete system collapse. Safety Nets operate to minimize the severity of the event and attempt to prevent a system collapse or cascading outages. A Safety Net is typically intended to handle severe disturbances resulting from extreme, though perhaps not well-defined, events. A Safety Net is subject to review by the WECC Remedial Action Scheme Reliability Subcommittee if unintended operation would result in cascading or other performance standard violations. WECC Guideline: Remedial Action Scheme Classification, February 9, 2009.

SCE, resulting in the loss of both SONGS nuclear generators, and blacking out SDG&E and CFE. Nevertheless, none of the affected entities, including SCE, as the owner and operator of the scheme, studied its impact on BPS reliability. The September 8th event shows that all protection systems and separation schemes, including Safety Nets, RASs, and SPSs, should be studied and coordinated periodically to understand their impact on BPS reliability to ensure their operation, inadvertent operation, or misoperation does not have unintended or undesirable effects.

# II. INTRODUCTION

## A. Inquiry Process

On September 9, 2011, the Commission and NERC jointly announced an inquiry to determine the causes of the outages and make recommendations for preventing such events in the future. The purpose of the inquiry was not to determine whether there may have been violations of applicable regulations, requirements, or standards subject to the Commission's jurisdiction. Thus, while this report describes conduct which may warrant future investigations under Part 1b of the Commission's regulations,[19] or actions by NERC under its Compliance Monitoring and Enforcement Program,[20] it draws no conclusions about whether violations occurred.

The inquiry was composed of smaller teams with particular subject-matter expertise, primarily from Commission and NERC professional staff, each of which conducted rigorous analyses of a key issue or issues involved in the event. Those teams and their primary responsibilities were as follows:

- **Sequence of Events** – developed a precise and accurate sequence of events (SOE) to provide a foundation for root cause analysis, computer model simulations, and other analytical aspects of the inquiry.
- **System Modeling and Simulation** – developed an accurate system modeling case, benchmarked the case to actual conditions at critical times, replicated system conditions leading up to and during the outage, and simulated alternate "what if" scenarios.
- **Root Cause and Human Performance Analysis** – performed in a systematic evaluation of the root causes and contributing factors and identified areas requiring further inquiry.
- **Operations Tools, Supervisory Control and Data Acquisition (SCADA)/Energy Management System (EMS), Communications, and Operations Planning** – considered all aspects of the blackout related to operator and reliability coordinator knowledge of system conditions, actions or inactions, and communications, particularly the observability of the electric system and effectiveness of operational reliability assessment tools.
- **Frequency/Area Control Error (ACE) Analysis** – reviewed potential frequency anomalies related to the blackout, and analyzed underfrequency generator, load, and tie line tripping.

[19] 18 C.F.R. Part 1b (2011).

[20] NERC Compliance Monitoring and Enforcement Program, Appendix 4C to the NERC Rules of Procedure, January 31, 2012.

- **System Planning, Design, and Studies** – analyzed factors used in setting SOLs and actual limits in effect on the day of the blackout, determined whether those limits were exceeded, and analyzed the extent to which actual system conditions varied from the assumptions used in setting the SOLs.
- **Transmission and Generation Performance, Protection, Control, Maintenance, and Damage** – analyzed the causes of automatic facility operations and generator trips, analyzed transmission and generation facility maintenance practices, and identified equipment damage.
- **Restoration Review** – reviewed the appropriateness and effectiveness of the restoration plans implemented, as well as the effectiveness of the coordination of these plans among the affected entities and WECC RC.

Each team not only examined its own subject area to determine what may have contributed to the event, but also considered lessons learned and potential recommendations for preventing such events in the future.

The inquiry devoted substantial time and resources to determine and study the causes of the event and develop meaningful recommendations with the goal of preventing similar events in the future. The team's analyses were extensive, involving the review of high-quality data from various reliability entities in the WECC region and simulations of the event using sophisticated computer models. Described below in summary form are the primary steps the inquiry took to complete its analysis.

## Data Gathering

The inquiry received and reviewed more than 20 gigabytes of data from approximately 500 data requests sent to entities in and around the affected areas. On September 19, 2011, the inquiry also began site visits with various entities involved in the outages, including entities with responsibility for balancing load and generation, transmission operation, and reliability coordination. During the site visits, the inquiry toured control centers, conducted dozens of interviews and depositions, and viewed equipment involved in the event. These visits and depositions allowed the inquiry to learn about control room operations and practices, system status and conditions on the day of the event, operating procedures, planning, operations, and real-time tools, and restoration planning and procedures. The inquiry also conducted dozens of follow-up meetings and issued follow-up data requests.

Of particular use to the inquiry were phasor measurement unit (PMU) records. PMUs are complex, multi-functional, high resolution recording devices installed widely throughout the Western Interconnection pursuant to a voluntary WECC-wide initiative. PMUs provide continuous, high-speed (30 scans per second) records of system conditions, including frequency, voltage, and phase angle relations. The continuous

nature of the data available through the PMUs, as well as their wide distribution throughout the power system, proved especially valuable to the inquiry in forming an accurate picture of the SOE and state of the system at particular points in time throughout the disturbance.

## SOE Methodology

More than 100 notable events occurred in less than 11 minutes on September 8, 2011. The inquiry's SOE team established a precise and accurate sequence of outage-related events to form a critical building block for the other parts of the inquiry. It provided, for example, a foundation for the root cause analysis, computer-based simulations, and other event analyses. Although entities time-stamp much of the data related to specific events, their time-stamping methodologies vary, and not all of the time-stamps were synchronized to the National Institute of Standards and Technology (NIST) standard clock in Boulder, Colorado. Validating the precise timing of specific events became a time-consuming, important, and sometimes difficult task. The availability of global positioning system (GPS)-time synchronized PMU data on frequency, voltage, and related power angles made this task much easier than in previous blackout inquiries and investigations.

To develop the SOE, the SOE team started by resolving discrepancies between the multiple sources of data, sign convention inconsistencies, and incorrect data. The SOE team then developed an events database starting with all known events and times. Initial sources for the development of the database included preliminary reports filed by the affected entities as well as initial responses to data requests. The team then examined each record in the database to verify event times using available SCADA and PMU data. As the frequency, line flow, or voltage data suggested that additional events might have occurred on the system, the team added other possible events and verified them through additional data requests.

The SOE team developed multiple iterations of an SOE narrative document based on the database and the available SCADA and PMU data. Some iterations of the SOE narrative required that more data be requested of affected entities, and ultimately multiple data requests were sent to each entity. After the team completed the SOE narrative, the inquiry's Modeling and Simulation team verified the SOE using power flow, voltage stability, and dynamic stability analyses.

## Power Flow and Dynamics Analysis

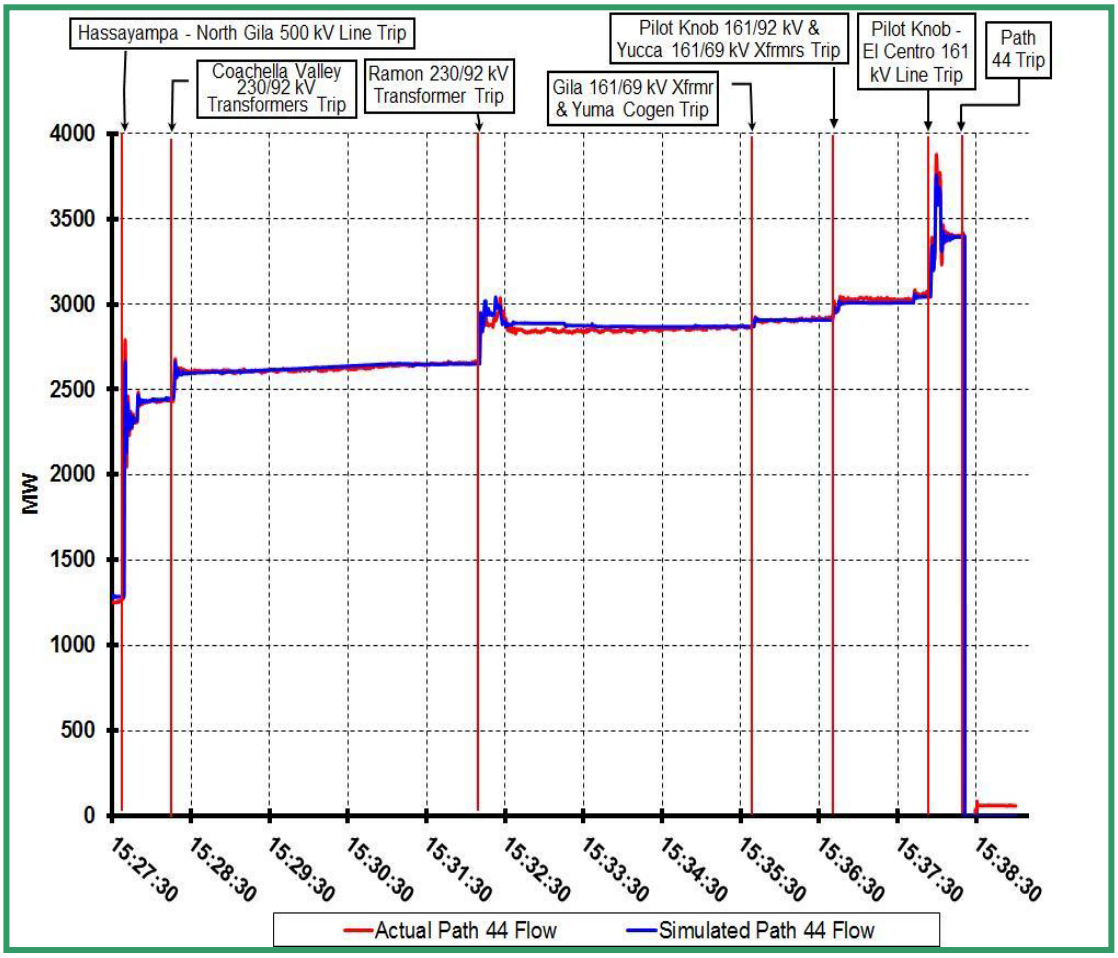
The inquiry's Modeling and Simulation team, after validating the SOE, considered several "what if" scenarios. The Modeling and Simulation team's work is described in more detail in Appendix D. Power flow analyses study power systems under quasi-steady-state conditions by matching load and generation to obtain voltage magnitude and angle at each bus and the real and reactive power flowing through each transmission facility. Dynamic stability analyses study the impact of disturbances on frequency, voltage, and rotor angle stability, and determine whether transients in the power system are stable, thus allowing the power system to return to a quasi-steady-state operating condition following a disturbance.[21]

As the first step in performing power flow and dynamic stability analyses, the Modeling and Simulation team developed and benchmarked a modeling case of system conditions prior to the event. The team started with the WECC heavy summer base case and made adjustments based on State Estimator snapshots, EMS data, actual generation and schedules, PMU data, and a base case prepared by a separate team (led by CAISO) that studied the event. The team further adjusted and benchmarked the base case using SCADA and PMU data to match the system conditions for the entire event. The team devoted considerable time and effort to resolving discrepancies between the various sources of data to best calibrate the modeling case to actual measured data. As illustrated by ***Figure* 1**, on the next page, and described in more detail in Appendix D, the Modeling and Simulation team achieved a significant degree of accuracy. This figure compares Path 44 flows simulated by the Modeling and Simulation team to actual Path 44 PMU data.

After developing and benchmarking a valid case, the Modeling and Simulation team simulated the entire SOE using both power flow and dynamic simulations. This replication of the SOE established the validity of the model and enabled meaningful simulation of several alternative scenarios, developed to answer "what if" questions regarding the event. For example, the inquiry considered what would have happened if some of the affected entities had dispatched generation at certain locations during the event, if overload relays had been set at different levels, or if RASs, Safety Nets, or other SPSs had been designed or operated differently.

[21] Transient stability refers to the ability of synchronous generators to move to a new quasi-steady-state operating point while remaining synchronized after the system experiences a disturbance.

**Figure 1: Comparison of Actual and Simulated Path 44 Flows**




## Outreach Sessions

After developing a list of preliminary findings and recommendations, the inquiry conducted outreach meetings with various industry associations and groups, including CAISO, WECC, the American Public Power Association (APPA), the North American Transmission Forum (NATF), the Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), and representatives from Regional Entities (REs), Regional Transmission Organizations, and Independent System Operators. Team members shared the inquiry's preliminary findings and recommendations on a non-public basis with members of these organizations to obtain feedback and, with respect to the recommendations, input as to their practicality and feasibility. The inquiry considered the feedback and input provided by these organizations and incorporated much of it into the findings and recommendations included in this report.

## B. System Overview

This subsection provides an overview of: (1) the Western Interconnection and its position in the North American electric grid; (2) the reliability entities responsible for operating the grid; (3) a description of the affected entities; and (4) a discussion of the interconnected nature of these entities.

### The Western Interconnection and Its Position in the North American Electric Grid

NERC shares its mission of ensuring the reliability of the BPS in North America with eight REs through a series of delegation of authority agreements. WECC is the designated RE responsible for coordinating and promoting BPS reliability in the Western Interconnection. In its capacity as the RE, WECC monitors and enforces compliance with Reliability Standards by the users, owners, and operators of the BPS. WECC also functions as an Interconnection-wide planning facilitator, aiding in transmission and resource integration planning at the request of its members, as well as a provider of data, analysis, and studies related to transmission planning and reliability issues.

The WECC region extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, the states of Washington, Oregon, California, Idaho, Nevada, Utah, Arizona, Colorado, Wyoming, and portions of Montana, South Dakota, New Mexico, and Texas. See ***Figure 2***, on the next page. The WECC region is nearly 1.8 million square miles in size, has over 126,000 miles of transmission, and serves a population of 78 million. WECC contains 37 BAs and 53 TOPs. Due to the diverse characteristics of this extensive region, WECC encounters unique challenges in day-to-day coordination of its interconnected system. WECC is tied to the Eastern Interconnection through a number of high-voltage direct current transmission ties.

WECC also operates two RC offices that provide situational awareness and real-time monitoring of the entire Western Interconnection. WECC RC was an affected entity, and will be discussed with other affected entities below.

**Figure 2: Map of WECC Region**




## Reliability Responsibilities

NERC categorizes the entities responsible for planning and operating the BPS in a reliable manner into multiple functional entity types. The NERC functional entity types most relevant to this event are BAs, TOs, TOPs, Generator Operators (GOPs), Planning Coordinators (PCs), Transmission Planners (TPs), and RCs. These functions are described in more detail in NERC's Reliability Functional Model.[22] Some of the affected entities conduct multiple reliability functions.

- **Balancing Authority**

The BA integrates resource plans ahead of time, maintains in real time the balance of electricity resources (generation and interchange) and electricity demand or load within its footprint, and supports the Interconnection frequency in real time. There

[22] NERC Reliability Functional Model, Version 5, http://www.nerc.com/files/Functional_Model_V5_Final_2009Dec1.pdf.

are 37 BAs in the WECC footprint. The following five BAs were affected by the event: APS, IID, WALC, CAISO, and CFE.

- **Transmission Owner, Transmission Operator and Generator Operator**

The TO owns and maintains transmission facilities. The TOP is responsible for the real-time operation of the transmission assets under its purview. The TOP has the authority to take corrective actions to ensure that its area operates reliably. The TOP performs reliability analyses, including seasonal and next-day planning and RTCA, and coordinates its analyses and operations with neighboring BAs and TOPs to achieve reliable operations. It also develops contingency plans, operates within established SOLs, and monitors operations of the transmission facilities within its area. There are 53 TOPs in the WECC region. The following seven TOPs were affected by the event: APS, IID, WALC, CAISO, CFE, SDG&E, and SCE. The GOP operates generating unit(s) and performs the functions of supplying energy and other services required to support reliable system operations, such as providing regulation and reserve capacity.

- **Planning Coordinator**

The PC is responsible for coordinating and integrating transmission facility and service plans, resource plans, and protection systems.[23]

- **Transmission Planner**

The TP is responsible for developing a long-term (generally one year and beyond) plan for the reliability of the interconnected bulk transmission systems within its portion of the Planning Coordinator Area.

- **Reliability Coordinator**

The RC and TOP have similar roles, but different scopes. The TOP directly maintains reliability for its own defined area. The RC is the "highest level of authority" according to NERC, and maintains reliability for the Interconnection as a whole. Thus, the RC is expected to have a "wide-area" view of the entire Interconnection, beyond what any single TOP could observe, to ensure operation within IROLs.

The RC oversees both transmission and balancing operations, and it has the authority to direct other functional entities to take certain actions to ensure reliable

[23] PCs are the same as Planning Authorities (PAs) with respect to NERC registration and the Reliability Standards.

operation. The RC, for example, may direct a TOP to take whatever action is necessary to ensure that IROLs are not exceeded.[24] The RC performs reliability analyses including next-day planning and RTCA for the Interconnection, but these studies are not intended to substitute for TOPs' studies of their own areas. Other responsibilities of the RC include responding to requests from TOPs to assist in mitigating equipment overloads. The RC also coordinates with TOPs on system restoration plans, contingency plans, and reliability-related services.

## Descriptions of Affected Entities

The following entities were affected by the September 8th event:

- **WECC RC**

In its capacity as the RC, WECC is the highest level of authority responsible for the reliable operation of the BPS in the Western Interconnection. WECC RC oversees the operation of the Western Interconnection in real time, receiving data from entities throughout the entire Interconnection, and providing high-level situational awareness for the entire system. WECC RC can direct the entities it oversees to take certain actions in order to preserve system reliability. Although WECC is both an RE and an RC, these two functions are organizationally separated.

- **Imperial Irrigation District**

IID, which encompasses the Imperial Valley, the eastern part of Coachella Valley in Riverside County, and a small portion of San Diego County, in California, owns and operates generation, transmission, and distribution facilities in its service area to provide comprehensive electric service to its customers. Thus, IID is a vertically integrated utility. IID's generation consists of hydroelectric units on the All-American Canal as well as oil-, nuclear-, coal-, and gas-fired generation facilities, with a total net capability of 514 MW. IID purchases power from other electric utilities to meet its peak demands in summer, which can exceed 990 MW. IID's transmission system consists of approximately 1,400 miles of 500, 230, 161, and 92 kV lines, as well as 26 transmission substations. Among other NERC registrations, IID is a TOP, BA, and TP responsible for resource and transmission planning, load balancing, and frequency support for its footprint.

[24] For example, IRO-005-1 R.5 requires that "[e]ach [RC] shall identify the cause of any potential or actual SOL or IROL violations. The [RC] shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The [RC] shall be able to utilize all resources, including load shedding, to address an IROL violation."

- **Arizona Public Service**

APS is a vertically integrated utility that serves a 50,000 square mile territory spanning 11 of Arizona's 15 counties. Among other NERC registrations, APS is the TOP and BA for its territory. APS engages in both marketing and grid operation functions, which are separated. APS owns and operates transmission facilities at the 500 (including H-NG), 345, 230, 115, and 69 kV levels, and owns approximately 6,300 MW of installed generation capacity. APS's 2011 peak load was 7,087 MW.

- **Western Area Power Administration – Lower Colorado**

WALC is one of the four entities constituting the Western Area Power Administration, a federal power marketer within the United States Department of Energy. WALC operates in Arizona, Southern California, Colorado, Utah, New Mexico, and Nevada, and is registered with NERC as a BA, TOP, and PC for its footprint. As a net exporter of energy, WALC's territory has over 6,200 MW of generation, serving at most 2,100 MW of peak load. A majority of WALC's generation is federal hydroelectric facilities, with the balance consisting of thermal generation owned and operated by independent power producers. WALC also operates an extensive transmission network within its footprint, and is interconnected with APS, SCE, and nine other balancing areas.

- **San Onofre Nuclear Generating Station**

SONGS is a two-unit nuclear generation facility capable of producing approximately 2,200 MW of power, and is located north of San Diego.[25] SONGS produces approximately 19% of the power used by SCE customers and 25% of the power used by SDG&E customers. SONGS is jointly owned by SCE (78.21%), SDG&E (20%), and the City of Riverside (1.79%). SCE, as TO and GO, is responsible for ensuring the safe and reliable operation of SONGS within the grid.

- **California Independent System Operator**

CAISO runs the primary market for wholesale electric power and open-access transmission in California, and manages the high-voltage transmission lines that make

[25] SONGS is currently in the midst of an extended outage. According to a March 2012 press release by CAISO, if both SONGS units remain offline for the summer, "San Diego and portions of the Los Angeles Basin may face local reliability challenges." http://www.caiso.com/Documents/SummerGridOutlook Complicated-PossibleExtendedOutage-NuclearPowerPlant.pdf.

up approximately 80% of California's power grid. CAISO operates its market through day-ahead and hour-ahead markets, as well as scheduling power in real time as necessary. Among other registrations, CAISO is PC and BA for most of California, including the city of San Diego. It also acts as TOP for several entities within its footprint, including SDG&E and SCE. CAISO likewise engages in modeling and planning functions in order to ensure long-term grid reliability, as well as identifying infrastructure upgrades necessary for grid function.

- **San Diego Gas and Electric**

SDG&E is a utility that serves both electricity and natural gas to its customers in San Diego County and a portion of southern Orange County, and is the primary utility for the city of San Diego. SDG&E owns relatively little generation—approximately 600 MW—although generation owned by others in its footprint brings the total generation capacity of the area above 3,350 MW. Peak load for the area can exceed 4,500 MW in the summer. SDG&E also operates an extensive high-voltage transmission network at the 500, 230, and 138 kV levels. SDG&E, operating as a TOP within CAISO's BA footprint, has delegated part of its responsibilities as a TOP to CAISO.

- **Comisión Federal de Electricidad – Baja California Control Area**

CFE is the only electric utility in Mexico, servicing up to 98% of the total population. CFE's Baja California Control Area is not connected to the rest of Mexico's electric grid but is connected to the Western Interconnection. CFE's Baja California Control Area covers the northwest corner of Mexico, including the cities of Tijuana, Rosarito, Tecate, Ensenada, Mexicali, and San Luis Rio Colorado. CFE's Baja California Control Area operates transmission systems at the 230, 161, 115, and 69 kV levels, and owns 2,039 MW of gross generating capacity and the rights to a 489 MW independent power producer within the Baja California Control Area. CFE's Baja California Control Area had a net peak load of 2,184 MW for summer 2010. CFE's Baja California Control Area is connected at the 230 kV level with SDG&E through two transmission lines on WECC Path 45. CFE functions as the TO, TOP, and BA for its Baja California Control Area under the oversight of WECC RC. For the remainder of this report, "CFE" refers only to its Baja California Control Area.

- **Southern California Edison**

SCE is a large investor-owned utility which provides electricity in central, coastal, and southern California. SCE is a wholly-owned subsidiary of Edison International, which is also based in California. Among other NERC registrations, SCE operates as a

TOP within CAISO's BA footprint, and has delegated part of its responsibilities as a TOP to CAISO. SCE is also registered as TP, and is responsible for the reliability assessments of the SONGS separation scheme. SCE owns 5,490 circuit miles of transmission lines, including 500, 230, and 161 kV lines. SCE also operates a subtransmission system of 7,079 circuit miles at the 115, 66, 55, and 33 kV levels. Of the affected entities, SCE is interconnected with APS, IID, and SDG&E at various transmission voltage levels. SCE owns over 5,600 MW of generation, including a majority share in SONGS, and its peak load exceeds 22,000 MW. Along with SONGS staff, SCE is responsible for the safe and reliable operation of the nuclear facility.

## Interconnected Operations

The September 8th event exemplifies the interconnected operations of three parallel transmission corridors through which power flows into the area where the blackout occurred. Typically, BAs, through dispatch, balance the flows on these corridors so that no one corridor experiences overloads in an N-1 situation, but this did not happen on September 8th.

The first transmission corridor consists of the 500 kV H-NG, which is one of several transmission lines forming Path 49 ("East of River"). Along with two 500 kV lines, one from North Gila to Imperial Valley and another from Imperial Valley to Miguel, they form the SWPL. The majority of the SWPL is geographically parallel to the United States-Mexico border. The SWPL meets the SDG&E and IID systems at the Imperial Valley substation. This is shown as the "H-NG Corridor" on ***Figure 3***, on the next page.

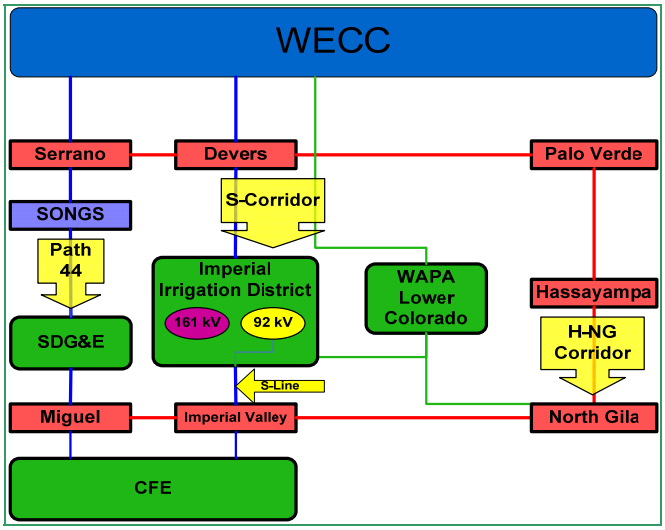
The second corridor is Path 44, also known as "South of SONGS," operated by CAISO. This corridor includes the five 230 kV lines in the northernmost part of the SDG&E system that connect SDG&E with SCE at SONGS.

The third transmission corridor, shown as the "S Corridor" on Figure 3, consists of lower voltage (230, 161 and 92 kV) facilities operated by IID and WALC in parallel with those of SCE, SDG&E, and APS. The only major interconnection between IID and SDG&E is through the 230 kV "S" Line, which connects the SDG&E/IID jointly-owned Imperial Valley Substation (operated by SDG&E) to IID's El Centro Switching Station. The S Line interconnects the southern IID system with SDG&E and APS at Imperial Valley, which is also a terminus for the SWPL segment from Miguel and the SWPL segment from North Gila. WALC is connected to the SCE system and the rest of the Western Interconnection by 161 kV ties at Blythe, to IID by the 161 kV tie between

WALC's Knob and IID's Pilot Knob substations, and to APS by a 69 kV tie via Gila at North Gila.

The eastern end of the SWPL, which terminates at APS's Hassayampa hub, is connected to SCE via a 500 kV line that connects APS's Palo Verde and SCE's Devers substations. The northern IID system is connected to SCE's Devers substation via a 230 kV transmission line that connects from Devers to IID's CV substation. These connections, along with SDG&E's connection to SCE via Path 44's terminus at SONGS, make the SWPL, Path 44, and IID's and WALC's systems operate as electrically parallel transmission corridors.[26] The following simplified diagram illustrates the interconnected nature of these three parallel corridors. Red lines represent 500 kV, blue lines represent 230 kV, and green lines represent 161 kV.

**Figure 3: Three Parallel Corridors**




[26] Power transfers from APS to SDG&E and CFE generally flow across the SWPL, but, due to parallel path flows, also known as loop flows, some of the power transfers flow through IID's and WALC's systems. Loop flow refers to power flow along any transmission paths that are in parallel with the most direct geographic or contract path.

# III. SEQUENCE OF EVENTS[27]

The 11 minutes of the disturbance are divided into seven phases, as highlighted in ***Figure 4***, on the next page. This figure displays the progressive loading of the five 230 kV tie lines from SCE north of San Diego that form Path 44. This section describes how the loss of various elements during an 11-minute period combined to exceed the 8,000 amp setting on the SONGS separation scheme. After sustained loading on Path 44 above 8,000 amps, the SONGS separation scheme operated. Once the SONGS separation scheme operated, San Diego and IID, CFE, and Yuma, Arizona, blacked out in less than 30 seconds. This section is divided into subsections for each phase, including the key events during the phase, their causes and effects, and, where relevant, what the affected entities knew and did not know as the events were unfolding. Each section begins with a brief summary. A final subsection describes restoration efforts after the blackout.

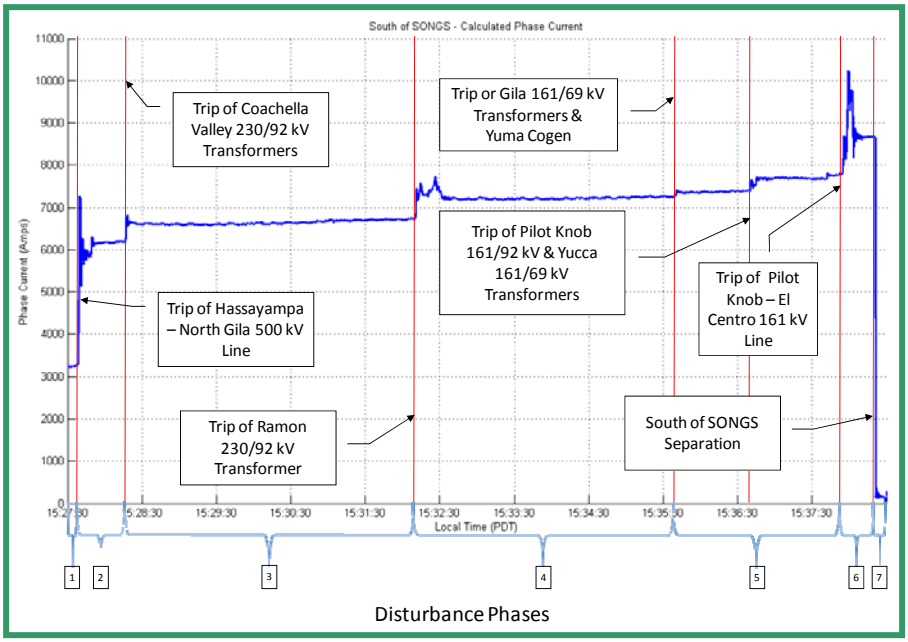
A set of graphics is included at the end of each phase to demonstrate the effect of the events during the phase. The first graphic in each set depicts the aggregate loading in amps on the five South of SONGS lines.[28] The bottom portion of the graphic shows all of the phases, while the majority of the graphic shows an expanded view of the phase being discussed. The second graphic in each set represents the loading on key facilities after each phase. The third graphic in each set shows how power flows redistributed through Arizona, Southern California, and Mexico after each phase. Phases 6 and 7 have multiple power flow graphics. Phases 1 and 7 include only the second and third type of graphics.

[27] All times are in Pacific Daylight Time (PDT) unless otherwise noted. Times are listed to millisecond (three decimal places) or tenth-of-second (decimal place) accuracy when possible. If milliseconds or tenth-of-seconds are not listed, the event is reconciled to the nearest second.

[28] Path 44 flows (complex power in volt amperes, current in amps) were calculated from SONGS PMU data. Those readings differ somewhat from disturbance monitoring equipment that was unavailable until completion of the inquiry's analysis. The differences are explained by variances in how some minor auxiliary loads are measured and in measurement equipment tolerances.

The following figure shows all seven phases of the disturbance.

**Figure 4: Seven Phases of the Disturbance**




## A. Phase 1: Pre-Disturbance Conditions

### Phase 1 Summary:

- Timing: September 8, 2011, before H-NG trips at 15:27:39
- A hot, shoulder season day with some generation and transmission maintenance outages
- Relatively high loading on some key facilities: H-NG at 78% of its normal rating, CV transformers at 83%
- 44 minutes before loss of H-NG, IID's RTCA results showed that the N-1 contingency loss of the first CV transformer would result in an overload of the second transformer above its trip point
- An APS technician skipped a critical step in isolating the series capacitor bank at the North Gila substation

September 8, 2011, was a relatively normal, hot day in Arizona, Southern California, and Baja California, Mexico, with heavy power imports into Southern California from Arizona. In fact, imports into Southern California were approximately 2,750 MW, just below the import limit of 2,850 MW. September is generally considered a "shoulder" season, when demand is lower than peak seasons and generation and transmission maintenance outages are scheduled. By September 8th, entities throughout the WECC region, including some of the affected entities, had begun

generation and transmission outages for maintenance purposes. For example, on September 8th maintenance outages included over 600 MW of generation in Baja California[29] and two 230 kV transmission lines in SDG&E's territory. However, there were no major forced outages or major planned transmission outages that would result in a reduction of the SOLs in the area.

- **Pre-Disturbance Conditions in IID**

Despite September being considered a shoulder month, temperatures in IID's service territory reached 115 degrees on September 8th.[30] IID's load headed toward near-peak levels of more than 900 MW, which required it to dispatch local combustion turbine generation in accordance with established operating procedures. Prior to the event, loading on IID's CV transformers reached approximately 125 megavolt amperes (MVA) per transformer, which is approximately 83% of the transformers' normal limit. Loading on IID's Ramon transformer was 153 MVA, which is approximately 68% of its normal limit.

IID's S Line ties IID to SDG&E, and through SDG&E, to generation in Mexico at La Rosita. It also ties CFE and IID, through SDG&E's La Rosita international transmission line. Before the event, IID was importing power on the S Line, and thus power was flowing northward from the jointly owned Imperial Valley substation to IID's El Centro substation. Flows on the S Line would reverse multiple times during the event. When power flowed on the S Line from south to north, the implication was that IID was supplied radially through SDG&E. Throughout the event, as power flowed from north to south, the implication was that flows intended for SDG&E and/or CFE were moving through IID's system. Eventually, in Phase 6, south to north flows on the S Line would activate a RAS that would ultimately trip more than 400 MW of generation at La Rosita and the S Line, thereby worsening the loading on Path 44.

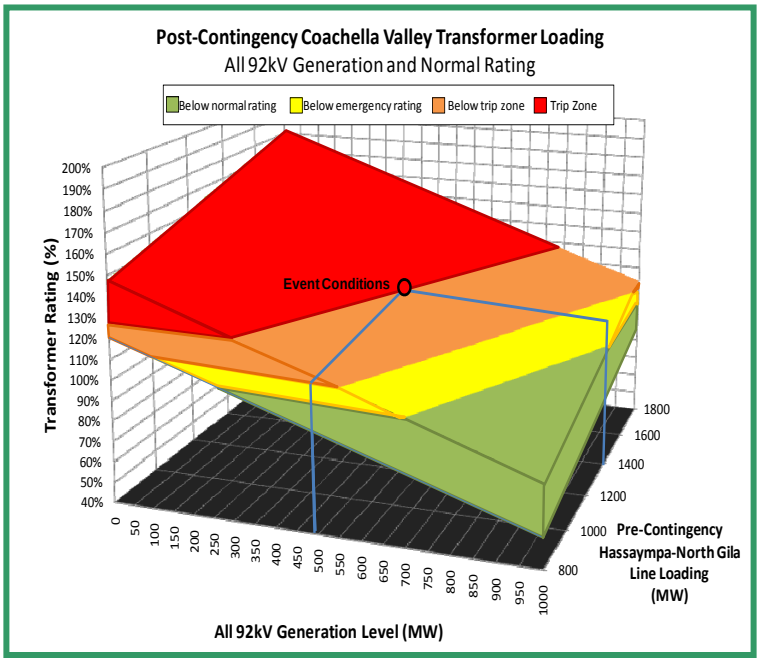
Forty-four minutes prior to the loss of H-NG on September 8, 2011, IID's RTCA results showed that the N-1 contingency loss of the first CV transformer would result in an overload of the second transformer above its trip point. The IID operator was not actively monitoring the RTCA results and, therefore, was not alerted to the need to take any corrective actions. At the time of the event, IID operators did not keep the RTCA

[29] The generation was known as Termoelectrica de Mexicali, and will be hereafter referred to as "TDM." It is also shown as "TDM" on the Map of Affected Entities.

[30] According to IID, the temperature in El Centro, California reached 115 degrees on September 8, 2011.

display visible, and RTCA alarms were not audible. By reducing loading on the CV transformers at this pre-event stage, the operator could have mitigated the severe effects on the transformers that resulted when H-NG tripped. Since the event, IID has required, and now requires, its operators to have RTCA results displayed at all times. The loading on IID's CV transformers was pivotal to this event. Loading on the CV transformers is influenced by: (1) the pre-contingency flow on H-NG; (2) load and generation in IID's 92 kV network; (3) flow on the S Line; and (4) to a lesser extent, generation connected to the Imperial Valley substation. See Figure 5, below.

**Figure 5: Post-Contingency CV Transformer Loading Based on All IID 92 kV Generation**




- **Pre-Disturbance Conditions in CFE**

At 15:07 CFE's Presidente Juarez Unit 11 tripped, which required CFE to activate its Baja California Control Area contingency reserves to restore its ACE. At 15:15 PDT CFE returned its ACE to where it had been before the unit tripped. Although still complying with the spinning reserve requirements, CFE was short on non-spinning reserve, with all of its available resources in use or already deployed.

### Pre-Disturbance Focus of WECC RC

Prior to the event, WECC RC operators were monitoring unscheduled flow on several paths in Northern California. WECC RC did not view any of the scheduled transmission or generation outages as significant. As illustrated by the chart below, two minutes before the event (at 15:25), major paths in the blackout area were operating below their Path ratings:

| Major Paths in the Blackout Area | Established Path Ratings/Flow Limits | Path Loadings in MW and % |
|---|---|---|
| 500 kV H-NG<br>(Part of Corridor 1 into blackout area) | 1,800 MW[31] | 1,397 MW<br>78% |
| Path 44<br>(Corridor 2 into blackout area) | 2,200 MW[32] | 1,302 MW<br>59% |
| 230 kV S Line<br>(Part of Corridor 3 into blackout area) | 239 MW | 90 MW<br>38% |
| SDG&E Import SOL | 2,850 MW | 2,539 MW<br>89% |
| SDG&E to CFE Path 45 | 800 MW S-N;<br>408 MW N-S | 241 MW N-S<br>60% |

### Pre-Disturbance Conditions in APS

APS manages H-NG, a segment of the SWPL. At 13:57:46, the series capacitors[33] at APS's North Gila substation were automatically bypassed due to phase imbalance protection. APS sent a substation technician to perform switching to isolate the capacitor bank. The technician was experienced in switching capacitor banks, having performed switching approximately a dozen times. APS also had a written switching order for the specific H-NG series capacitor bank at North Gila. After the APS system operator and the technician verified that they were working from the same switching order, the operator read steps 6 through 16 of the switching order to the technician. The

[31] The limit of H-NG is a portion of the rating of Path 49. The inquiry determined that the limit is approximately 1,800 MW.

[32] With one segment of the SWPL out, the limit increases to 2,500 MW.

[33] A series capacitor is a power system device that is connected in series with a transmission line. It increases the transfer capability of the line by reducing the voltage drop across the line and by increasing the reactive power injection into the line to compensate for the reactive power consumption. In simple terms, a 50% series compensated line means it has the equivalent of 50% of the electric distance (or impedance) of the otherwise uncompensated line.

technician repeated each step after the operator read it, and the operator verified the technician had correctly understood the step. The technician then put a hash mark beside each of steps 6 through 16 to indicate that he was to perform those steps. The technician did not begin to perform any of steps 6 through 16 until after all steps had been verified with the system operator.

The technician successfully performed step 6, verifying that the capacitor breaker was closed, placing it in "local" and tagging it out with "do not operate" tags. However, because he was preoccupied with obtaining assistance from a maintenance crew to hang grounds[34] for a later step, he accidentally wrote the time that he had completed step 6 on the line for step 8. For several minutes, he had multiple conversations about obtaining assistance to hang the grounds. He then looked back at the switching order to see what step should be performed next. His mistake in writing the time for step 6 on the line for step 8 caused him to pick up with step 9, rather than step 7.[35] Thus, he skipped two steps, one of them the crucial step (step 8) of closing a line switch to place H-NG in parallel with the series capacitor bank. This step would bypass the capacitor bank, resulting in almost zero voltage across the bank and virtually zero current through the bank. Because he skipped step 8, when he began to crank open the hand-operated disconnect switch to isolate the capacitor bank, it began arcing under load.[36] He could not manage to toggle the gearing on the switch to enable its closure, so he stayed under the arcing 500 kV line, determined to crank open the switch far enough to break the arc, thereby preventing additional damage to the equipment. ***Figure* 6**, on the next page, is a schematic of the APS series capacitor bank, showing steps seven through nine.

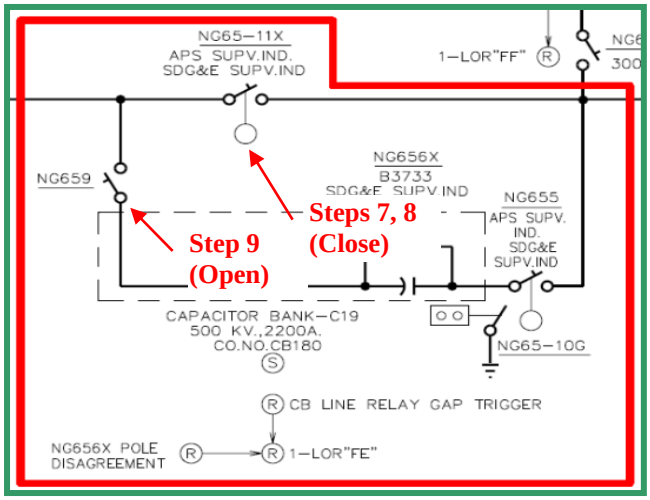
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[34] Grounds are temporary protective connections that are run from conductive parts of lines, structures, and equipment, to earth or some other grounding system that substitutes for earth. If the isolated equipment is accidentally energized, grounds are intended to: (1) limit the voltage rise at the worksite to a safe value; and (2) provide a pathway for fault current to flow, thereby allowing upstream protective devices to trip.

[35] In human performance analysis, this is known as a "place keeping" error, by failing to physically mark steps as they are completed.

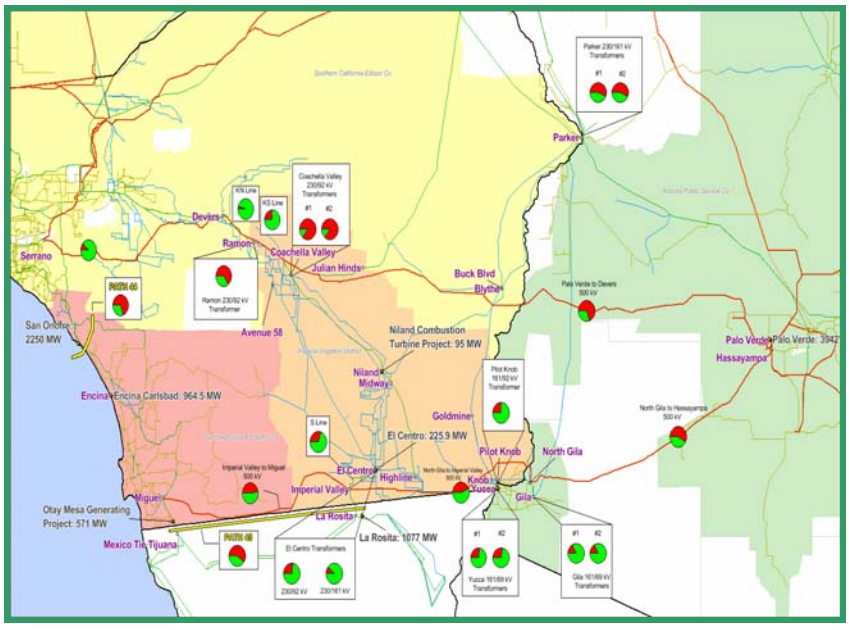
[36] An electric arc is a luminous discharge of current that is formed when a strong current jumps a gap in a circuit.

**Figure 6: APS Series Capacitor Bank**

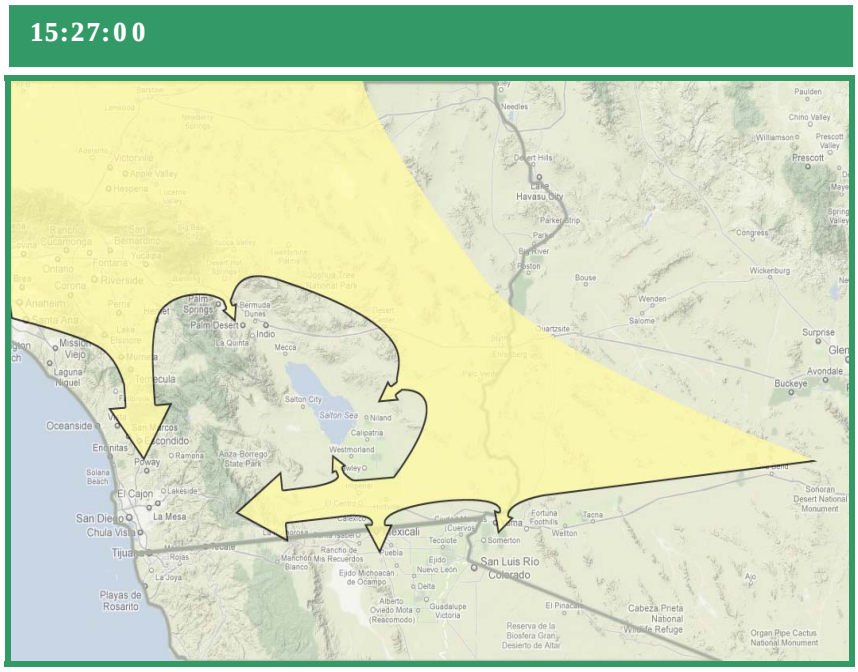



## Phase 1 Graphics[37]

**Pre-disturbance (000)**




[37] For the dial graphics shown here, green indicates available capacity on the facility, red indicates that the facility is fully loaded to its normal limit, blue indicates the amount by which the facility is overloaded, and gray indicates that the facility has tripped or load has been lost. For the power flow graphics, black borders indicate islanding, and gray areas bounded by black are those where load was lost.




## B. Phase 2: Trip of the Hassayampa-North Gila 500 kV Line

### Phase 2 Summary:

- Timing: 15:27:39 to 15:28:16, just before CV transformer No. 2 trips
- H-NG trips due to fault; APS operators believe they will restore it quickly and tell WECC RC
- H-NG flow redistributed to Path 44 (84% increase in flow), IID, and WALC systems
- CV transformers immediately overloaded above their relay setting
- At end of Phase 2, loading on Path 44 at 5,900 out of 8,000 amps needed to initiate SONGS separation scheme

At 15:27:39, the arc that had developed on each phase of the disconnect switch lengthened as the switch continued to open, to the point where two phases came into contact. This caused H-NG to trip to clear this phase-to-phase (A to C) fault. The high-speed protection system correctly detected the fault and tripped the line in 2.6 cycles (43 milliseconds). After discussion with the technician, APS operators erroneously believed that they could return the line to service in approximately minutes, even though they had no situational awareness of a large phase angle difference caused by the outage. More time would have been needed to redispatch generation to reduce the phase angle difference to the allowed value. APS system operators informed CAISO, Salt River Project (SRP), and WECC RC that the line would be reclosed quickly, even though they were unaware that this was not possible because of the large phase angle difference that

existed between Hassayampa and North Gila. The inquiry's simulation indicates that the post-contingency angular difference was beyond the allowed North Gila synch-check relay reclosing angle setting of 60 degrees, and there would not have been adequate generation for redispatch to reduce the phase angle difference to within the allowed value. APS operators were only able to see the angular difference on EMS displays after isolating the North Gila capacitor bank and re-energizing H-NG from the Hassayampa substation (before closing at North Gila).

H-NG, which has a flow limit of 1,800 MW[38] with a 30 minute emergency rating of 2,431 MW, was carrying 1,391 MW flowing from east to west along the SWPL at the time of the trip. As a result of the line trip, flows redistributed across the remaining lines into the San Diego, Imperial Valley, and Yuma areas. The IID and WALC systems, located between the two parallel high voltage Paths, were forced to carry approximately 23% of the flow that had initially been carried by H-NG. The majority of the flow diverted to Path 44, as discussed below.

Immediately after the loss of H-NG, the loading on both of IID's CV transformers increased to 130% of their normal rating and 118.5% of their emergency rating. The time overcurrent relays on the CV transformers picked up because the current flow was above the overcurrent relay setting, and began timing according to their very inverse[39] time delay. The CV transformers would both trip within 40 seconds of the loss of H-NG. At the same time, loading on IID's Ramon 230/92 kV transformer increased to 94% of its normal rating and 85% of its emergency rating. Three seconds after the loss of H-NG, SCADA metering for the CV transformer banks stopped recording accurate readings due to remote terminal unit (RTU) exceeding maximum scale. IID and WECC RC no longer had accurate information about or situational awareness of the loading on these important transformers.

IID also experienced increased loading on several of its 161 kV lines immediately after the loss of H-NG: Blythe-Niland and Knob-Pilot Knob loading increased by 49% and 55%, respectively. Flows on IID's S Line reversed from south to north (SDG&E to

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**38** *See* footnote 31, *supra*.

**39** "Very inverse" describes the time/current characteristic of the relays' time delay which is inversely proportional to the current magnitude sensed by the relay. That is, the greater the current, the less time before the relay will trip.

IID) to north to south (IID to SDG&E) during this phase of the event, indicating that flows intended for SDG&E were being routed through IID's 161 and 92 kV systems. While IID was aware of the flow changes on the S Line, it was unable to see the loss of H-NG in real time.

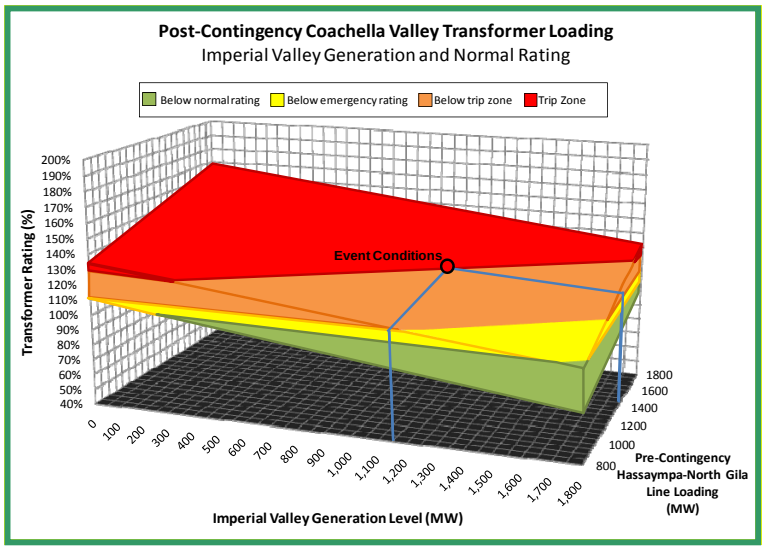
Flows on WALC's Gila 161/69 kV transformers increased from approximately 12 MVA to 60 MVA, still well below their normal limits of 75 MVA each, but indicative of the sudden increase in flows on WALC's system just after the loss of H-NG. WALC also experienced significant voltage drops on its 161 kV system, particularly at Blythe (6.9% drop) and Kofa (6.7% drop) substations, due to the increased flows on that system.

The loss of H-NG interrupted the southern 500 kV path into San Diego. The majority of the flow diverted to the northern entry to SDG&E, Path 44. Flow on Path 44 increased by approximately 84%, from 1,293 MW to 2,362 MW. This flow equates to a tie current of 5,900 amps relative to the 8,000 amps required to initiate the SONGS separation scheme.

Because so much of the flow on H-NG was intended for San Diego, the inquiry considered whether increasing internal generation in SDG&E's area would have avoided the cascading outages.[40] ***Figure 7***, on the next page, illustrates post-contingency loading on the CV transformers based on pre-contingency loading on H-NG and the generation level at IID's and SDG&E's jointly owned Imperial Valley substation. The red area on the graph indicates the large zone in which loading below H-NG's 1,800 MW SOL would load the CV transformers above their trip point. This area demonstrates the non-secure N-1 operating point of the CV transformers. It shows that the operating conditions that would reduce the loading on the transformer are: increased generation at Imperial Valley, reduced flow on H-NG before it tripped, or both. For example, the graph indicates that for the same amount of transfer on H-NG, additional generators connected at Imperial Valley would reduce the post-contingency loading on the CV transformers.

[40] The inquiry's analysis is not intended to suggest specific generation adjustments that could have been made by specific entities on September 8, 2011, but rather to show the extent to which the affected entities are interdependent.

**Figure 7 : Post-Contingency CV Transformer Loading Based on Imperial Valley Generation**




In general, adding generation in San Diego, CFE, or Imperial Valley and backing down generation in APS's system (east of Path 49) would reduce the loading on IID's 92 kV system for the loss of H-NG. For example, an additional 600 MW of generation at Imperial Valley and a reduction of generation in APS's system by the same amount would have reduced the pre-contingency loading on H-NG by 20% and improved the post-contingency voltage in WALC's Blythe area by approximately 4%. Under this condition, the loading on the CV transformers for the loss of H-NG would be approximately 111% of their normal rating (166 MVA), well below their trip setting of 127%. This is a further demonstration of the importance of including all facilities when deriving SOLs.

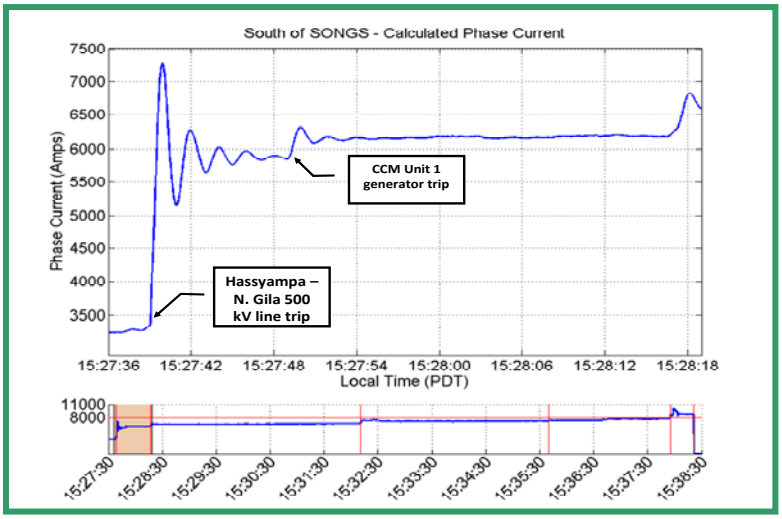
After seeing the alarm for the loss of H-NG, the WECC RC operator promptly called the line's operator, APS. APS told WECC RC it could get H-NG restored within minutes. While WECC RC was monitoring Rated Paths, it took no action specific to Path 44, believing it would take five or ten minutes for APS to restore H-NG. As the entire event took only 11 minutes, WECC RC did not issue any directives in connection with the loss of H-NG.

Shortly after H-NG tripped, at 15:27:49, one of the combustion turbines at CFE's Central La Rosita substation tripped while producing 156 MW. This trip may have been

triggered by transients[41] caused by the initial fault at North Gila and subsequent trip of H-NG. Loss of this unit further increased the flow on Path 44, raising the current to 6,200 amps out of the 8,000 needed to initiate the SONGS separation scheme. However, the La Rosita trip alone was not significant in causing the cascading that followed.[42] CFE was also unaware in real time that H-NG had tripped. After losing the Central La Rosita unit, CFE was unable to recover its ACE with its own resources, and at 15:30, it requested 158 MW of emergency assistance from CAISO for the remainder of the hour.

## Phase 2 Graphics

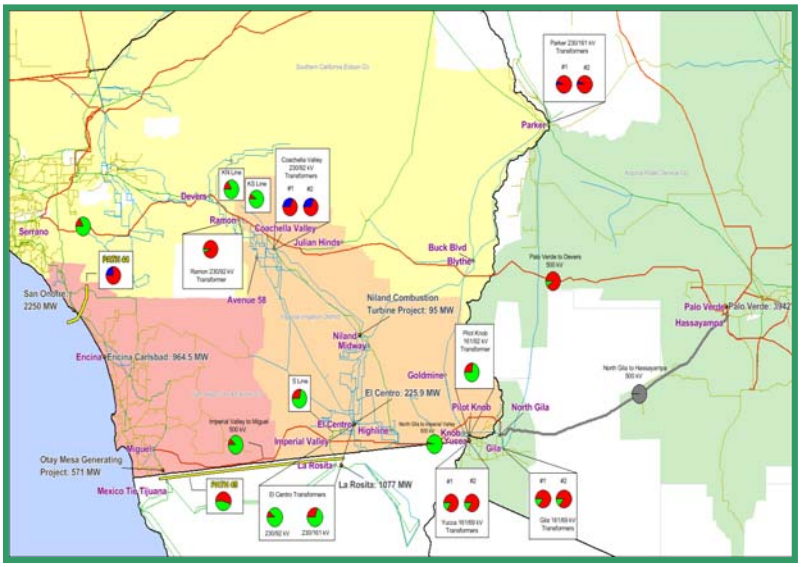
**South of SONGS – Calculated Phase Current**



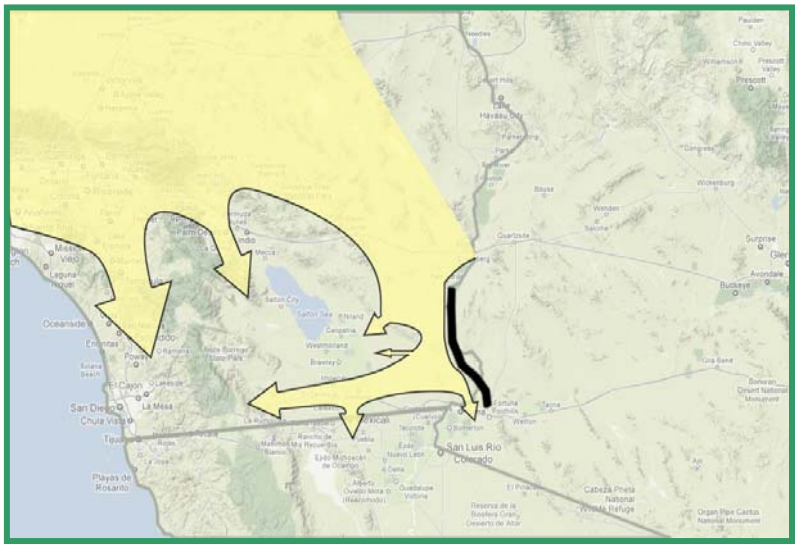

[41] *See* footnote 21. CFE stated that the trip was triggered by transients.

[42] The Modeling and Simulation team conducted a "what if" simulation and determined that, even without the inadvertent tripping of 160 MW of generation at La Rosita, the overloads and ensuing blackout would still have occurred.

**15:27:39 – The Hassayampa- North Gila 500 kV line tripped.**




**15:27:40**



## C. Phase 3: Trip of the Coachella Valley 230/92 kV Transformer and Voltage Depression

### Phase 3 Summary:

- Timing: 15:28:16, when CV transformer bank No. 2 tripped, to just before 15:32:10, when Ramon transformer tripped
- Both CV transformers tripped within 40 seconds of H-NG tripping
- IID knew losing both CV transformers would overload Ramon transformer and S Line connecting it with SDG&E
- Severe low voltage in WALC's 161 kV system
- At end of Phase 3, loading on Path 44 at 6,700 amps out of 8,000 needed to initiate SONGS separation scheme

At 15:28:16, less than a minute after H-NG tripped, IID's CV transformer bank No. 2 tripped on the 230 kV side. The CV overload protection relays detected an overload immediately after H-NG was lost. The overloads were caused by through-flows on IID's 92 and 161 kV systems which parallel APS's 500 kV system. The normal ratings for these transformers are 150 MVA, but immediately after H-NG tripped, each CV transformer was carrying more than 191 MVA. The relays were set to trip at approximately 127%[43] of the transformers' normal ratings, or 191.2 MVA at nominal voltage. The inverse time relays took 37.5 seconds to trip bank No. 2 and 38.2 seconds to trip bank No. 1. Thus, CV bank No. 1 tripped only 677 milliseconds after bank No. 2, again on the 230 kV side. Although the primary winding or high side voltages of the CV transformers are 230 kV, the banks were not considered as elements of the BES because their secondary winding or low side voltages are below 100 kV. As discussed in detail in Section IV, because these transformers and the underlying 92 kV system were not classified as elements of the BES, IID, neighboring TOPs, and WECC RC did not assess the impact of critical external contingencies on overloading the CV banks, the effect of losing the CV banks and the subsequent impact on the Ramon bank, and, finally their overall adverse effect on BPS reliability.

IID was aware of the potential for local cascading if the CV transformers tripped. IID's next-day plan for September 8, 2011, which was not based on updated studies, indicated that if both CV transformers tripped,[44] the Ramon 230/92 kV transformer would trip and the S Line tie with SDG&E would overload to 109% of its normal rating. The next-day plan also indicated that this overloading, in turn, would result in tripping

[43] IID's transformer protection philosophy specifies trip settings at 120% of normal ratings. IID chose the closest available relay tap, which was approximately 127% of the normal rating.

[44] This contingency scenario had nothing to do with H-NG tripping. IID's studies did not show any effect on the CV banks resulting from the loss of H-NG.

generation because the S Line RAS trips generation supplied to Imperial Valley when the S Line loads to 108% of its normal rating. IID's next-day mitigation plan for loss of the CV transformers required starting turbines at Coachella and Niland and asking CAISO to redispatch generation to relieve the S Line. This was a post-contingency mitigation plan. But after the event, IID's operator admitted that if the CV transformers tripped on overload, he would have "very little time to mitigate the Ramon [transformer], if at all." Even the quickest-starting turbines take about 10 minutes to start and ramp to full load, but IID effectively had only four minutes before the Ramon transformer would trip, after the loss of the CV transformers.

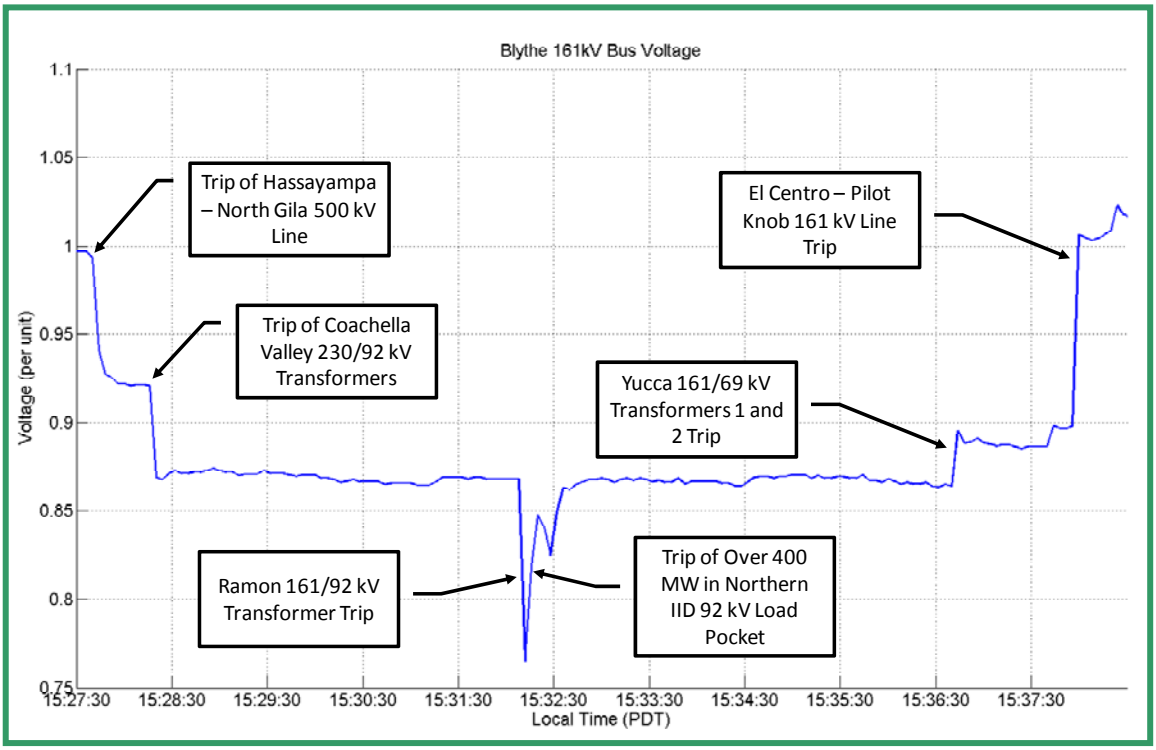
The loss of the CV banks caused flows on the S Line between SDG&E and IID to again reverse direction. Because its load exceeded internal generation, IID began pulling power from SCE through SDG&E due to the loss of key facilities in IID's northern system. The tripping of the second CV bank also open-ended the Coachella Valley-Ramon 230 kV "KS" Line (at CV), which was carrying about 41 MVA. This further increased loading on the Mirage-Ramon 230 kV line and through-flow from IID's 230 kV collector system through Devers, but had little effect on the overall disturbance. By 15:31:35, IID's operators switched in 92 kV capacitor banks at Avenue 42, Avenue 58, and Highline due to low voltage.

The loss of IID's two CV transformers caused the aggregate current on Path 44 to increase from 6,200 amps to 6,600 of the 8,000 amps necessary to trigger the SONGS separation scheme. However, by the end of this Phase aggregate Path 44 current reached 6,700 amps.

The loss of the CV banks caused a severe voltage depression on the WALC 161 kV system south of Blythe. During this period, loads in that area (largely irrigation pumps) were highly susceptible to motor stalling, which can create additional reactive demand and exacerbate transmission loading, both of which contribute to additional voltage decline. See ***Figure 8***, on the next page. At 15:28:18, the Blythe 161 kV bus alarmed at 142 kV (0.882 per unit).[45] WALC continued to experience severe low voltage on its 161 kV system until the S Line tripped at 15:38:02.4.

[45] Other alarms and low voltage readings followed throughout WALC's system one to nine seconds later, including the Parker-Kofa 161 kV line, which alarmed for overload at 169 MVA (167 MVA rating); Kofa 161 kV bus voltage recorded at 143 kV (0.888 per unit); Knob 161 kV bus voltage recorded at 142 kV (0.882 per unit); Parker 161 kV bus voltage recorded at 149 kV (0.925 per unit); Gila and Goldmine 161 kV bus voltages recorded at 144 kV (0.894 per unit); and Parker 230 kV bus voltage recorded at 222 (0.965 per unit).

**Figure 8: Blythe 161kV Voltage**

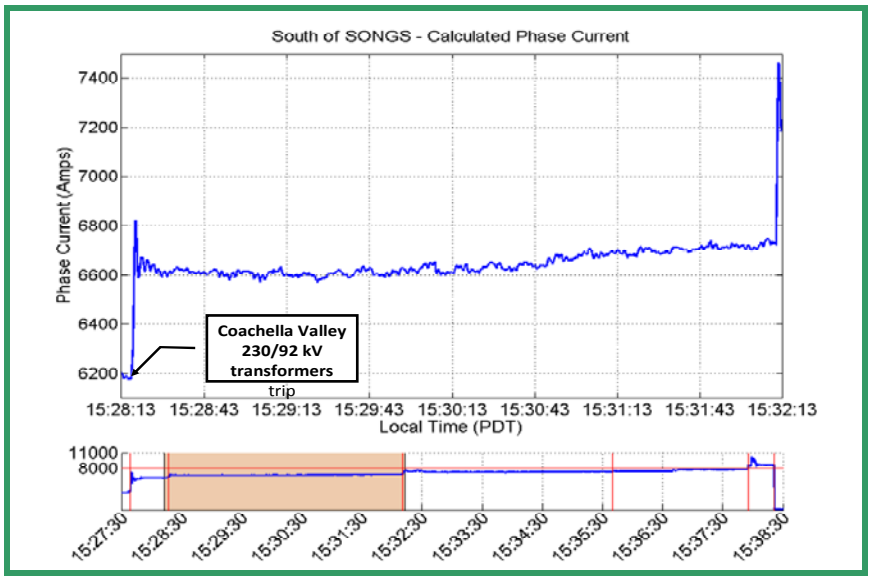



On September 8, 2011, CAISO had partial visibility of IID's system, but could not see that the CV banks had tripped. Prior to the event CAISO and IID had been working together to increase their mutual visibility and those efforts are continuing. Currently, CAISO receives loading data from the 230 kV side of the CV transformers.

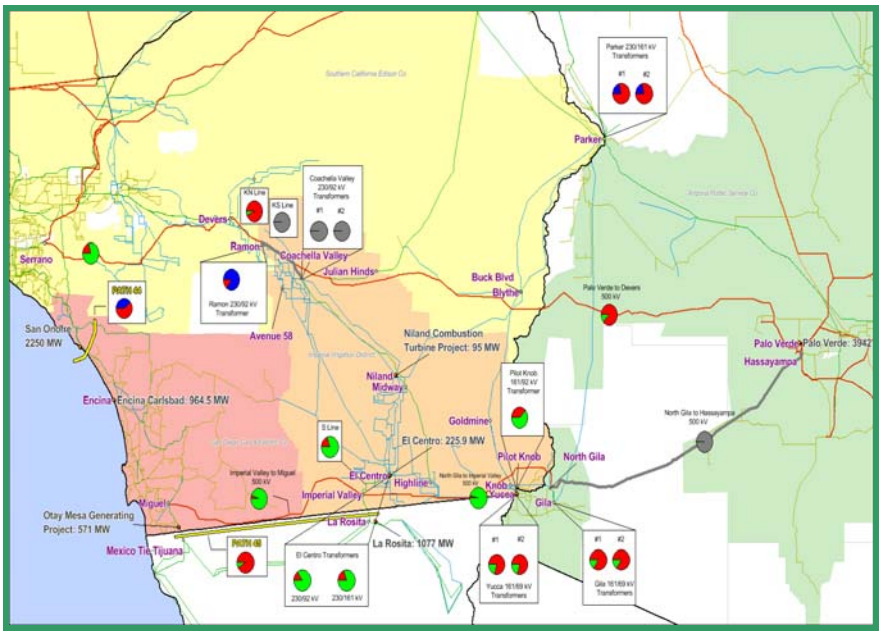
Despite the fact that it did not consider the CV banks to be part of the BES, WECC RC does observe much of IID's 92 kV system in real time, including the CV banks. The WECC RC operator did notice the CV transformers trip, but he was focused on when APS would return H-NG to service.

## Phase 3 Graphics

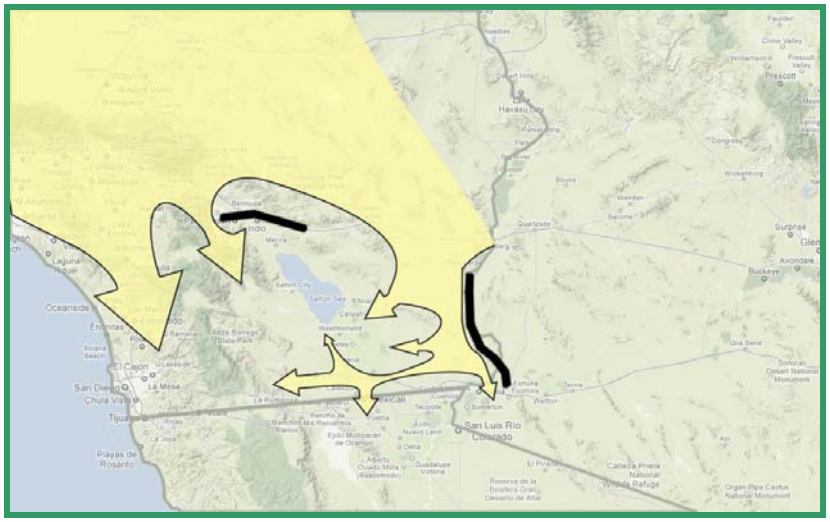
### South of SONGS – Calculated Phase Current




### 15:28:17 – Two Coachella Valley 230/92 kV transformers and the Coachella Valley Ramon 230 kV "KS" line tripped. (030)



**15:28:18**




## D. Phase 4: Trip of Ramon 230/92 kV Transformer and Collapse of IID's Northern 92 kV System

### Phase 4 Summary:

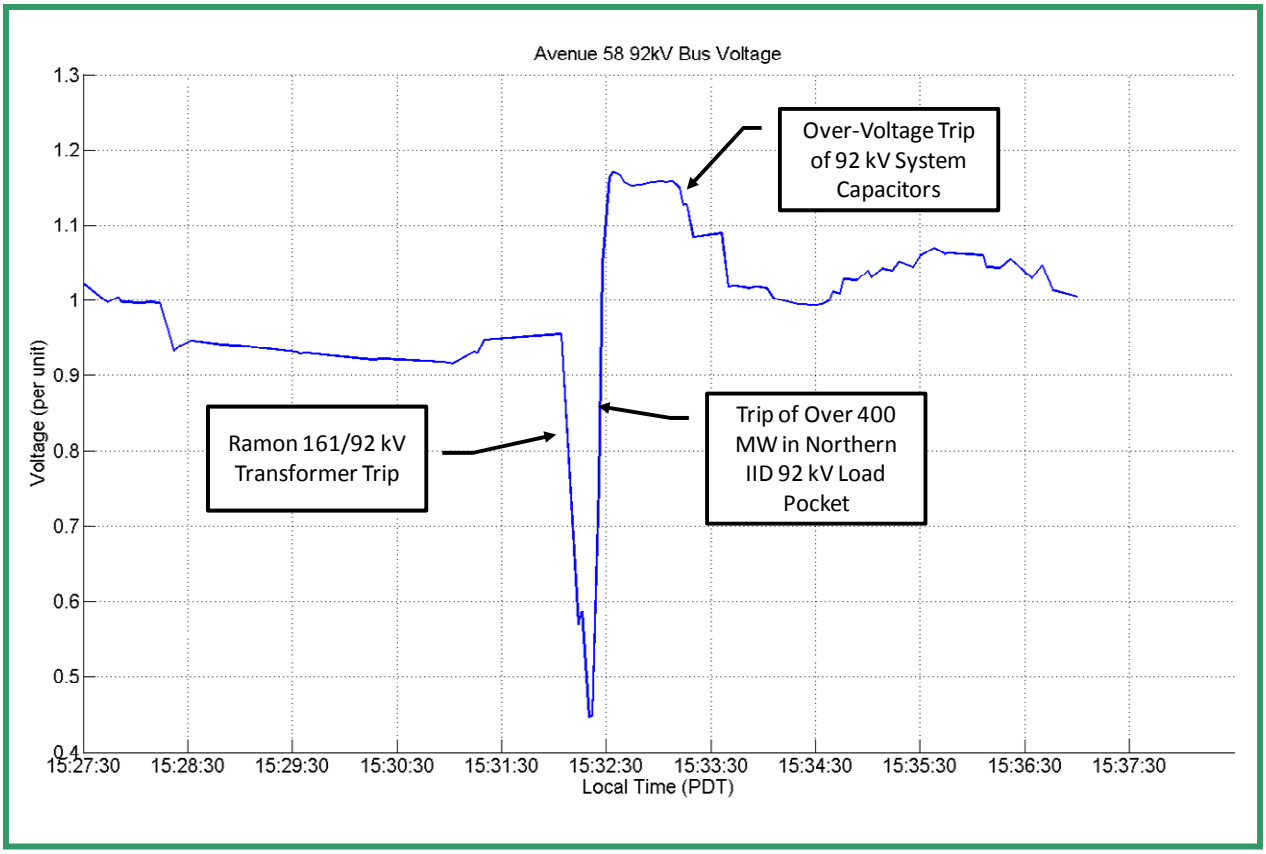
- Timing: 15:32:10 to just before 15:35:40
- IID's Ramon 230/92 transformer tripped at 15:32:10, was set for 207% of its normal rating instead of its design setting of 120%, which allowed it to last approximately four minutes longer than CV transformers
- IID experienced undervoltage load shedding, generation and transmission line loss in its 92 kV system
- Path 44 loading increased from approximately 6,700 amps, to as high as 7,800 amps, and ended at around 7,200 amps (out of 8,000 needed to initiate the SONGS separation scheme)

At 15:32:10.621, less than five minutes after the trip of H-NG, IID's Ramon 230/92 kV transformer tripped on the 92 kV side. The normal rating for this transformer was 225 MVA, and its relays were set to trip above 207% of its normal rating, or 466 MVA. Before it tripped, the SCADA metering for the Ramon bank had stopped recording accurate readings due to RTUs exceeding maximum scale, just as for the CV banks. Following the loss of the CV transformers, the inverse time relays took less than four minutes to trip the Ramon transformer. IID had intended to set the Ramon transformer to trip at 120% of its normal rating. Had it been set at this level, the Ramon transformer would have tripped almost immediately after the loss of the CV transformers, approximately four minutes earlier than the time of its actual trip. IID believed that the Ramon transformer would overload beyond the trip point upon the loss of both CV transformers. Its next-day plan noted, "the Ramon Bank #1 transformer will overload and relay out of service because the overcurrent settings are set to trip at

120%." IID's next-day plan relied on a post-contingency operating philosophy of starting the Coachella Gas Turbines to mitigate overloads following the loss of the CV transformers, but the plan was unrealistic as IID would not have had time to start any additional generation between the loss of the CV transformer banks and the loss of the Ramon transformer.

Within less than one second after the loss of the Ramon transformer, automatic distribution undervoltage protection in IID's northern 92 kV system began tripping distribution feeders and shedding load. From 15:32:11 to 15:33:46, 444 MW of IID's load tripped, with nearly half of the load being shed within 10 seconds of the Ramon transformer tripping. As illustrated in ***Figure* 9**, below, the severe voltage depression following the loss of the Ramon transformer appears to have prompted a local voltage collapse within IID's northern 92 kV system, evidenced by both the steep drop-off in voltage as well as a sharp rise in reactive power flow due to motor stalling.

**Figure 9: 92kV Voltage (per unit) at Avenue 58**



The loss of IID's northern resources and subsequent system response caused IID to lose multiple generators connected to its 92 kV system, including IID's Niland Gas Turbine 2 (generating 45 MW), IID's CV Gas Turbine 4 (generating 20 MW), independent power producer Colmac's unit (generating 46 MW), and IID's Drop 4 Unit 2 Hydro Generator (generating 10.3 MW).

IID also began losing transmission lines. The Blythe-Niland 161 kV "F" Line, which saw increased loading during Phase 2, tripped at 15:32:13 (approximately 3 seconds after loss of the Ramon banks). Its normal rating was 165 MVA, and it was set to trip at 129% of the normal rating (212 MVA at nominal voltage) with a 3-second time delay.[46] The Niland-CV 161 kV "N" Line, carrying 83 MVA, tripped approximately 2 seconds later at 15:32:15.29 due to Zone 3 distance protection.[47]

In WALC's territory, the Blythe-Goldmine-Knob and Parker-Kofa 161 kV lines overloaded approximately four seconds after the Ramon transformer tripped, at 15:32:14, but did not trip. These lines each had a normal rating of 167 MVA, but were loaded to 177 MVA. Power flows redistributed through the Parker and Blythe areas after IID lost the Blythe-Niland line. WALC took some actions in an attempt to arrest the voltage depression it was experiencing, including a directive to start hydropower generation units Parker 3 and 4 for voltage support at 15:34:07. At the time, Parker area voltage was at 150 kV (0.932 per unit). WALC also switched in shunt capacitors on the 69 kV system at Gila and Kofa. At the time, voltage at Gila was at 65.5 kV (0.906 per unit) while Kofa was at 59 kV (0.86 per unit).

CAISO attempted to bring on generation through its exceptional dispatch[48] process to bring Path 44 back within its limit of 2,500 MW, anticipating that it had 30 minutes to do so. At 15:35, it dispatched the Larkspur No. 2 peaking unit (rated 50 MW) within San Diego, which has a 20-minute start-up time. Also at this time, APS began taking steps to restore H-NG by completing the bypass of the series capacitor bank.

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[46] Based on the last available SCADA scan before the line tripped, the voltage at Blythe was at 123.1 kV (0.765 per unit) and the line was loaded to 172 MVA. Based on these measurements, the line was carrying 807 amps at the last time recorded; the relay was set to trip with a 3-second time delay at 762 amps.

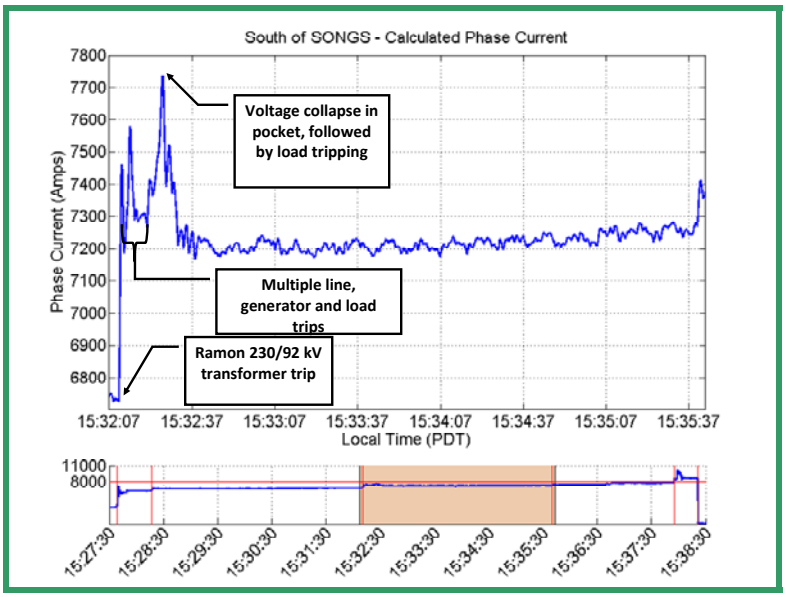
[47] A distance relay is a relay that compares observed voltage and current on a line and operates when that ratio is below its preset value. Zone 3 relays are typically set to protect against faults that are more than one substation away from the observed line as backup protection. An appropriate time delay should be set in the relay to give the remote station relays the opportunity to operate and isolate the minimum amount of equipment necessary to clear the fault. A common issue with the application of Zone 3 relays is that they can restrict the loading on transmission lines (e.g. the N Line) during abnormal system conditions like those present on September 8th.

[48] CAISO's exceptional dispatch process involves calling on generators outside of the market automated dispatch process.

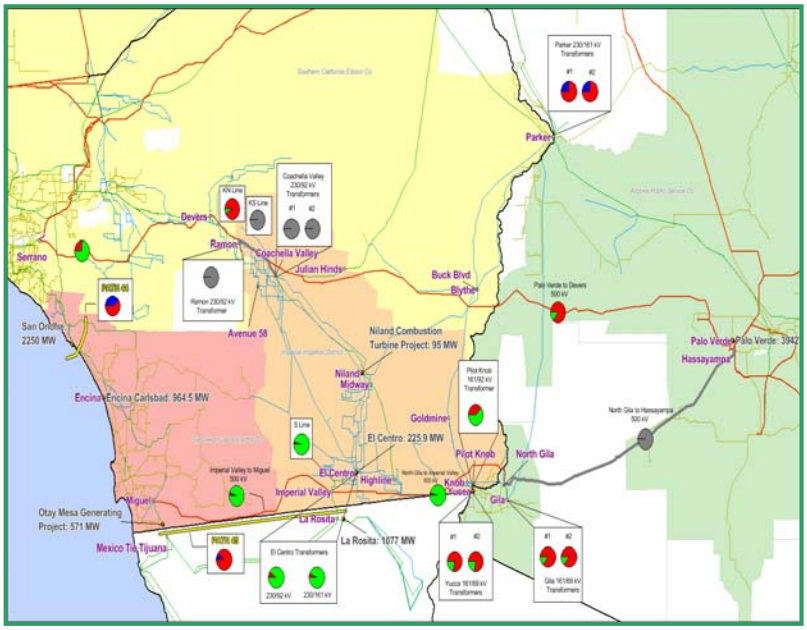
During Phase 4, aggregate loading on the South of SONGS 230 kV transmission lines increased from approximately 6,700 amps to as high as 7,800 amps. The loading settled around 7,200 amps and remained there for the rest of Phase 4.

## Phase 4 Graphics

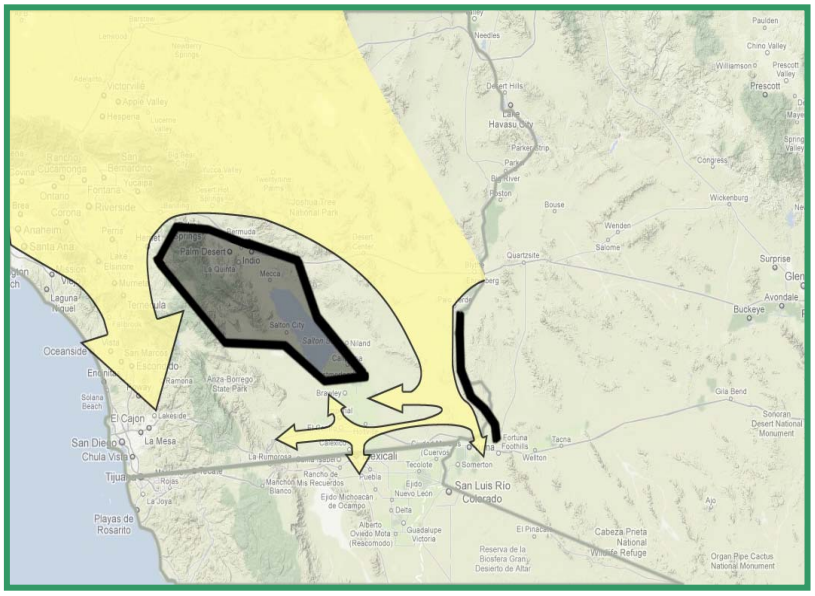
**South of SONGS – Calculated Phase Current**




**Time: 15:32:10 – The Ramon 230/92 kV transformer tripped and IID shed 444 MW of load. (110)**



**Time: 15:32:35**




## E. Phase 5: Yuma Load Pocket Separates from IID and WALC

### Phase 5 Summary:

- Timing: 15:35:40 to just before 15:37:55
- The Gila and Yucca transformers tripped, isolating the Yuma load pocket to a single tie with SDG&E
- Path 44 loading increased from 7,200 to 7,400 amps after Gila transformer tripped, and ended at 7,800 amps after loss of the Yucca transformers and YCA generator (very close to the 8,000 amps needed to initiate the SONGS separation scheme)

At 15:35:40, approximately eight minutes after H-NG tripped, WALC's Gila 161/69 kV transformers tripped due to time-overcurrent protection. The two transformers are each rated 75 MVA, but the 69 kV bus section that connects the transformers to the rest of the 69 kV substation is rated 1,200 amps (143 MVA at nominal voltage), and the overcurrent protection is set accordingly at 1,200 amps. The bus was carrying 1,312 amps at the time of the trip.

One minute later, at 15:36:40, the Yucca 161/69 kV transformers 1 and 2 tripped when their common 69 kV breaker tripped due to overload protection. Bank No. 1 is owned by IID and is rated 73 MVA, and bank No. 2 is owned by APS and is rated 75 MVA. The IID Yucca generator and four out of the six APS combustion turbines connected to APS's 69 kV system were offline at the time of the event, as was the IID GT21 combustion turbine on the 161 KV side. These generators may have supported load in the area had they been in service. Almost immediately, the Pilot Knob breaker on the Pilot Knob-Yucca 161 kV "AX" transmission line, which is effectively the 161 kV breaker

for the Yucca 161/69 kV transformers, received a direct transfer trip from the Yucca transformer overload protection, thereby tripping the AX Line. As a result of the loss of the Yucca and Gila transformers, the Yuma load pocket was isolated to only one tie to the SDG&E system, causing loading on each N. Gila 500/69 kV transformer bank to increase from 57 MVA to 164 MVA.

Less than one second after the Yucca transformers and AX Line tripped, at 15:35:40, the Yuma Cogeneration Associates (YCA) combined cycle plant on the Yuma 69 kV system tripped. The combustion turbine is rated at 35 MW and the heat recovery unit is rated at 17 MW, totaling 52 MW. It appears that both units were fully loaded at the time of the trip. The cause of the trip is unknown, but the loss of the YCA unit hastened the collapse of the Yuma load pocket.

Approximately one minute later, at 15:37:41, a common 161 kV breaker tripped IID's Pilot Knob 161/92 kV transformers Nos. 2 and 5 for No. 2 overload protection. The overload protection was set to trip the banks at 121% of the normal rating (37.5 MVA at nominal voltage).

At WALC's request, between 15:36:48 and 15:36:52, SCE directed Metropolitan Water District operators to drop 80 MW of pumping load attached to the Gene substation (near Parker) to improve 230 kV voltage support at Parker in an attempt to arrest declining voltages.

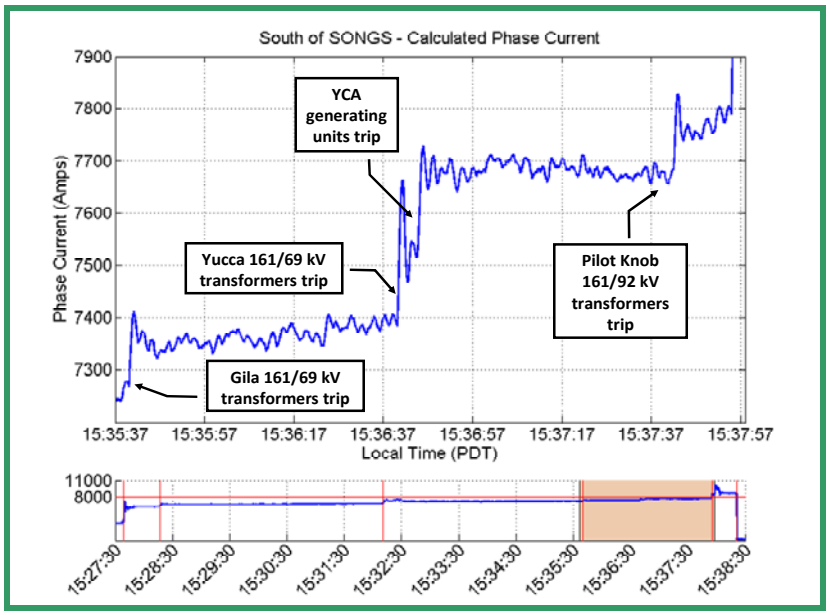
As it had done during Phase 4, CAISO ordered exceptional dispatch to bring Path 44 below its 2,500 MW limit. At 15:36:00, CAISO called SCE and ordered an exceptional dispatch of Larkspur Peaking Unit No. 1 (rated 50 MW), and Kearny GT2 and GT3 (each rated 59 MW) to go to full load. The Larkspur unit takes 20 minutes to start, and the Kearny units are 10-minute "quick start" peaking generators. All of these units were offline at the time, and they were unable to come online before the system collapsed.[49]

The tripping of the Gila 161/69 kV transformers caused the aggregate loading on Path 44 to increase from approximately 7,200 amps to approximately 7,400 amps, out of the 8,000 amps necessary to initiate the SONGS separation scheme. After the loss of the Yucca 161/69 kV transformers, the YCA plant, and the Pilot Knob 161/92 kV transformers, the loading further increased to approximately 7,800 amps.

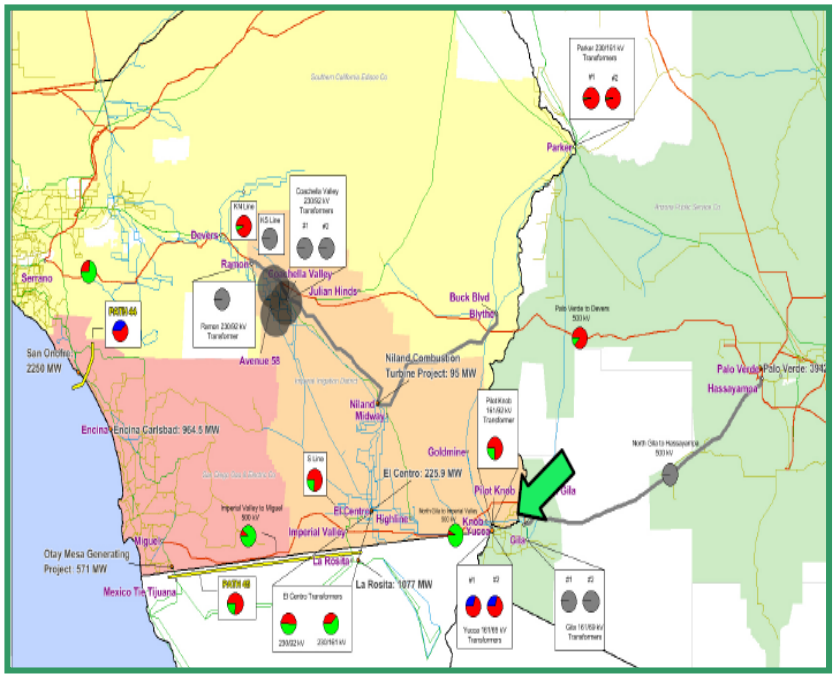
[49] Larkspur generation is connected to the SDG&E 69 kV system south of Otay Mesa, and Kearny generation is connected to the SDG&E 69 kV system in northern San Diego.

## Phase 5 Graphics

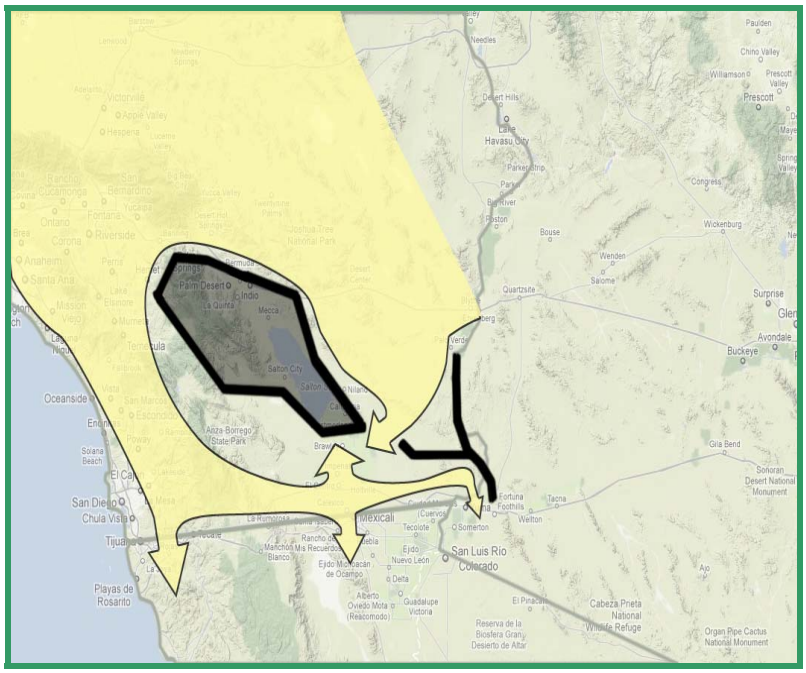
### South of SONGS – Calculated Phase Current




### Time: 15:35:31 – Yuma Cogen (YCA) tripped. (180)



**Time: 15:37:42**




## F. Phase 6: High-Speed Cascade, Operation of the SONGS Separation Scheme and Islanding of San Diego, IID, CFE, and Yuma

### Phase 6 summary:

- Timing: 15:37:55 to 15:38:21.2
- IID's El Centro-Pilot Knob line tripped, forcing all of IID's southern 92 kV system to draw from SDG&E via the S Line
- S Line RAS operates, tripping generation at Imperial Valley and worsening the loading on Path 44
- S Line RAS trips S Line, isolating IID from SDG&E
- Path 44 exceeds trip point of 8,000 amps, to as high as 9,500 amps
- SONGS separation scheme operates and creates SDG&E/CFE/Yuma island

When the El Centro-Pilot Knob 161 kV line tripped at 15:37:55 (10 minutes after loss of H-NG), it isolated the southern IID 92 kV system onto a single transmission line from SDG&E: the S Line. Forcing all of the remaining load in IID to draw through the SDG&E system pushed the aggregate current on Path 44 to 8,400 amps, well above the trip point of 8,000 amps. If the aggregate current on Path 44 remained above 8,000

amps, the definite minimum time relay[50] would initiate the SONGS separation scheme to separate SDG&E from SCE at SONGS.

IID's El Centro-Pilot Knob 161 kV line open-ended at El Centro when a 161 kV breaker at El Centro tripped on Zone 3 relay protection[51] with a one second delay. The apparent impedance detected on the Zone 3 relay at El Centro was hovering near its trip zone immediately following the Pilot Knob 161/92 kV transformer trips (12 seconds earlier), but did not cross into the Zone 3 tripping region until this time.

By this time in the event, the South of SONGS lines were San Diego's only source of critical imported generation, and were also keeping IID and CFE's Baja California Control Area from going dark. If the aggregate current was brought below 8,000 amps, the blackout could have been avoided, but at this point no operator action could have occurred quickly enough to save the South of SONGS Path. Had there been formal operating procedures that recognized the need to promptly shed load as the aggregate current approached 8,000, and had operators been trained on the 8,000 amp set point, it is possible that operation of the SONGS separation scheme could have been averted by earlier control actions.

Milliseconds after the loss of IID's El Centro-Pilot Knob 161 kV line, at 15:37:55.890, NextEra's Buck Boulevard combustion turbine generator tripped due to operation of SCE's Blythe Energy RAS, dropping 128 MW of generation.[52] This was caused by a reduction of counter-flows on the Julian Hinds-Mirage 230 kV line that had been created by heavy flows from the Julian Hinds-Eagle Mountain 230 kV line feeding toward the WALC 161 kV system to support the heavy north to south 161 kV flows toward Pilot Knob. When the El Centro-Pilot Knob 161 kV line tripped, those counter-flows disappeared, initiating the RAS operation. The Buck Boulevard heat recovery unit ramped down by 82 MW over the next few minutes. The Buck Boulevard combined cycle plant was generating 409 MW (535 MW rating) at the time the combustion turbine tripped. Tripping the Buck Boulevard generator did not increase loading on Path 44, because it is not located south of Path 44.

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[50] A definite minimum time relay can operate in one of two ways. When current reaches a certain value, the relay will operate with a *definite* time delay that reflects the relay's fastest operating time. Before the relay reaches that value, the time for the relay to operate is *inversely proportional to its observed current magnitude*. During the event, the relay operated while following the latter characteristic.

[51] *See* footnote 47, *supra*.

[52] The Blythe Energy RAS, among other functions, trips generation owned by NextEra to protect the Julian Hinds-Mirage 230 kV line from overloading with east to west flows for a potential loss of the Julian Hinds-Eagle Mountain 230 kV line. Buck Boulevard is connected to SCE's 230 kV system in the Blythe area.

Just three seconds after the loss of IID's El Centro-Pilot Knob 161 kV line, at 15:37.58.2, the S Line RAS at Imperial Valley Substation initiated the tripping of two combined cycle generators at Central La Rosita in Mexico. The S Line RAS currently protects El Centro's 161/92 kV transformer No. 2 by initially tripping a combination of CLR II generators when the flow on the S Line exceeds 269 MW flowing northward from SDG&E into IID. Two combustion turbines were loaded to 152 MW (193.5 MW rating), and 153 MW (193.5 MW rating), respectively, and the associated steam heat recovery unit (which also tripped following loss of the turbines) was loaded to 127 MW (159.3 rating), totaling 432 MW of generation.

Loss of the CLR II generation drove the South of SONGS flows from about 8,400 amps to about 9,500 amps, which remained above the 8,000 amp setting of the SONGS separation scheme. The inquiry's simulation showed that had the S Line tripped without the S Line RAS tripping the CLR II generation, the flow on Path 44 would have fallen below 8,000 amps to settle at an estimated 7,730 amps, and the SONGS separation scheme might not have operated.[53]

Approximately four seconds after the S Line RAS tripped the CLR II generators, at 15:38:02.4 the S Line RAS tripped the S Line itself due to flow above 289 MW toward IID from SDG&E. Tripping of this line created an IID island. IID reported that from 15:37:59 to 15:40:24, 507.85 MW of load tripped on its system, mostly in the southern 92 kV system.

The tripping of the S Line meant that IID was no longer pulling power from SDG&E and CFE through Path 44, so the aggregate Path 44 flows decreased from approximately 9,500 amps to approximately 8,700 amps, but were still above the 8,000 amps required to trigger the SONGS separation scheme.

At 15:38:21.2, not quite 11 minutes after H-NG tripped, the SONGS separation scheme operated, reconfiguring the SONGS 230 kV switchyard and isolating the SONGS generators onto the SCE system to the north. This reconfiguration effectively separated

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[53] The inquiry's simulation showed that if the S Line RAS tripped only the S Line, IID's system would still have collapsed, but San Diego and the Yuma load pocket would likely have survived. Voltages would have remained acceptable, and the 230 kV system around SONGS may have experienced minor overloads. While this would have resulted in a large phase angle difference on H-NG, the fact that the SONGS separation scheme would not have operated would have allowed time for system operators to make the load and generation changes necessary to reduce the phase angle difference.

Had the S Line RAS not operated at all, or only operated to trip the CLR II generators, Path 44 flows would have settled above the 8,000 amp threshold and thus the SONGS separation scheme would still have operated.

all five South of SONGS 230 kV transmission lines from the SONGS units and the SCE system, and separated SDG&E from the rest of the Western Interconnection. Operation of the SONGS separation scheme created an island consisting of the SDG&E system, the remaining Yuma-area load connected through the 500 kV system from Miguel to North Gila, and CFE's Baja California Control Area.

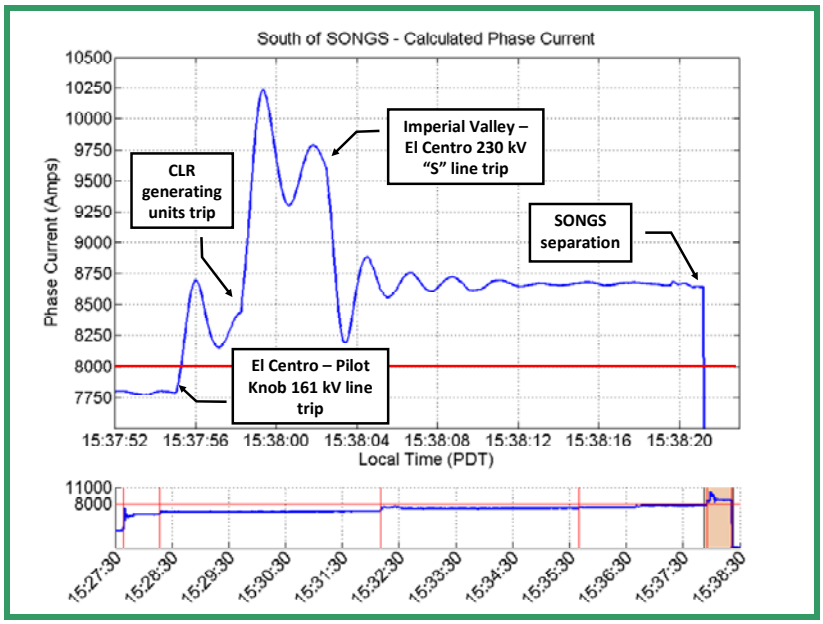
September 8, 2011, was the first time that the SONGS separation scheme had ever activated, and its effects on neighboring systems had not been studied. Although this sequence of events has focused on how the loss of elements combined over the 11 minutes to exceed the 8,000 amp SONGS separation scheme trigger, in real time, no entity was monitoring that limit or recognized the potential consequences of its operation.

WECC RC, responsible for the reliable operation of the BPS, and with having a wide area view of the BPS, did not have any alarm that would alert operators before operation of the separation scheme. Although WECC RC operators were monitoring the Path limit on Path 44, they were not watching the aggregate flows with respect to the SONGS separation scheme trigger. WECC RC operators noticed the five South of SONGS breakers open after the scheme had already operated.

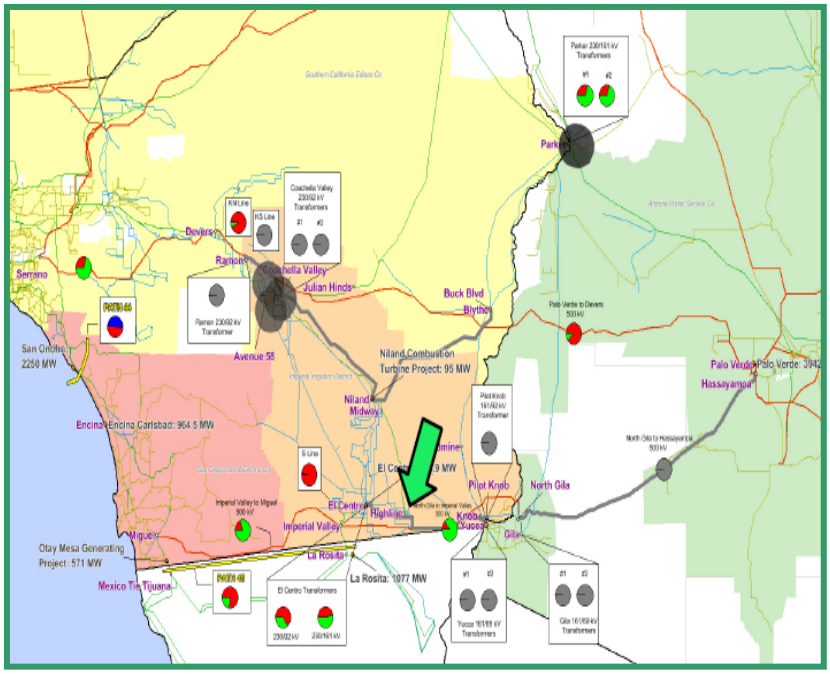
CAISO, the TOP for SDG&E and SCE, did not have any alarms specifically tied to the operation of the SONGS separation scheme either. CAISO only has alarms for when Path 44 exceeds its Path rating, but had no ability to monitor the SONGS separation scheme, set at 3,100 MW (8,000 amps). After the loss of H-NG, which caused Path 44 to exceed its Path rating, CAISO operators were primarily concerned with returning flows on Path 44 to below the Path rating of 2,500 MW, but believed they had 30 minutes to do so. Unlike Path ratings, the separation scheme would not allow CAISO operators 30 minutes to reduce flows on Path 44. CAISO did attempt to dispatch additional generation within SDG&E to reduce flows on Path 44. The other method to reduce flows would have been to manually shed load in SDG&E in time to prevent operation of the SONGS separation scheme. SDG&E estimates that it could have shed approximately 240 MW in between two and two-and-a-half minutes. However, SDG&E was never instructed to shed load and was unaware of the need to shed load.

## Phase 6 Graphics

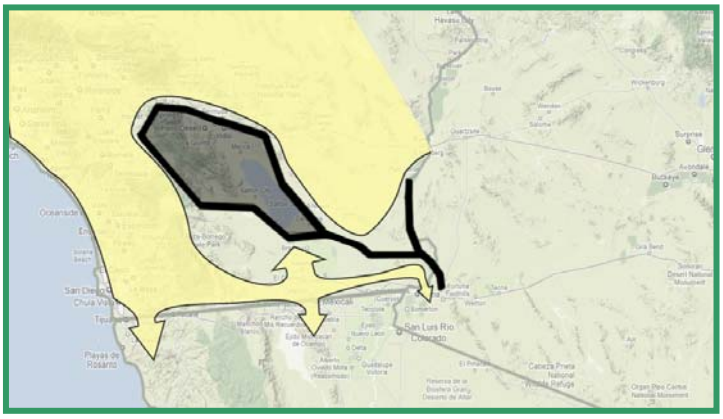
### South of SONGS – Calculated Phase Current




### Time: 15:37:55 – The El Centro-Pilot Knob 161 kV line tripped. (230)



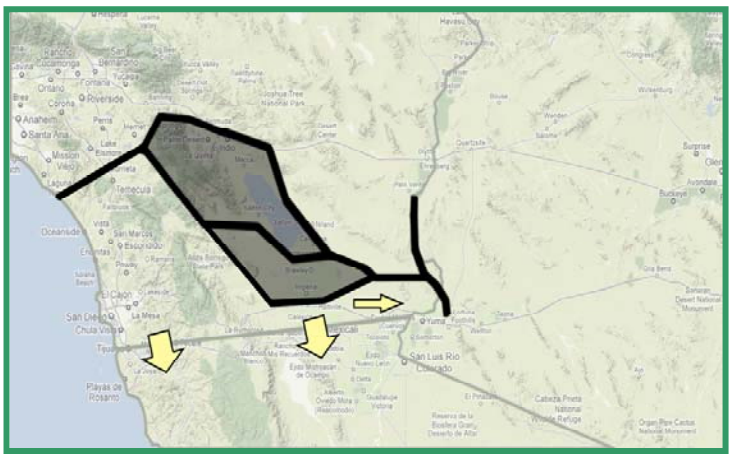
**Time: 15:37:55.110**



**Time: 15:38:02.4**



**Time: 15:38:21.2**



## G. Phase 7: Collapse of the San Diego/CFE/Yuma Island

### Phase 7 Summary:

- Timing: Just after 15:38:21.2 to 15:38:38
- Underfrequency Load Shedding (UFLS) was not able to prevent the SDG&E/CFE/Yuma island from collapsing
- SONGS nuclear units shut down even though they remained connected to the SCE side of the SONGS separation scheme

During phase 7 of the event the SDG&E/CFE/Yuma island broke into three separate islands, all of which collapsed due to an imbalance between generation and demand, resulting in severe underfrequency which tripped both loads and generation.

The SDG&E/CFE/Yuma island created by operation of the SONGS separation scheme had a significant imbalance between generation and load from the beginning. As a result, the frequency in the island rapidly declined. By less than a second after the SONGS separation scheme activated (15:38:22), the UFLS programs of SDG&E, APS, and CFE had all began activating within the island. *Figures* 10 and 11, below show the frequency within the island as it collapses. All steps of the UFLS systems activated and system frequency in the island briefly stalled at approximately 57.2 hertz (Hz). CFE's UFLS analysis showed 512 MW of load shed by 15:38:21.901.

However, the same analysis showed that three CFE generators, totaling 459 MW, tripped offline beginning at 15:38:21.905, partially negating CFE's UFLS actions. In addition, a number of smaller generators, totaling about 130 MW, tripped only 0.5 seconds later while CFE was still connected to SDG&E and while SDG&E's UFLS program was still working to shed load.[54] See *Figure* 11, below. The net effect of CFE's UFLS actions and generator trips—512 MW shed by UFLS and 590 MW of tripped generation—was that CFE's imports from SDG&E increased from approximately 440 MW to approximately 520 MW. This worsened CFE's system conditions and increased the stress on SDG&E before SDG&E's underfrequency separation protection systems opened the ties between CFE and SDG&E. SDG&E also had three generators with underfrequency protection that operated at 57.3 Hz, above the frequency at which the system leveled out. Due to these early generation losses, the frequency continued to decline below 57 Hz, which was the underfrequency setting for the majority of generators in the island. Thus, the island blacked out, shortly after separating into three sub-islands.

[54] The fact that several generators tripped during load shedding suggests that CFE may benefit from analyzing whether its UFLS program and generator underfrequency protection systems are coordinated.

**Figure 10: Frequency, Voltage in the SDG&E/Yuma/CFE Island**

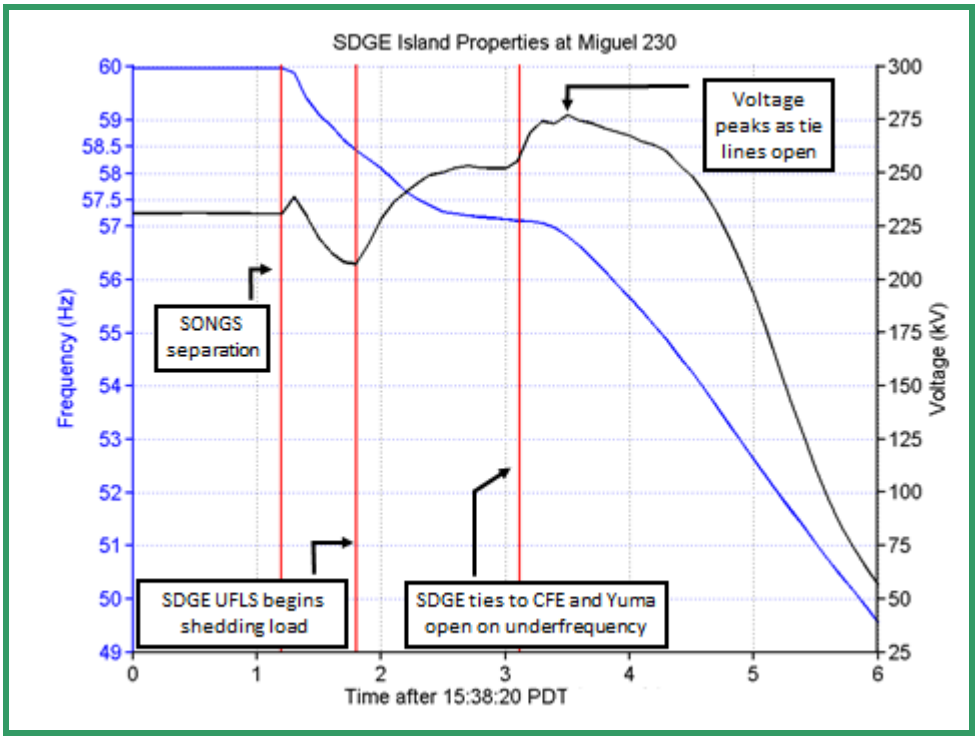
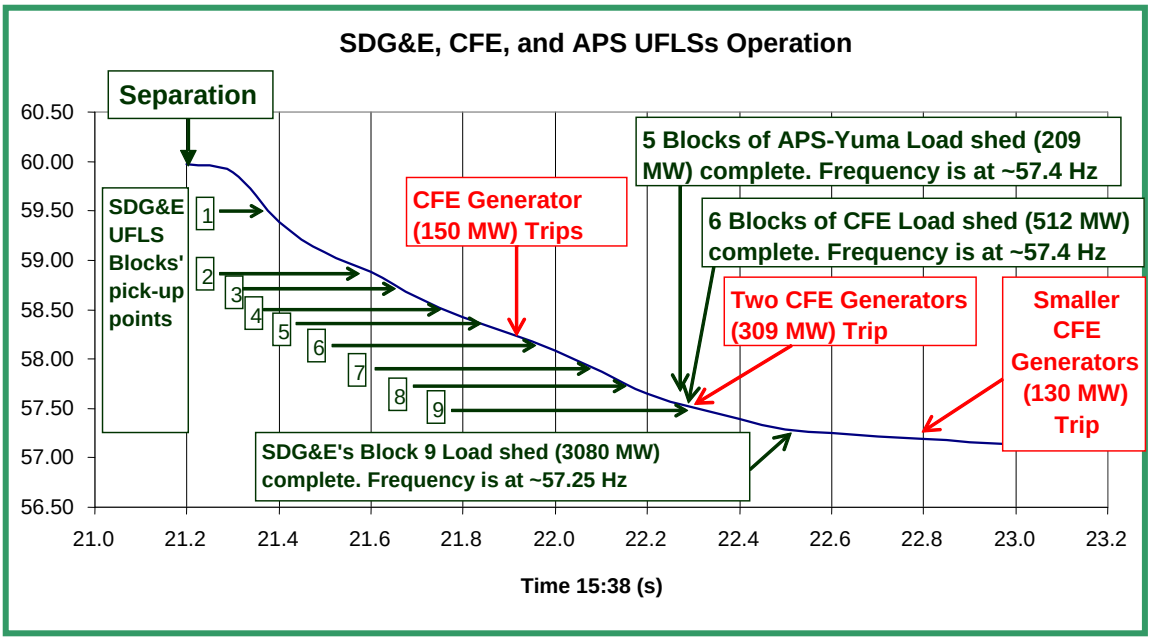



**Figure 11: Frequency Performance in the SDG&E/Yuma/CFE Island**



The CFE island separated from SDG&E after their only two remaining ties tripped in rapid succession. At 15:38:22.2, the Otay Mesa-Tijuana 230 kV transmission line open-ended at Tijuana in CFE's territory due to underfrequency protection.[55] Less than a second later, at 15:38:23.13, the Imperial Valley-La Rosita 230 kV transmission line open-ended at Imperial Valley in SDG&E's territory by underfrequency protection.[56] According to CFE, its UFLS program was not designed for the operation of a SDG&E/CFE/Yuma island, but for the operation of a "southern WECC island."

The Yuma island separated from SDG&E at 15:38:23.12, when the Imperial Valley-North Gila 500 kV transmission line tripped by underfrequency protection. APS's UFLS operated on 26 out of the 28 feeders in the Yuma area prior to the loss of the local Yucca steam generators that were on line. However, there was insufficient local generation to stabilize the load pocket in Yuma. At 15:38:38, the Yuma island internal units tripped on underfrequency protection.

At about the same time that it separated from CFE and APS's Yuma pocket, SDG&E lost four generating units, totaling 570 MW, due to the generators' underfrequency protection.[57]

Although the SONGS generators remained connected to the SCE side of the switchyard at SONGS, at about 15:38:27.5, or approximately six seconds after the SONGS separation scheme initiated, the SONGS turbines both experienced a brief acceleration in speed and tripped due to turbine control logic. At the same time, local system frequency at SONGS was observed to spike from 59.974 Hz to 61.203 Hz. After the initial impulse caused by the system separation, the frequency in the main body of the Western Interconnection peaked near 60.170 Hz. This can be seen on Figures 12 and 13, on the next page. The turbine trip initiated a reactor shutdown, and the units began coasting down. A little more than a second later, at 15:38:28.963, SONGS Unit 3 electrically disconnected from the system, and less than three seconds after the reactors

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[55] The Tijuana end opened instantaneously. Subsequently, the Otay Mesa end of the line in SDG&E's territory opened at 15:38:23.044 by underfrequency protection (with 1-second delay).

[56] The line's underfrequency setting was 57.9 Hz, with 1-second delay. The instantaneous underfrequency protection scheme at La Rosita in CFE's territory failed to operate due to a bad fuse connection.

[57] At 15:38:23.000, the Palomar Energy Center combustion turbines CT1 and CT2 tripped on underfrequency, followed by the heat recovery unit ST at 15:38:23.07 (all set to trip at 57.3 Hz with a 750 millisecond time delay). CT1 was loaded to 160 MW, CT2 was loaded to 165 MW, and ST was loaded to 195 MW at the time of the trips. It is believed that additional unit Goal Line LP, generating 50 MW, tripped around the same time due to a 58 Hz frequency with a 1-second time delay.

shut down, at 15:38:30.209, SONGS Unit 2 electrically disconnected from the system. Loss of the 2,300 MW of SONGS' generation effectively reduced the loss of load for the main body of the Western Interconnection from a 3,400 MW loss to a net 1,100 MW load loss. This made the recovery from the resulting overfrequency event much easier. The SONGS generators did not lose offsite power because the SONGS switchyard was still connected to the SCE system.

**Figure 12 : Frequency Excursion in WECC Interconnection Immediately after the SONGS**

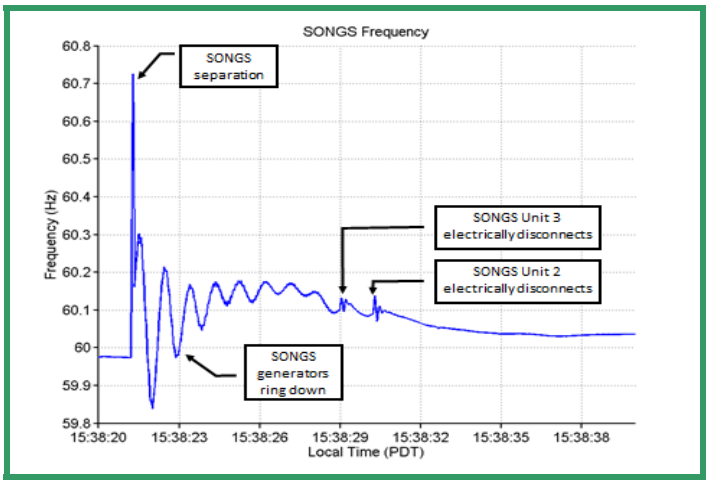
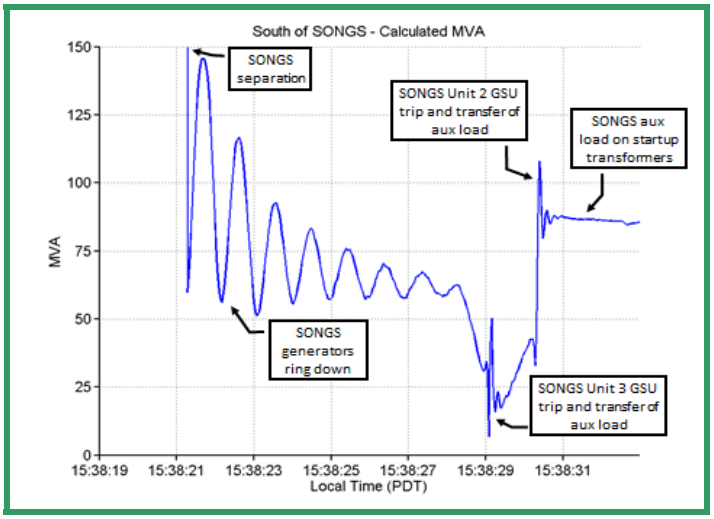


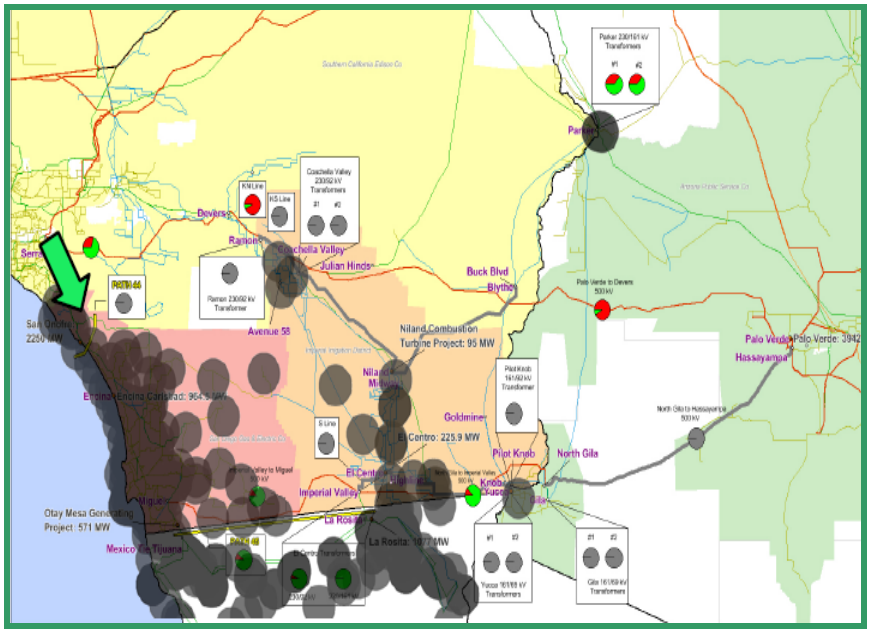

**Figure 13: SONGS Generation Trips and Auxiliary Loads Transfer to 230 kV Bus**



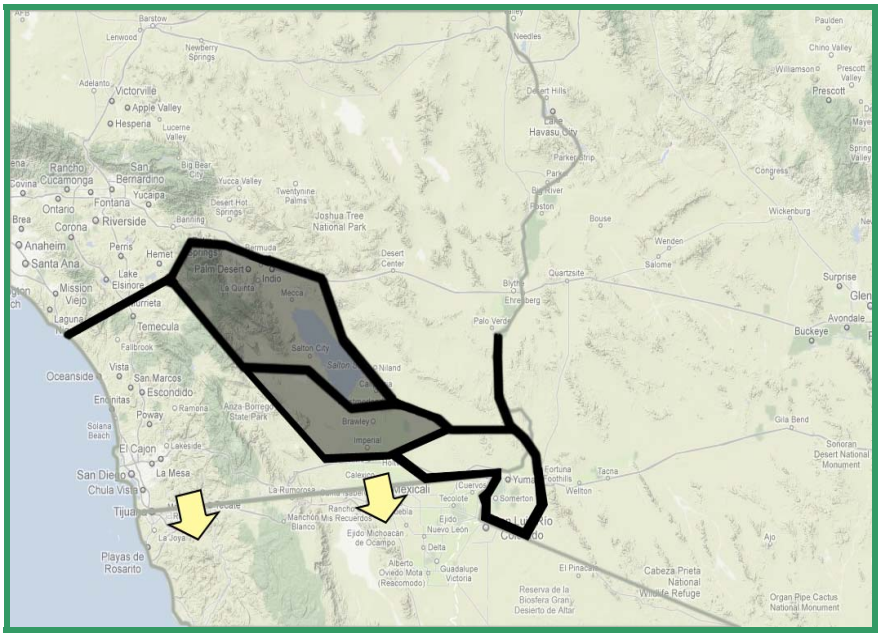
By 15:38:38, the SDG&E, CFE and Yuma islands had all collapsed, leaving approximately 2.7 million customers without power.

## Phase 7 Graphics

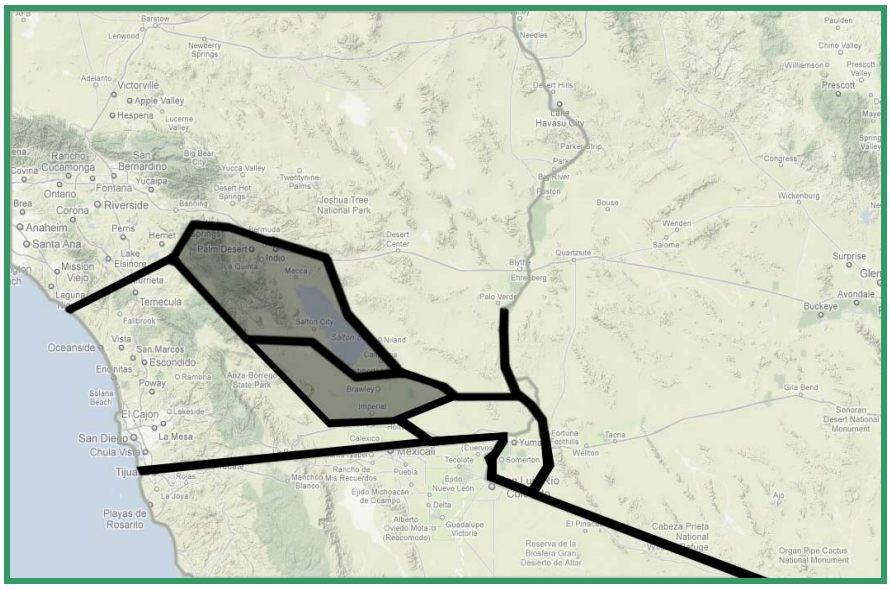
**Time: 15:38:30 – The South of SONGS Separation Scheme operates and both SONGS units tripped. (300)**



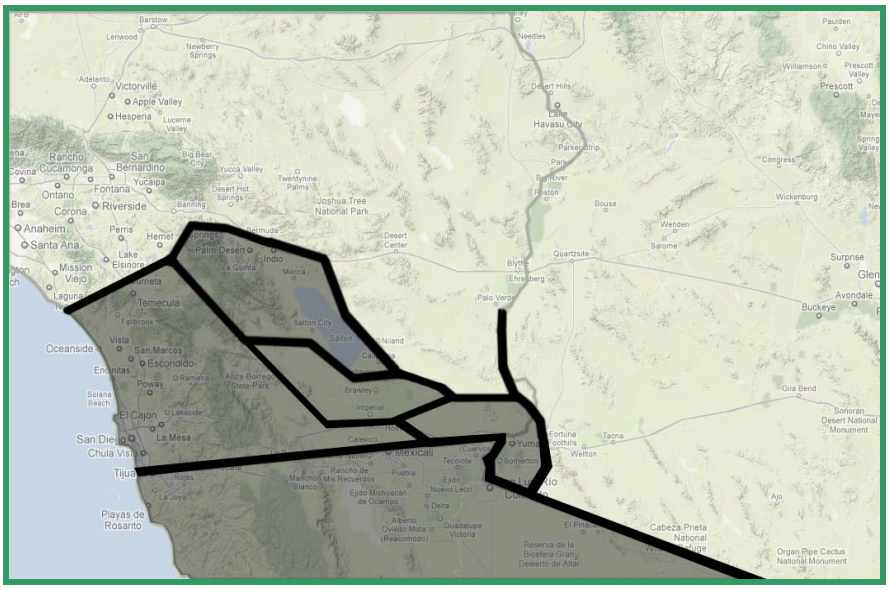
**Yuma Separates (Time: 15.38.23.12)**




**CFE Separates (Time: 15.38.23.13)**



## SDG&E, CFE, and Yuma Blackout ( by 15.38.30)



## H. System Restoration

None of the affected entities needed to implement black start plans because they all were able to access sources of power from their own or a neighbor's system that was still energized. The restoration process generally proceeded as expected, and some entities restored load more quickly than they had expected. The following charts indicate how long it took the affected entities to fully restore their lost load, generation, and transmission.

| LOAD RESTORATION EFFORTS | | | | | |
|---|---|---|---|---|---|
| Entities | Demand Interrupted (MW) | Time Until Demand Fully Restored | Date Restored | 100 % Demand Restored (hrs) | Number of Customers Affected |
| SDG&E | 4,293 | 03:23 | 9/9/11 | 12 | 1.4 Million |
| CFE | 2,205 | 01:37 | 9/9/11 | 10 | 1.1 Million |
| IID | 929 | 21:40 | 9/8/11 | 6 | 146,000 |
| APS | 389 | 21:12 | 9/8/11 | 6 | 70,000 |
| WALC | 74 | 22:23 | 9/8/11 | 6.5 | 5[58] |

**58** The majority of WALC's lost load (64 MW) affected APS customers. SCE lost 117 fringe load customers who were served by the SDG&E system.

| GENERATION RESTORATION EFFORTS | | | | |
|---|---|---|---|---|
| Entities | Generation Lost (MW) | Time Generation Restored | Date Restored | Generation Restored (hrs) |
| SCE | 2,428 | 06:33 | 9/12/11 | 87 |
| SDG&E[59] | 2,229 | 06:20 | 9/10/11 | 39 |
| CFE | 1,915 | 23:43 | 9/10/11 | 56 |
| IID | 333 | 20:42 | 9/8/11 | 5 |
| APS | 76 | 20:37 | 9/8/11 | 5 |

| TRANSMISSION RESTORATION EFFORTS | | | | |
|---|---|---|---|---|
| Entities | Final Transmission Restored (kV) | Time Transmission Restored | Date Restored | Transmission Restored (hrs) |
| IID | 230<br>161 | 03:37<br>00:31 | 9/9/11<br>9/9/11 | 12<br>9 |
| SDG&E | 500<br>230 | 17:36<br>03:47 | 9/8/11<br>9/9/11 | 2<br>12 |
| APS | 500 | 16:51 | 9/8/11 | 1.5 |
| WALC | 161 | 17:09 | 9/8/11 | 1.5[60] |
| CFE | 230<br>115 | 04:03<br>01:58 | 9/9/11<br>9/9/11 | 12.5<br>10 |

**59** According to SDG&E, after restoring the SDG&E transmission systems, CAISO took over restoring SDG&E's generation.

**60** This represents the time it took WALC to restore its 161/69 kV Gila transformers, however, none of WALC's transmission lines were lost in the outage.

WECC RC could have taken a more active role in coordinating the restoration efforts. WECC RC has the largest area of visibility and more advanced real-time study tools than the TOPs. During a multi-system restoration, issues are likely to arise between neighboring BAs and TOPs that may require either a neutral decision maker, or rapid technical analysis of unplanned system conditions. WECC RC is uniquely situated to provide such assistance. WECC RC should clarify its role, and the real-time information it can provide, in emergency situations like a multi-system restoration. WECC RC should also specifically address the issue of coordination among other functional entities (like BAs and TOPs) in its operating area, outlining the areas of responsibility during system restoration and other emergencies.

The inquiry reviewed recordings and other data about restoration which disclosed the following incidents that could have benefitted from better WECC RC coordination and assistance in real time:

- A 30-minute debate occurred between SCE, which was attempting to provide cranking power to SDG&E to restore SDG&E's system, and the SONGS operators, about the conditions necessary for resetting the SONGS separation scheme lockout relay.
- Recordings showed a lack of clarity among WECC RC, CAISO, and SDG&E about responsibilities for restoration efforts. Among other things, this resulted in a SONGS operator making a unilateral decision to open a circuit breaker on the line responsible for restoring power to SDG&E's system, leaving the line in a less reliable configuration (connected to a single bus).

# IV. CAUSES, FINDINGS, AND RECOMMENDATIONS

## A. Planning

### Next-Day Planning

- **Background**

TOPs are required to perform next-day studies to identify and plan for potential limitations on their system in the day-ahead timeframe, and to coordinate these studies with their neighboring TOPs.[61] These studies provide a proactive mechanism to ensure that the system can be operated reliably and allow time to develop effective operating solutions.[62] These solutions include, among other things, effective control actions needed to return the system to a secure state in anticipated normal and contingency system conditions. The development of these plans in the day-ahead timeframe is critical because it would be nearly impossible, due to the complexity of the BPS, for control room operators to return the system to a secure operating state under stressed conditions without effective action plans developed in advance. The adequacy of next-day studies depends on how extensively and accurately facilities and next-day system conditions are incorporated into the models used for the studies. This includes consideration of a reasonably accurate, current, and complete list of external contingencies that could impact a TOP's system as well as internal contingencies that could impact external SOLs. Consistency of study inputs among all TOPs and BAs is also critical for reliable operation.

The inquiry found that the affected TOPs' and BAs' procedures for conducting next-day studies and models used in these studies vary considerably. As explained more fully below, APS does not conduct next-day studies, relying, instead, on two sets of studies, conducted on a seasonal and annual basis, that consider a list of possible, predetermined contingency scenarios and provide plans to mitigate the contingencies if violated. Meanwhile, IID has a policy of conducting next-day studies each day, but between April and October of 2011, it failed to perform the required studies on a daily basis. All other affected TOPs conduct next-day studies, but they use models that do not

[61] *See* NERC Reliability Standard TOP-002-2b R11.

[62] *See, e.g.*, NERC Reliability Standard TOP-002-2b ("Current operations plans and procedures are essential to be prepared for reliable operations, including response for unplanned events.").

adequately reflect next-day operations of facilities in networks external to them. These TOPs' next-day studies also do not consider a full list of internal and external contingencies that could impose limitations on their daily operations or external operations. Moreover, most of these TOPs' next-day studies do not consider the impact of sub-100 kV facilities on BPS reliability, such as the impact of IID's CV transformers.

WECC RC is the highest level of authority responsible for reliable operation of the BPS in the Western Interconnection, with the authority to prevent or mitigate emergency operating conditions in the next-day and real-time timeframes. As such, WECC RC also conducts next-day studies for the entire Western Interconnection and builds its model from the previous day's peak State Estimator case, which includes all facilities operated at 100 kV and above and some sub-100 kV facilities. WECC RC then incorporates forecast information, which typically includes transmission outages as provided by TOPs, generation outages or derates of 50 MW or greater as provided by TOPs, as well as load forecasts, expected net interchange, and unit commitment forecast data from BAs. While WECC RC has a more extensive representation of facilities throughout the WECC footprint in its model than any individual TOP, it does not necessarily monitor or alarm for certain lower voltage facilities and facilities deemed non-BES that can impact BPS reliability. Moreover, because some of the forecasted information can change between the time the TOPs and BAs provide it to WECC RC and the time WECC RC runs its next-day studies, WECC RC's next-day studies might not accurately reflect next-day operations.

The September 8th event exposed four weaknesses with the foregoing procedures for conducting next-day studies in WECC's region. These weaknesses are detailed in the following four findings. A common theme prevails in all four findings: the affected entities do not accurately account for external next-day operating conditions or potential external contingencies that could impact their systems.

### Finding 1 Failure to Conduct and Share Next-Day Studies:

- **Not all of the affected TOPs conduct next-day studies or share them with their neighbors and WECC RC. As a result of failing to exchange studies, on September 8, 2011 TOPs were not alerted to contingencies on neighboring systems that could impact their internal system and the need to plan for such contingencies.**

### Recommendation 1:

- **All TOPs should conduct next-day studies and share the results with neighboring TOPs and the RC (before the next day) to ensure that all contingencies that could impact the BPS are studied.**

## Failure to Conduct Next-Day Studies

APS does not conduct next-day studies. Instead, it relies on two sets of studies, conducted on a seasonal and annual basis, for its daily operations. First, APS uses its summer and winter seasonal studies for the non-WECC Rated Paths within its transmission system. APS performs these studies on a model that it builds from the WECC heavy summer base case. In a coordinated effort with other entities in Arizona, it updates this WECC base case with anticipated loads and resources from the state. APS then adds a detailed representation of the entire state's network, including its own subtransmission system down to the 12 kV distribution system, to finalize the summer model. To create its winter model, APS modifies the summer model with winter peak conditions throughout Arizona.

Once these summer and winter models are complete, APS studies a set of predetermined contingencies, and relies on the results to determine the response of its transmission system to single and multiple contingencies during peak load conditions with planned outages modeled. The studies' list of contingencies is based on past studies, operating experience, and engineering judgment. The studies also establish mitigating measures for contingencies that do not meet loading or voltage guidelines.

Second, APS relies on a single manual, developed annually, as a guide for its daily operations on four Rated Paths within its system. This manual is the result of studies of possible, predetermined contingencies on Rated Paths. The results and operational instructions in this manual are based on seasonal models that APS develops in coordination with four WECC regional study groups, led by CAISO. CAISO first sends a base case to each study group to update with topology changes for the upcoming season. Individual members of each study group also update the model with details from their systems. CAISO then incorporates all of the updates and stresses key Paths in California before sending the model back to the study groups. APS uses this model as a starting point to study the four Rated Paths in its system. APS analyzes the resulting peak-load model using a predetermined set of single and double contingency events that are focused primarily on high-voltage transmission outages to determine required actions to secure the system for the next most critical N-1 event.[63] The manual directs APS to rerate relevant Path(s) and identifies necessary mitigating measures as long as the contingency (or multiple contingency) scenario is included in the manual. The manual, however, may not include a particular contingency (or multiple contingency) scenario, or

[63] APS's manual covers only 500 kV and 345 kV facilities, and nothing lower.

may not accurately reflect the internal and external system topology for the day in question, resulting in the potential for unforeseen circumstances.

Thus, APS uses seasonal studies for non-Rated Paths and the manual for Rated Paths as tools in the day-ahead timeframe, without any additional analysis to validate that the tools remain valid for the next day's specific configuration and operation, such as transmission or generation outages external to APS's footprint that were not anticipated at the time the base seasonal study was performed. APS maintains that these tools are sufficient for day-ahead purposes because they include the most severe contingencies identified in its system. This viewpoint overlooks the purpose of next-day studies—to plan for next-day operations *in light of conditions that change daily*. By relying on tools based on studies conducted on a seasonal and annual basis, APS cannot account for all plausible daily scenarios. For typical days that fall within the boundaries of the underlying studies and analysis, APS's tools may be viable. For atypical days where conditions fall outside the studied boundaries, however, this approach may not be adequate. For example, September 8, 2011, was an atypical day not contemplated by APS's manual, as the manual did not account for various generation outages in effect for maintenance.

Between April and October 2011, IID also did not consistently perform adequate next-day analyses for each day. Although IID had a policy of conducting separate next-day analyses for each new day, it failed to consistently perform the required analyses. Specifically, IID produced a document each new day showing various changes in weather, load and generation forecasts, planned facility outages, potential contingency violations, or mitigation measures for identified contingencies, but did not always perform the underlying power flow studies for each day between April and October 2011. On average, between April 2011 and October 2011 IID actually performed a study no more than two times per week. For the other days, IID simply referenced past studies. For example, it appears that IID did not perform a separate, updated study for September 8, 2011, because the powerflow study case provided for this day does not match the contingency results included in the daily operations guide for the day. In other words, it appears that for September 8, 2011, IID simply changed the forecasted data without actually performing the next-day study. Instead, IID referenced a previous study. The referenced study, however, was not valid because it did not match the load and generation dispatch data for the day, and there were differences in projected overloads reported as potential contingencies. IID's next-day studies were purportedly reviewed by IID for accuracy, but these discrepancies were not identified. IID discovered this issue during the course of the inquiry and is in the process of implementing corrective actions to ensure accurate next-day analyses are completed in the future.

Finally, the inquiry heard on more than one occasion from TOPs, including APS, that WECC RC was responsible for conducting next-day studies or that WECC RC should conduct next-day studies that TOPs are currently responsible for conducting. WECC RC's next-day studies for the entire Interconnection, however, are not intended to substitute for the TOPs' next-day studies of their own systems.

## Failure to Effectively Share and Coordinate Next-Day Studies

In addition to finding that not all entities conduct next-day studies, the inquiry found problems with sharing and coordination among the affected TOPs that do conduct such studies. The affected TOPs do not consistently share their studies with neighboring TOPs, BAs, and the RC. TOPs generally provide studies to WECC RC only if the RC identifies an issue in its study and specifically asks to review a TOP's study. In addition, WECC RC's method of sharing its next-day studies with other entities is not effective. Specifically, WECC RC's practice is to share the results of its next-day studies when conditions warrant, or when it receives a request for a study result.[64] WECC RC posts on a secure Internet portal a list of limitations or SOLs identified by its next-day studies for individual TOPs and BAs to view, but it is up to TOPs and BAs to access this list. Also, this list contains only issues that WECC RC deems significant and does not include basic, next-day operating conditions, such as scheduled outages.

One example of the adverse consequences of these sharing and coordination issues relates to the 600-plus MW of TDM generation that was offline for maintenance on September 8th. The TDM generation outage was included in WECC RC's and CAISO's next-day studies, and posted on CAISO's website, but not incorporated into other entities' next-day models and studies.[65] WECC RC receives outage information from TOPs and BAs through its Coordinated Outage System (COS). While TOPs and BAs submit their own information into COS, they cannot access information submitted by others. IID could have benefitted from knowledge of the TDM outages. The TDM units radially connect to the Imperial Valley substation, jointly owned by IID and SDG&E. If the TDM units had been online, they could have mitigated northern IID overloads on the

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[64] *See* WECC Reliability Coordination, Operations Planning, Version 3.0, June 22, 2011, at 6, *available at* http://www.wecc.biz/awareness/Reliability/WECC RC Operating Procedures/WECC RC Operations Planning.pdf.

[65] CAISO knew about the outages because the TDM units participate in the CAISO market. CAISO posts daily outage unit status reports on its public website that provide the best available data at the date and time of the report, for generation units that participate in CAISO's market. These outages are posted at http://www.caiso.com/market/Pages/OutageManagement/UnitStatus.aspx. In CAISO's archives, the TDM units are shown on outage on September 7 and 8, at a minimum. Dispatch details, however, are not included. WECC RC receives CAISO's outage unit status reports daily by email and was aware of the outages. However, IID and APS did not know about the TDM outages.

CV and Ramon transformers that resulted when H-NG tripped. If IID had learned about these outages from WECC RC or CAISO, it could have incorporated the outages in the day-ahead timeframe and dispatched additional generation, or taken other control actions, to compensate for the overloads on its system caused by having these generators offline and the H-NG tripping.

The September 8th event illustrates that conducting next-day studies and sharing the results of such studies are critical to allow TOPs to identify and plan for potential contingencies.

**Finding 2 Lack of Updated External Networks in Next-Day Study Models:**

- **When conducting next-day studies, some affected TOPs use models for external networks that are not updated to reflect next-day operating conditions external to their systems, such as generation schedules and transmission outages. As a result, these TOPs' next-day studies do not adequately predict the impact of external contingencies on their systems or internal contingencies on external systems.**

**Recommendation 2:**

- **TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and transmission outages and scheduled interchanges, which can significantly impact the operation of their systems. TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities. Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs.**

As a starting point for their next-day studies, the affected TOPs use models from either a TOP's seasonal base case or the previous day's EMS model, if available. The seasonal base case represents next-day operating conditions internal to the TOPs' systems, but leaves external networks exactly as they were represented in the WECC seasonal base case. The affected TOPs' EMS models sometimes include only one or two buses outside each TOP's internal footprint. Thus, neither type of day-ahead model contains actual day-ahead forecasts of system conditions external to each TOP's system. For example, leading into September 8th, the affected TOPs had limited knowledge of the current status of transmission facilities, expected generation output, and load predictions outside their footprints. Consequently, their next-day studies could not adequately predict the impact of external contingencies on their systems or of internal contingencies on external systems.

IID's next-day study for September 8th illustrates the adverse effects of not accounting for external next-day planned operations. IID used the WECC heavy summer seasonal base case to model external conditions for its next-day study for September 8th. This base case reflects that most external generation is online to meet summer peak loads. A heavy summer base case does not accurately represent a shoulder season day like September 8th. By September, both generation and transmission maintenance had started.

For example, on September 8th TDM generator units in Mexico, totaling more than 600 MW, were offline for maintenance. These units are external to IID and radially connect to IID's jointly owned Imperial Valley substation. When online, this generation can help to mitigate overloads on the CV and Ramon transformers in IID's system. Because IID relied on a heavy summer seasonal model for external networks and did not incorporate any updates about the TDM generation, its next-day study did not reflect the maintenance outage of these units. With the TDM generation incorrectly represented as being online, IID's next-day study did not correctly identify how much the loss of H-NG would overload IID's transformers in its 92 kV system. In fact, IID's next-day study for September 8, 2011, did not show that the loss of H-NG would overload the CV transformers to their trip point.[66] If IID had learned about the TDM outages (whether from CAISO's website or BY some other method) and incorporated the information into its model, it could have dispatched additional generation, adjusted load, or taken other control actions before the loss of H-NG to mitigate such overloading.

As mentioned above, WECC RC receives next-day data from the entities through interfaces such as the COS. WECC RC is well-situated to facilitate data-sharing among the 37 BAs and 53 TOPs in the WECC footprint. Given the large number of BAs and TOPs in the WECC region, some of which are relatively small in size and resources, central coordination and facilitation may be necessary to ensure that all BAs and TOPs accurately reflect next-day operating conditions external to their system.[67] WECC RC has been working to facilitate data sharing by drafting and circulating a universal

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[66] The heavy summer base case has more than 1,000 MW more generation in the affected area than was available on September 8, 2011. In addition to not representing the offline generation, IID's study, by relying on the heavy summer base case, did not accurately reflect the flow on H-NG. The heavy summer base case shows flow on H-NG as 1,118 MW, while actual flow on H-NG at the time of the trip was 1,391 MW.

[67] Under current WECC RC procedures, the RC only shares the results of its operational planning analyses if the results indicate the need for specific operational actions to prevent or mitigate an instance of exceeding an operating limit. WECC Reliability Coordination, Operations Planning, Version 3.0, June 22, 2011, at 6, *available at* http://www.wecc.biz/awareness/Reliability/WECC RC Operating Procedures/WECC RC Operations Planning.pdf.

nondisclosure agreement. As this report was being finalized, less than 30 of the approximately 100 discrete entities within WECC had signed the agreement.[68]

### Finding 3 Sub-100 kV Facilities Not Adequately Considered in Next-Day Studies:

- **In conducting next-day studies, some affected TOPs focus primarily on the TOPs' internal SOLs and the need to stay within established Rated Path limits, without adequate consideration of some lower voltage facilities. As a result, these TOPs risk overlooking facilities that may become overloaded and impact the reliability of the BPS. Similarly, the RC does not study sub-100 kV facilities that impact BPS reliability unless it has specifically been alerted to issues with such facilities by individual TOPs or the RC has otherwise identified a particular sub-100 kV facility as affecting the BPS.**

### Recommendation 3:

- **TOPs and RCs should ensure that their next-day studies include all internal and external facilities (including those below 100 kV) that can impact BPS reliability.**

The September 8th event showed that some sub-100 kV facilities can have significant impacts on BPS reliability, such as causing instability or cascading outages. Yet, it appears that these facilities are not adequately considered in the day-ahead timeframe. For example, IID's 92 kV network runs parallel to two major transmission Paths: (1) Path 44, which connects to the SWPL via the Palo Verde-Devers 500 kV line (part of Path 49) and runs to the north of IID; and (2) the SWPL, which runs to the south of IID. Given the parallel nature of its system, IID's 92 kV system is forced to carry a significant portion of any east-west power flows whenever segments of Path 44 or the SWPL are out of service.

Because none of the affected TOPs, besides IID, considered IID's 92 kV network in their next-day studies, they were not aware how their internal contingencies could affect IID's 92 kV network, or how an overload on IID's 92 kV network could affect their systems. For example, APS does not routinely study IID's lower voltage facilities, including the CV and Ramon transformers, in the day-ahead timeframe. APS uses seasonal studies and its operations manual as its tools in the day-ahead timeframe. While the model used for the seasonal studies physically has IID's 92 kV network represented, neither the model nor the operations manual are used to consider the next day's specific configuration and operation, such as transmission or generation outages external to APS's footprint that were not anticipated at the time the seasonal study and

[68] The agreement does address market concerns by requiring entities who participate in data-sharing to respect the separation of market and operations functions.

manual were updated. As a result, APS was not able to predict what occurred on IID's system—increased flows and overloading on its 92 and 161 kV transformers and transmission lines—when H-NG tripped offline. Similarly, affected TOPs other than IID do not consider in their day-ahead planning how the loss of the CV and Ramon transformers, leading to the S Line RAS operation, could adversely affect their internal systems. Accordingly, TOPs should revise their next-day study practices to account for all facilities, including those operated below 100 kV, that impact BPS reliability.

WECC RC also did not adequately consider sub-100 kV facilities not identified as BES that can have significant impacts on BPS reliability. While WECC RC does model IID's CV transformers in its next-day studies, prior to September 8, 2011, it did not "flag" them in its studies for active monitoring.[69] This means that WECC RC had data showing that the transformers would overload under certain conditions, but the overloads were not identified by alarms to be seen by RC operators. WECC RC did not actively monitor the CV transformers in its next-day studies because they are below 100 kV and IID had not alerted WECC RC to any issues that would warrant monitoring of the transformers. Given the CV transformers' impact on BPS reliability, WECC RC should actively monitor these transformers.[70]

### Finding 4 Flawed Process for Estimating Scheduled Interchanges:

- **WECC RC's process for estimating scheduled interchanges is not adequate to ensure that such values are accurately reflected in its next-day studies. As a result, its next-day studies may not accurately predict actual power flows and contingency overloads.**

### Recommendation 4:

- **WECC RC should improve its process for predicting interchanges in the day-ahead timeframe.**

Interchanges are energy transfers that cross BA Areas. Interchanges can affect flows across transmission systems, so forecasting accurate interchanges is important in the day-ahead timeframe to plan for potential overloading. WECC RC's process for estimating scheduled interchanges is not adequate to ensure that the scheduled interchanges incorporated into its next-day studies are accurate. Under this process, by 10:00 AM each day BAs provide WECC RC with all interchanges they have approved for

[69] To aid in effectively and efficiently processing and analyzing reliability data for the entire Western Interconnection, WECC RC has the option of flagging a subset of facilities for active monitoring in its studies. It has since updated this feature to flag the CV transformers for monitoring.

[70] WECC RC has implemented new procedures since September 8, 2011, to monitor RTCA results for the CV transformers.

the next day. The BAs typically submit this information once per day without any subsequent updates. WECC RC then validates these scheduled interchanges by comparing the values with what the BAs provided the prior day and with what WECC RC's state estimator observed in the prior days and weeks.

The accuracy of interchange data in WECC RC's next-day studies could be improved by allowing for updates closer to real time. BAs' interchange data are likely to change after their 10:00 AM submittal to WECC RC. Some BAs have automated systems, which send updates of interchange data to WECC RC. Most BAs submit the data manually, only once at 10:00 AM. Inclusion of a process or requirement for BAs to update their scheduled interchanges after their 10:00 AM submission would increase the likelihood of accurate interchange data.

The accuracy of interchange data affected WECC RC's next-day study for September 8, 2011. Specifically, the scheduled interchanges reflected in WECC RC's next-day study for September 8, 2011, were not sufficiently accurate to predict that IID's CV 230/92 kV transformers would overload to their trip point upon the loss of H-NG. After the event, WECC RC ran its next-day study using *actual* interchanges, and found that the CV transformers would overload beyond their tripping threshold upon the loss of H-NG. If WECC RC had used more accurate net interchange data and flagged the CV transformers for monitoring, it could have learned of the issues with these transformers and alerted IID or issued directives for control actions to mitigate the situation, such as increasing generation or shedding load.

## Seasonal Planning

### Background

Following a set of disturbances in the Western Interconnection during the summer of 1996, WECC established a new seasonal planning structure designed to avert system-wide disturbances while maximizing the commercial availability of transmission capacity. This new structure involved the creation of the Operating Transfer Capability Policy Committee (OTCPC). The purpose of the OTCPC was to provide coordinated standard development and determination of seasonal Operating Transfer Capabilities (OTCs), or Operating Transfer Limits,[71] within the Western Interconnection.[72]

[71] OTCs are now known as SOLs.

[72] The OTCPC itself was abolished and replaced with a new structure in June 2011; however, planning for the seasonal period in which the blackout occurred was performed under the OTCPC structure, so the inquiry's analysis focused on the OTCPC structure.

Among other things, the OTCPC was designed to be responsible for determining which transmission Paths should be studied, facilitating OTC dispute resolution, ensuring that seasonal studies maintain consistent standards and methodologies, and approving seasonal studies of OTC limits. To that end, the OTCPC was charged with reviewing and approving study plans and technical simulation results; developing policies and procedures addressing seasonal OTCs; establishing working groups such as subregional study groups and the Operating Procedures Review Group; addressing OTC seams issues between subregions; and providing technical guidance.

The seasonal study plans that are reviewed and approved by the OTCPC were created by a set of four subregional study groups (sometimes referred to as SRSGs or simply subregions). There were four groups: (1) the California/Mexico Operations Study Subcommittee (OSS); (2) the Northwest Operational Planning Study Group (NOPSG); (3) the Rocky Mountain Subregional Study Group (RMSG); and (4) the Southwest Area Study Group (SASG). The affected entities were members of two of these groups: the OSS (CAISO, SDG&E, SCE, CFE, and IID) and the SASG (APS, WALC).

On an annual basis, each subregional study group reviewed the Paths in its subregion to determine which Paths should be studied and the system conditions under which they should be studied. Then, seasonally, the four subregional study group chairs submitted their recommendations of which Paths to study to the OTCPC for review and approval. Following OTCPC's approval, the studies were performed in accordance with the OTC study process. This process began with establishment of an initial "base case" by WECC staff, with input from representatives of each subregional group. The "base case" is a computer model of projected or starting power system conditions for a specific point in time. For the 2010-2011 planning year, five base cases were used.[73] Once the comments from the four subregional representatives were incorporated, the final cases were made available via WECC's web site for adjustment and modification by subregional members in order to forecast expected seasonal conditions on the system. The subregional members performed their own seasonal studies, and then met to discuss the results. A subregional seasonal planning case was produced on this basis, but no further studies were performed. Subregional seasonal cases were shared among the four subregions via liaisons from the other subregions. No comprehensive WECC-wide Path rating study was prepared on the basis of the four subregional studies.

[73] These included low summer load, high summer load, low winter load, high winter load, and high spring load.

In addition to, and apart from, the seasonal planning studies just described, TOPs also conduct their own seasonal studies focusing on their own internal networks. These internal studies follow a different process from the seasonal Path rating studies, though both begin with the WECC base case. Internal seasonal studies, however, are not aggregated or reviewed at the subregional level. Instead, TOPs generally replace the information from the WECC base case with more accurate and granular detail for their own areas only. Once updated, the TOPs perform contingency analyses for their own internal purposes. They then share with their neighbors the results of these operational studies, which typically contain only the default data from the WECC base case for everything outside of their own areas.

The inquiry identified a number of issues relating to both types of seasonal planning by the affected entities. These issues impaired the accuracy and effectiveness of the seasonal studies by excluding, in various ways, pertinent issues and information that should have been taken into consideration.

### Finding 5 Lack of Coordination in Seasonal Planning Process:

- **The seasonal planning process in the WECC region lacks effective coordination. Specifically, the four WECC subregions do not adequately integrate and coordinate studies across the subregions, and no single entity is responsible for ensuring a thorough seasonal planning process. Instead of conducting a full contingency analysis based on all of the subregions' studies, the subregions rely on experience and engineering judgment in choosing which contingencies to discuss. As a result, individual TOPs may not identify contingencies in one subregion that may affect TOPs in the same or another subregion.**

### Recommendation 5:

- **WECC RE should ensure better integration and coordination of the various subregions' seasonal studies for the entire WECC system. To ensure a thorough seasonal planning process, at a minimum, WECC RE should require a full contingency analysis of the entire WECC system, using one integrated seasonal study, and should identify and eliminate gaps between subregional studies. Individual TOPs should also conduct a full contingency analysis to identify contingencies outside their own systems that can impact the reliability of the BPS within their system and should share their seasonal studies with TOPs shown to affect or be affected by their contingencies.**

No comprehensive WECC-wide seasonal studies are performed. With respect to seasonal Path rating studies, a representative or leader from each subregion adapts the WECC base case on the basis of input from subregional members, and then makes these revised cases available to the other subregional members for review, comment, and approval. The subregional leader then conducts the seasonal studies concentrating only on the rated Paths in the subregion. The results of the seasonal Path rating studies are

shared and discussed first among the subregion's members, and then with the other subregions, but neither WECC RE nor the OTCPC performs or mandates any further seasonal studies, and no new WECC-wide seasonal study is performed to reflect the input of all of the subregions. Instead, representatives of the subregional groups gather informally to discuss the results of their seasonal studies and rely on experience and engineering judgment to identify and resolve any issues.

The events of September 8, 2011, illustrate that this process is not adequate: the tripping of one line in a rated Path—H-NG, which is part of Path 49—ultimately led to the tripping of other lines in other rated Paths, including Paths 44 and 45. Focusing exclusively on Path ratings—and solely on a subregional basis—ignores network facilities that can impact rated Paths (and vice-versa) and does not account for the interrelationships of Paths and other facilities across WECC's subregions.

With respect to the internal seasonal studies, there is even less coordination. TOPs generally perform internal seasonal studies using models that include detailed data for their own system, but default to WECC base case data, which may not be sufficiently detailed or updated, for everything else. TOPs perform contingency analysis for their own internal areas using this model. No study is done to identify the impact of external contingencies on the TOP's system, or the impact of the TOP's internal contingencies on the SOLs of other TOPs. TOPs provide the results of their internal seasonal studies to neighboring TOPs for informational purposes, after which those TOPs may or may not provide comments.

In all, this situation indicates that the TOPs' internal seasonal planning studies are too heavily reliant upon the assumptions underlying and reflected in a single WECC base case, and do not consider and study impacts of variations from that base case.

The September 8th event demonstrated one example where better integration of seasonal studies across two subregions is needed. When H-NG (part of Path 49) tripped, approximately 12% of the flow from that line, which is located in the SASG subregion, was transferred across IID's 230/92kV transformers, via the IID 92kV local network to the southern IID 161 kV network, which are all in the OSS subregion. This additional flow on IID's CV transformers ultimately resulted in cascading outages and impacted Paths 44 and 45. The affected entities were unaware of this potential inter-Path impact, because the SASG and OSS studies had not been jointly considered. Moreover, since the subregional studies concentrate only on Path ratings, this flow transfer was not apparent. If the seasonal studies of SASG and OSS had been better coordinated and more rigorously analyzed, the potential for the loss of H-NG to overload IID's 92 kV network could have been identified and mitigation plans developed.

### Finding 6 External and Lower-Voltage Facilities Not Adequately Considered in Seasonal Planning Process:

- **Seasonal planning studies do not adequately consider all facilities that may affect BPS reliability, including external facilities and lower-voltage facilities.**

### Recommendation 6:

- **TOPs should expand the focus of their seasonal planning to include external facilities and internal and external sub-100 kV facilities that impact BPS reliability.**

As noted above, TOPs performing subregional Path rating studies do not sufficiently account for the impact of facilities external to their subregion, or facilities within their subregion that are not part of a rated Path. Moreover, no WECC-wide Path rating study is performed to harmonize and analyze the impact of one subregion on the rest of the subregions.

The problem with this approach is illustrated in the example cited above: The tripping of a part of one rated Path, H-NG, which is part of Path 49, led to the tripping of portions of other rated Paths. The mechanism whereby these other trips were triggered was the transfer of flow across low-voltage (below 100 kV) facilities that were located in a different subregion. Under the approach to Path rating studies in place at the time, it would have been impossible for WECC RE or TOPs to anticipate and study this possibility, because it occurred across subregions, indirectly, via lower-voltage facilities. Even if seasonal Path rating studies had been performed across subregions, these studies would not have anticipated this possibility, unless they also took into account lower-voltage facilities, which they presently do not.

The internal seasonal planning studies of the various TOPs are subject to similar omissions, although these studies encompass more than just the rated Paths and contain more detail than the Path rating studies. The practices of individual TOPs differ, but none contains sufficient detail and accuracy with respect to facilities outside their own footprints, as well as lower-voltage facilities. IID, for example, has explained that it "does not identify or study components outside of the IID territory below 100 kV for impacts on the BPS reliability in its territory," nor does it "identify or study components inside of the IID territory below 100 kV for impacts on the BPS reliability outside of its territory."

Similarly, while CAISO studies in its seasonal planning process "all of the transmission components that it operates, some of which are below 100 kV," it has also

acknowledged that it "does not have the necessary information to accurately study transmission components below 100 kV outside of its territory to determine if they have an impact on the BPS reliability in [CAISO's] service territory."

The events of September 8, 2011, demonstrate that sub-100 kV facilities in parallel with BPS systems can have a significant effect on BPS reliability. The loss of H-NG caused the overloading and tripping of both 230/92 kV transformers at CV, which in turn caused another sub-100 kV transformer to trip at Ramon, which led to the cascading outages discussed in detail above. This possibility was not studied as part of the seasonal studies by any of the TOPs, other than IID, because the CV transformers' secondary windings are below 100 kV. The seasonal studies conducted by affected TOPs, other than IID, did not study the impact of the CV transformers. If the CV transformer contingency overloads had been identified as limiting elements in the seasonal plans, the cascading outages might have been avoided or lessened by having pre-contingency mitigation in place, such as increasing generation on IID's 92 kV system.

### Finding 7 Failure to Study Multiple Load Levels:

- **TOPs do not always run their individual seasonal planning studies based on the multiple WECC base cases (heavy and light load summer, heavy and light load winter, and heavy spring), but, instead, may focus on only one load level. As a result, contingencies that occur during the shoulder seasons (or other load levels not studied) might be missed.**

### Recommendation 7:

- **TOPs should expand the cases on which they run their individual planning studies to include multiple base cases, as well as generation maintenance outages and dispatch scenarios during high load shoulder periods.**

WECC created five base cases for the 2010-2011 season— heavy and light load summer, heavy and light load winter, and heavy spring—intended to capture the spectrum of possible loading configurations at different times of the year. The inquiry found that some of the affected TOPs deemed it unnecessary to run individual planning studies based on the multiple WECC base cases. Instead, these TOPs identified some subset of these base cases that they concluded were most relevant to their concerns and ran studies based on only that subset of base cases. Some TOPs employed only one base case—the heavy load summer base case—for planning the season during which the September 8, 2011 blackout occurred. By limiting the run of planning studies to a small subset of base cases, TOPs restrict their ability to anticipate and respond to contingencies arising in the context of load levels that vary significantly from those in the subset of base cases upon which their studies were predicated.

As noted above, September 8, 2011 was a very hot day in the region, and scheduled flows in the IID footprint were near record peaks. The high demand on September 8th was indeed similar to what would have been modeled in a heavy load summer seasonal study. The generation picture, however, was very different. By September 8, 2011 generation maintenance—which is not typically scheduled for summer peak days—had begun. The "heavy peak" summer study base cases that were actually used for September 8th therefore had built into them the incorrect assumption that there would be minimal maintenance—i.e., that most generation would be on line—and thus did not account for the normal resumption of facility maintenance in the shoulder season.

If IID's seasonal studies had assumed even a modest decrease in the available generation, they might have enabled IID to anticipate and prevent the events that occurred on its system. IID was unaware of the TDM maintenance outages, but if it had conducted a shoulder season study, it might have been operating in a mode that more accurately reflected actual operating conditions on that day and could have potentially avoided the overloading of CV transformers to the tripping point. This lack of awareness illustrates the risks of not separately modeling the shoulder months such as September, when facility maintenance has begun but demand could remain or become very high. During these times, generation to serve load may come from other areas, changing flow patterns from those that typically occur on a normal summer peak day in which most generation is on line.

### Finding 8 Not Sharing Overload Relay Trip Settings:

- **In the seasonal planning process, at least one TOP did not share with neighboring TOPs overload relay trip settings on transformers and transmission lines that impacted external BPS systems.**

### Recommendation 8:

- **TOPs should include in the information they share during the seasonal planning process the overload relay trip settings on transformers and transmission lines that impact the BPS, and separately identify those that have overload trip settings below 150% of their normal rating, or below 115% of the highest emergency rating, whichever of these two values is greater.**

As discussed in greater detail below, the relay trip settings of IID's CV 230/92 kV transformers were set very low, just above the facilities' emergency rating. These settings effectively meant that IID's system operators had very little time to respond to the overload resulting from the loss of H-NG beyond emergency ratings and could not rely on post-contingency mitigation. If IID's neighbors had been aware of the relay trip

settings on these transformers when preparing their seasonal studies, they would have been able to plan for the possibility of the CV transformers tripping at a lower trip point.

As a general matter, TOPs should be aware of the relay trip settings of facilities in neighboring areas that have the potential to impact portions of the BPS within their own areas, regardless of whether or not those facilities have been defined as, or deemed to be, BES facilities. This concern is particularly acute where the overload trip points of the facility in question are set below 150% of their normal rating, or below 115% of their emergency rating, because, as discussed below, such settings sharply limit the amount of time available for operators to implement post-contingency mitigation measures. These settings require that all entities that could be affected are aware and able to implement pre-contingency mitigation.

## Near-and Long-Term Planning

### Background

TPs and PCs conduct near- and long-term studies to ensure their systems are planned for reliable operation under normal operating conditions. In addition, the system facilities must remain stable in the event of single and multiple contingency scenarios. Near-term studies consider potential contingencies one to five years past the study date, and long-term studies consider potential contingencies six to ten years past the study date. The near- and long-term planning process in the WECC region involves a coordinated effort among individual TPs and PCs at the local level, Subregional Planning Groups (SPGs)[74] at the regional level, and WECC RE at the Interconnection-wide level. It is a multi-step process, performed annually.

First, TPs and PCs submit data about their internal networks to their respective SPG for each horizon year studied (i.e., years one through ten). These data include forecasted load levels and facilities projected to be in or out of service. Also, these data assume peak load conditions and, thus, reflects that most internal generation is online. Second, SPGs add information to these data based on their broad knowledge of planning projects and reliability issues within their respective regions. For example, an SPG

[74] There are five SPGs in the WECC region, each representing a specific area and composed of various members and stakeholders, including individual owners and operators of transmission networks, representatives of local government agencies, and independent developers. SPGs allow for the joint consideration of issues among individual members. APS, IID, and WALC are members of WestConnect, which performs the SPG function in the Southwest region. SDG&E and SCE are members of CAISO, which performs the SPG function in parts of California. The SPGs are involved in near- and long-term planning only and are unrelated to the SRSGs, discussed above, which deal with seasonal planning.

might add data for a particular horizon year based on its knowledge of a merchant generator's desire to connect to the grid. SPGs also consider future projects needed for reliability and the effect of environmental regulations on the future operation of generator units. Third, SPGs merge all of their members' cases to create a regional case. Fourth, WECC RE merges the various regional cases from all the SPGs to create the base case for each horizon year. WECC RE makes these cases available on its website for TPs, PCs, and SPGs to access. Finally, TPs and PCs add their own subtransmission facilities to the base cases to run their near- and long-term studies. TPs and PCs typically choose a list of contingencies to study based on past experience and engineering judgment.

As discussed below, this multi-step process has several shortcomings, which left the affected entities unprepared for the September 8th event.

### Finding 9 Gaps in Near- and Long-Term Planning Process:

- **Gaps exist in WECC RE's, TPs' and PCs' processes for conducting near- and long-term planning studies, resulting in a lack of consideration for: (1) critical system conditions; (2) the impact of elements operated at less than 100 kV on BPS reliability; and (3) the interaction of protection systems, including RASs. As a consequence, the affected entities did not identify during the planning process that the loss of a single 500 kV transmission line could potentially cause cascading outages. Planning studies conducted between 2006 and 2011 should have identified the critical conditions that existed on September 8th and proposed appropriate mitigation strategies.**

### Recommendation 9:

- **WECC RE should take actions to mitigate these and any other identified gaps in the procedures for conducting near- and long-term planning studies. The September 8th event and other major events should be used to identify shortcomings when developing valid cases over the planning horizon and to identify flaws in the existing planning structure. WECC RE should then propose changes to improve the performance of planning studies on a subregional- and Interconnection-wide basis and ensure a coordinated review of TPs' and PCs' studies. TOPs, TPs and PCs should develop study cases that cover critical system conditions over the planning horizon; consider the benefits and potential adverse effects of all protection systems, including RASs, Safety Nets (such as the SONGS separation scheme), and overload protection schemes; study the interaction of RASs and Safety Nets; and consider the impact of elements operated at less than 100 kV on BPS reliability.**

The affected entities' near- and long-term planning studies for horizon year 2011 (i.e., the studies conducted in 2001 through 2010) did not identify that the loss of a single 500 kV line in APS's territory would cause cascading outages across the territories of SDG&E, CFE, IID, and WALC. Several gaps in the near- and long-term planning process contributed to these omissions. First, TPs and PCs submit peak load data to

WECC for incorporation into the base case and, thus, the data assume that most internal generation is online to meet peak conditions. As a result, the models for 2011 did not contain accurate, realistic representations of online generation. Running studies under the assumption that most generation is online provided an unrealistic portrayal of system transfers on the day of the event.

Indeed, system transfers following the loss of H-NG were higher than the transfers seen in the base case used for near- and long-term studies. Significant flows from H-NG transferred across IID's and WALC's systems and onto Path 44. Flow on Path 44 increased by approximately 84% following the loss of the line. These large system transfers went undetected in near- and long-term studies, and the affected entities were not alerted to the need to plan for these critical system conditions. To avoid this problem in the future, TPs and PCs should study more generation dispatch scenarios to provide a more realistic projection of system transfers following contingencies.

Second, TPs and PCs do not run a full list of external contingencies during the near- and long-term planning process. Instead, they rely on experience and engineering judgment, focusing on previously identified contingencies. This can be particularly problematic in today's operating environment in which the nature and limitations of the system are rapidly changing. For example, as part of its near- and long-term planning IID studied potential contingencies on four WECC Rated Paths, but did not study the loss of H-NG. As a result, IID was not prepared for the effect on its system when that line tripped. Also, while IID's CV 230/92 kV transformers are included in the base case, some of the affected TPs and PCs did not study the potential loss of these facilities. By not considering a complete list of external contingencies that could impact their systems, TPs' and PCs' studies for horizon year 2011 were not sufficient to identify and plan for the impact of external contingencies on their internal systems or internal contingencies on neighboring systems.

Third, TPs and PCs do not study external subtransmission facilities in the near- and long-term planning process. Individual TPs and PCs add their own subtransmission facilities after the base case has been created by WECC RE, but do not add external subtransmission equipment. If external subtransmission systems were included in the base case, entities could identify the parallel flow on such lower-voltage systems that can result from transmission contingency outages. This consideration is particularly important for lower voltage systems that parallel external high voltage systems. For example, when APS's H-NG tripped, approximately 12% of its flow transferred to IID's 92 kV system. This increased flow and overloading on IID's system had a ripple effect, causing cascading outages throughout neighboring territories. Because the affected entities did not study external subtransmission systems in their near- and long-term

studies, they did not identify the potential for overloading on IID's 92 kV system or the impact on their systems from this overloading.

Fourth, TPs and PCs do not sufficiently study the interaction of protection systems in external networks in their near- and long-term planning studies. For example, some of the affected TPs and PCs did not study the interaction between the overload protection on IID's three 230/92 kV transformers, or between the protection on these transformers and the S Line RAS. Based on the pre-event conditions, the loss of one CV transformer would automatically result in the loss of the second, followed automatically by the loss of the Ramon transformer, which in turn, would result in either voltage collapse and load shedding, or overloading on the S Line. The S Line RAS is designed to mitigate overloads by tripping generation in Mexico that supplies power to IID. However, operation in this manner only served to further overload IID and WALC facilities and exacerbate system conditions on the day of the event. The affected entities should have studied the interaction of these schemes to prepare for the impacts on their systems.

### Finding 10 Benchmarking WECC Dynamic Models:

- **The inquiry obtained a very good correlation between the simulations and the actual event until the SONGS separation scheme activated. After activation of the scheme, however, neither the tripping of the SONGS units nor the system collapse of SDG&E and CFE could be detected using WECC dynamic models because some of the elements of the event are not explicitly included in those models. Sample simulations of the islanded region showed that by adding known details from the actual event, including UFLS programs and automatic capacitor switching, the simulation and event become more closely aligned following activation of the SONGS separation scheme.**

### Recommendation 10:

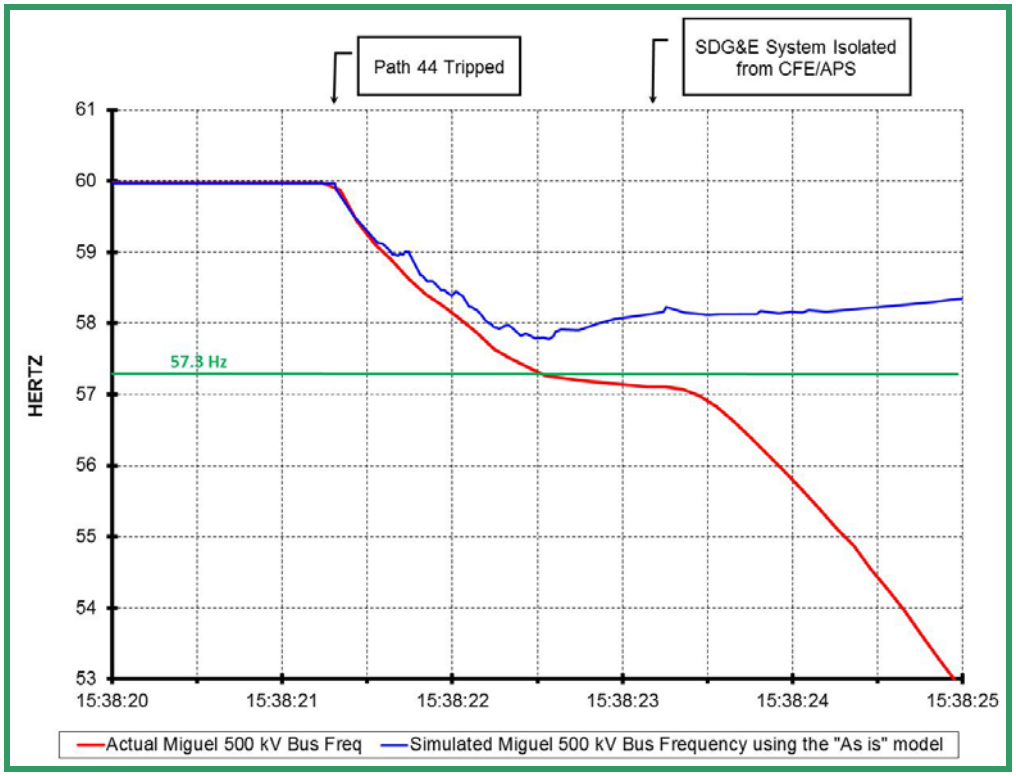
- **WECC dynamic models should be benchmarked by TPs against actual data from the September 8th event to improve their conformity to actual system performance. In particular, improvements to model performance from validation would be helpful in analysis of under and/or over frequency events in the Western Interconnection and the stability of islanding scenarios in the SDG&E and CFE areas.**

The inquiry simulated the dynamic system response of the September 8th event from prior to the loss of H-NG through the separation of Path 44 and the unsuccessful islanding of SDG&E and CFE. The team obtained very good correlation between the simulation model and the actual event until the SONGS separation scheme activated. However, neither the tripping of the SONGS units nor the system collapse of SDG&E and

CFE could be predicted using existing WECC dynamic models entities use to perform near- and long-term planning.

This inability to use the existing system models to reproduce the actual event is also evident in the post-event analysis that was prepared by SDG&E on the effectiveness of UFLS programs following the September 8th event.[75] The SDG&E post-event analysis shows that the UFLS performance should have prevented the SDG&E system from frequency collapse, similar to the "as is" results shown in ***Figure* 14**, below. However, the SDG&E analysis does not explain why the simulation results are so different than the actual system responses—i.e., successful islanding operation versus system collapse.

**Figure 14: Actual and Simulated Frequency at Miguel 500 kV Bus**




The inquiry's Modeling and Simulation team was able to obtain a simulation more closely aligned with actual measured performance by performing several sensitivity studies and adding details from the actual event, including UFLS performance, PMU

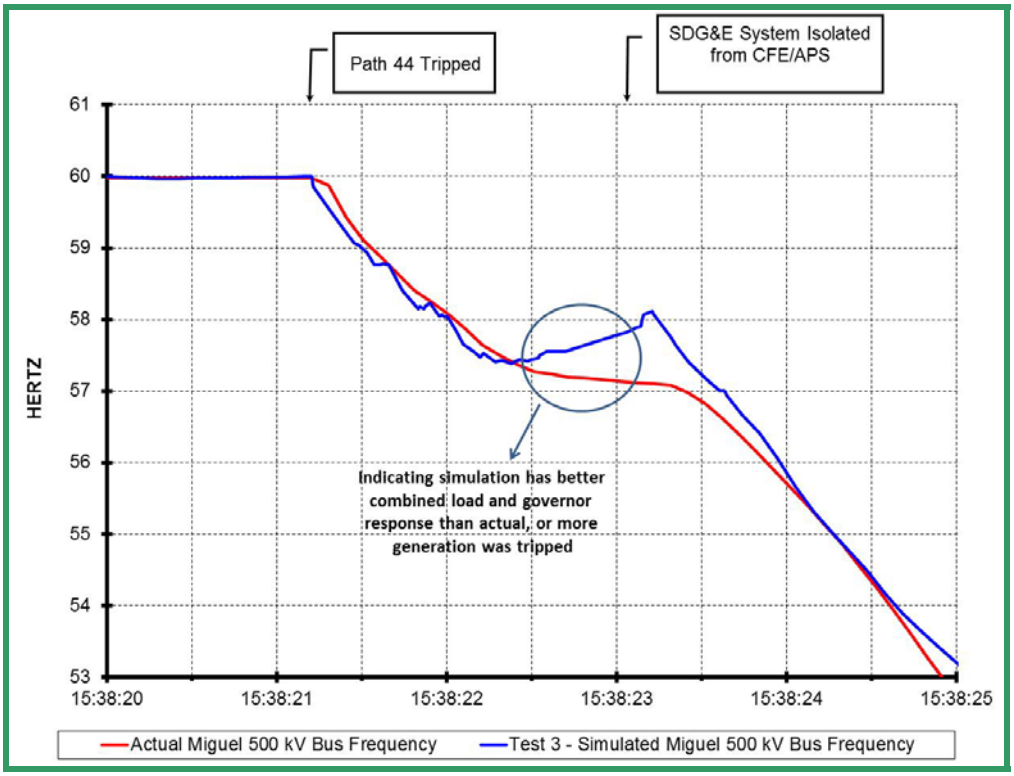
[75] Preliminary Analysis of SDG&E Off-Nominal UFLS Program Effectiveness Following September 8, 2011 Pacific Southwest Event, Performed by SDG&E, December 7, 2011.

data, and generation tripped in CFE's and SDG&E's territories. For example, one sensitivity study (referred to here as "Test 3") simulated approximately:

a) 3,080 MW of UFLS in SDG&E 1.3 seconds after Path 44 tripped (compared to 2,760 MW in "as-is" case)
b) 520 MW of UFLS in CFE after Path 44 tripped, but prior to SDG&E separation from CFE/APS (compared to 900 MW modeled in "as-is" case)
c) 589 MW of generation tripped in CFE after Path 44 tripped, but prior to SDG&E separation from CFE/APS (compared to zero in "as-is" case)
d) 1,000 MW of generation tripped in SDG&E immediately after SDG&E separated from CFE/APS (compared to zero in "as-is" case)

***Figure* 15**, below, shows results of "Test 3." As can be seen, this simulation more closely follows the actual event than the "as-is" model used in Figure 14.

**Figure 15: Miguel Frequency Actual and Simulated for "Test 3"**




The simulation studies explain the ineffectiveness of the UFLS program, despite up to 75% of SDG&E load that was shed within 1.3 seconds of the SONGS separation scheme operating. The simulation analysis confirmed findings in the inquiry's SOE that the frequency collapse was caused by generation trips and UFLS misoperations within CFE shortly after Path 44's separation, followed by additional generation trips within SDG&E around the time it separated from CFE/APS.

## B. Situational Awareness

### Background

TOPs, BAs, and RCs have system operators who constantly monitor their networks to maintain situational awareness of system conditions, identify potential system disturbances, and institute mitigating measures, as necessary. The affected entities utilize a range of tools to perform these functions. All of the entities use SCADA systems as their main monitoring tool. SCADA systems typically consist of a central computer that receives information from various RTUs and intelligent electronic devices (IEDs), located throughout the system. SCADA systems provide control center operators with real-time measurements of system conditions and can send alarms to signal a problem.

Most of the affected entities also use several other tools to study and analyze the information received from their SCADA systems. Two of the most important tools are State Estimator and RTCA. State Estimator gathers the available measurements from the SCADA system and calculates estimated real-time values for the whole system. RTCA then takes the information from State Estimator and studies "what if" scenarios. For example, RTCA determines the potential effects of losing a specific facility, such as a generator, transmission line, or transformer, on the rest of the system. In addition to studying the effects of various contingencies, RTCA can prioritize contingencies. It can also provide mitigating actions and send alarms (visual and/or audible) to operators to alert them to potential contingencies.

While most of the affected entities have and use these tools, the inquiry identified several concerns with entities' ability to adequately monitor, identify, and plan for the next most critical contingency in real time. Several areas for improvement are described in the findings below.

PMUs did not play a role in observing the September 8th event in real time, but may prove increasingly important in situational awareness. Of the affected entities, CAISO, SCE, and APS are equipped with PMUs. PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP). Their high sampling speed (up to 30 samples per second) and excellent GPS-based time synchronization offer new granularity in information about voltage phase angles and other grid conditions. PMUs are expected to be used to identify and monitor for grid stress, grid robustness, dangerous oscillations, frequency instability, voltage instability, and reliability margins. While not

yet sufficiently integrated to have been used by the affected entities in their control rooms on September 8th, as discussed earlier, PMU data proved valuable in constructing the sequence of events and other post-event analysis.

### Finding 11 Lack of Real-Time External Visibility:

- **Affected TOPs have limited real-time visibility outside their systems, typically monitoring only one external bus. As a result, they lack adequate situational awareness of external contingencies that could impact their systems. They also may not fully understand how internal contingencies could affect SOLs in their neighbors' systems.**

### Recommendation 11:

- **TOPs should engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems. They should obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the SOLs of other TOPs. In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.**

Although all of the affected TOPs use SCADA to monitor their own systems, some TOPs' situational awareness is hindered by their limited visibility into neighboring systems. Some of the affected TOPs' real-time external visibility is limited to one or two buses outside their systems. The September 8, 2011, event demonstrated that more expansive visibility into neighboring systems is necessary for these TOPs to maintain situational awareness of external conditions and contingencies that could impact their systems and internal conditions and contingencies that could impact their neighbors' systems. During the 11-minute time span of the September 8th event, entities observed changes in flows into their systems, but were unable to understand the cause or significance of these changes and lacked sufficient time to take corrective actions. If affected entities had seen and run studies based on real-time external conditions prior to the event, they could have been better prepared to redispatch generation or take other control actions and deal with the impacts when the event started.

IID, for example, is adjacent to APS, and the changes in flows on APS's system, especially on its 500 kV lines, can affect the flows on IID's system and vice versa. Yet, IID's visibility into APS's system is limited to information about the tie line between them. In fact, IID's visibility into all of its neighbors is limited to one or two buses

outside its system.[76] As a result, IID did not learn in real-time that H-NG tripped. IID also did not understand prior to the event how changes in flows or the loss of H-NG would affect its system. Immediately after H-NG tripped, IID observed loading on its CV transformers escalate rapidly, but it had not been prepared for this escalation.

If IID had greater visibility into APS's system and IID had an equivalent on its RTCA that modeled the external network using APS's real-time data instead of pseudo-generators modeled at the end of each tie line, IID's RTCA could have more accurately studied the results of a post-contingency loss of H-NG on its system before it occurred. After seeing the more accurate RTCA results, IID could have initiated appropriate control actions before H-NG tripped. Also, having real-time status of the H-NG would have better prepared IID to deal with the effects of its loss in real time.

In addition to IID not having adequate situational awareness of APS's system, the affected TOPs and BAs external to IID were not aware in real time of the effect of the post-contingency loss of IID's three 230/92 kV transformers on their systems. Losses of the CV and Ramon transformers can cause SOL violations on neighboring systems. Indeed, on September 8th, these transformer outages had a significant ripple effect and led to the cascading nature of the event. Yet, entities outside IID's footprint were not prepared for these outages and, except for WECC RC, were unaware of the outages in real time because of a lack of adequate visibility into IID's system. For example, at the time of the event, CAISO's visibility into IID's system stopped at the tie line into IID's El Centro station.

The September 8th event exposed the negative consequences of TOPs having limited external visibility into neighboring systems. Providing TOPs with the ability to observe and model external system conditions and events on a continuous real-time basis will allow them to study and plan for the impact of external conditions and contingencies before it is too late to react, as was the case on September 8th.

**76** IID has made efforts, even before the September 8th event, to receive more data points from adjacent utilities and is currently continuing this effort with all of its neighbors.

### Finding 12 Inadequate Real-Time Tools:

- **Affected TOPs' real-time tools are not adequate or, in one case, operational to provide the situational awareness necessary to identify contingencies and reliably operate their systems.**

### Recommendation 12:

- **TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.**

Although many of the affected TOPs have and use real-time tools such as State Estimator and RTCA, some of the tools are not adequate or operational to provide the situational awareness necessary to effectively monitor and operate their systems. Also, some TOPs run or view these tools infrequently, while others run RTCA, for example, every five minutes.

The alarming function on IID's RTCA provides an example of a real-time tool that does not adequately maximize situational awareness capabilities. IID's RTCA does not provide operators with any audible alarms or pop-up visual alerts when an overload is predicted to occur. Instead, IID's RTCA uses color codes on a display that the operator must call up manually to learn of significant potential contingencies. For example, IID's RTCA might show that on the next contingency, a specific element will become overloaded. However, as currently designed, the operator must go to the specific page related to this element to view this result. The result will be color coded on this page, but this code does not function as an alarm.

This design feature of IID's RTCA had negative consequences on the day of the event. Forty-four minutes prior to the loss of H-NG, IID's RTCA results showed that the N-1 contingency loss of the first CV transformer would result in overloading of the second CV transformer to its tripping point. If IID had taken action at this pre-contingency stage, it could have avoided the loss of both transformers. The IID operator, however, did not view the appropriate RTCA display and, therefore, was not alerted to the need to take action. If the operator had reviewed the RTCA results and taken necessary corrective actions, he could have relieved loading on the transformers at this

pre-event stage, and thus mitigated the severe effects on the CV transformers that resulted when H-NG tripped.[77]

One affected entity, APS, has State Estimator and RTCA capability, but neither tool is operational. As a result, APS has limited capability to monitor and operate its system to withstand potential real-time contingencies. Instead of using RTCA, APS relies on a set of previously studied contingencies and pre-determined plans to mitigate them. These studies are included in a manual that is created annually and usually updated several times a year.[78] By relying on pre-determined studies, APS cannot account and prepare for all potential contingency scenarios in real time. RTCA would provide APS with a more realistic analysis of its next potential contingency because the RTCA analysis is based on real-time conditions, as measured by State Estimator. Without RTCA, APS operators are not fully prepared to identify and plan for the next most critical contingency on its system.

RTCA would have allowed APS operators to study the impact of the loss of its H-NG. Although APS could have studied this contingency in its manual and seasonal studies, it could not have studied it *based on real-time operating conditions* that only State Estimator can provide. For example, APS's manual and seasonal studies did not study the loss of H-NG together with the multiple generator outages that existed on the day of the event.[79] As a result, APS was unprepared for the actual consequences of losing H-NG on September 8, 2011, including overloads on IID's 92 kV system and potential difficulty reclosing H-NG due to large phase angle differences.[80]

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[77] Since the event, IID has initiated changes to its RTCA program. First, it is working with a vendor to install an audible alarm feature. Second, IID has instructed its operators to constantly leave the RTCA result display screen on, rather than periodically calling it up.

[78] APS can also ask WECC RC or an APS engineer for a current-day study, but it usually relies on its manual for operations. APS also relies on WECC RC to notify it of any major post-contingency issues detected by WECC RC's RTCA results, but WECC RC might not consistently and promptly notify individual TOPs of all major issues.

[79] APS has indicated that it has had difficulty obtaining generator outage information from other BAs due to market and/or tariff concerns.

[80] Prior to the event, APS had been working with a vendor to build its RTCA capability and, since the event; it has accelerated its efforts to make RTCA operational.

### Finding 13 Reliance on Post-Contingency Mitigation Plans:

- **One affected TOP operated in an unsecured N-1 state on September 8, 2011, when it relied on post-contingency mitigation plans for its internal contingencies and subsequent overload and tripping, while assuming there would be sufficient time to mitigate the contingencies. Post-contingency mitigation plans are not viable under all circumstances, such as when equipment trips on overload relay protection that prevents operators from taking timely control actions. If this TOP had used pre-contingency measures on September 8th, such as dispatching additional generation, to mitigate first contingency emergency overloads for its internal contingencies, the cascading outages that were triggered by the loss of H-NG might have been avoided with the prevailing system conditions on September 8, 2011.**

### Recommendation 13:

- **TOPs should review existing operating processes and procedures to ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions, including control actions, to return the system to a secure N-1 state as soon as possible but no longer than 30 minutes following a single contingency. As part of this review, TOPs should consider the effect of relays that automatically isolate facilities without providing operators sufficient time to take mitigating measures.**

Before September 8, 2011, IID consistently relied on post-contingency mitigation plans, rather than proactively responding on a pre-contingency basis, for RTCA results showing that the N-1 loss of one CV transformer would result in overloading on the second CV transformer. Post-contingency plans can work to prevent a second contingency as long as operators have sufficient time to take mitigating actions. Post-contingency mitigation is not an appropriate choice for the CV transformers, which are set to trip by overload protection relays without allowing operators enough time to take mitigating actions. Specifically, the transformers' overload protection scheme is set with a thin margin between the emergency rating and the relay trip point. The normal rating of the transformers is 150 MVA, the emergency rating is 165 MVA, and the relay trip point is set at 190.5 MVA, or 127% of the normal rating. Thus, when the transformers reach their emergency rating, operators may have the mistaken belief that they have sufficient time to take mitigating actions, when, in fact, the operators will have very little time before the transformers will trip offline, because they will soon reach the relay trip setting. As shown below, pre-contingency mitigation measures are necessary when operators are faced with settings that leave such little margin between the emergency rating and overload trip point.

On multiple days during the summer of 2011, IID's RTCA results showed that an N-1 contingency tripping of one of the CV transformers would result in overloading on

the second transformer. IID continued to operate in this state on multiple days without taking any pre-contingency mitigating actions. For example, IID did not dispatch additional generation on a pre-contingency basis to control the loading on one CV transformer to prevent overloading on the second CV transformer. There were potentially severe consequences of not taking pre-contingency actions. Specifically, IID's next-day study for September 8th detailed that the loss of both CV transformers would overload: (1) IID's Ramon transformer to its trip point; and (2) the S Line, which, in turn, would cause the S Line RAS to trip generation in Mexico that supplies power to the Imperial Valley substation. In short, on multiple days in summer 2011, IID's RTCA results showed that the loss of one CV transformer would overload the second transformer, and IID's next-day study revealed the cascading outages that would stem from the loss of both transformers. Yet, IID did not institute pre-contingency mitigating measures, such as dispatching additional generation.

Instead, IID relied on post-contingency plans. On most days in summer 2011, the level of overloading on the CV transformers gave IID just enough time to successfully use a post-contingency mitigation plan to start generation after the loss of the first transformer to avoid the loss of the second transformer. However, on at least two days observed by the inquiry, a post-contingency plan would not allow the operator enough time to implement necessary procedures to mitigate the problem. On those two days, the loading on both CV transformers was high enough that only pre-contingency mitigation measures could have prevented the loss of the second transformer upon the loss of the first. On the first of those two days, IID was simply fortunate that the N-1 contingency loss of the first transformer never occurred. The second of the two days was September 8, 2011.

Forty-four minutes prior to the loss of H-NG, IID's RTCA results showed that the N-1 contingency loss of the first CV transformer would result in overloading of the second transformer to approximately 139% of its normal rating—leading to the loss of the transformer by relay action. If IID had taken action at this pre-contingency stage, IID might have been able to avoid the loss of both transformers.[81] After H-NG tripped, the relays took less than 40 seconds to trip both CV transformers. Operators had no time to mitigate the overloads before the transformers were removed from service.

[81] The inquiry understands that the IID operator did not see these RTCA results and, thus, would not have known of the need for pre-contingency mitigating measures. There is no indication, however, that IID would have used pre-contingency measures regardless of the results. IID consistently relied on post-contingency measures.

### Finding 14 WECC RC Staffing Concerns:

- **WECC RC staffs a total of four operators at any one time to meet the functional requirements of an RC, including continuous monitoring, conducting studies, and giving directives. The September 8th event raises concerns that WECC RC's staffing is not adequate to respond to emergency conditions.**

### Recommendation 14:

- **WECC RC should evaluate the effectiveness of its staffing level, training and tools. Based on the results of this evaluation, it should determine what actions are necessary to perform its functions appropriately as the RC and address any identified deficiencies.**

WECC RC performs its reliability coordination functions through two offices. Although each office is capable of monitoring the entire Interconnection, during normal operations the offices have primary responsibility for monitoring different parts of the Western Interconnection. WECC RC's Vancouver, Washington, office is primarily responsible for monitoring the Pacific Northwest (excluding PacifiCorp East), California, and CFE's territory in Mexico. WECC RC's Loveland, Colorado, office is primarily responsible for monitoring the Desert Southwest area, Rocky Mountain area, PacifiCorp's East area, Sierra Pacific Power Company's area, IID's area, and the Los Angeles intermountain area. Each office staffs two on-shift operators at all times. Each center dedicates an operator to the real-time desk (real-time operator) and the other operator to the study desk (study desk operator).

The real-time operator's primary responsibilities include monitoring limits and operating parameters, identifying exceedances, evaluating mitigation plans, and directing corrective actions. The study desk operator's primary responsibilities include monitoring expected post-contingency conditions to identify potential exceedances, evaluating actions being taken, and directing corrective action as necessary. The study desk operator also reviews WECC RC's next-day study for accuracy, conducts real-time studies to evaluate system conditions, and monitors EMS applications, such as RTCA, to identify any performance issues and request corrective actions, as necessary. The real-time operator and study desk operator also have some joint responsibilities, including reporting events that impact the BPS, identifying events or system conditions that require notification to adjacent RCs, and monitoring and testing primary and backup internal communication systems. Through these responsibilities, WECC RC is responsible for the reliable operation of the BPS in the WECC footprint, and it has the ultimate authority to prevent or mitigate emergency operating situations in both next-day and real-time timeframes.

In addition, WECC RC is responsible for providing information to the entities in its footprint, including the 53 TOPs and 37 BAs. Some of this information is provided over the telephone. During the event, in addition to performing the many RC functions they are responsible for performing, the RC operators had to answer phone calls providing or seeking information on the disturbance.

Given WECC RC's responsibility and authority, four total operators—two in each regional office—might not be sufficient to effectively perform its function, particularly during emergency conditions. Several examples from the September 8th event highlight this concern.

First, after the loss of H-NG, many alarms began sounding in WECC RC's control rooms, as voltage dropped and facilities overloaded. With so many alarms sounding in an emergency situation, the real-time operator had a difficult time prioritizing which alarms to monitor. WECC RC has eight unique categories, or "buckets," of alarms within its EMS applications, grouped according to importance. Buckets 1 and 2 contain the highest priority alarms. Bucket 1 includes all 500 and 345 kV circuit breaker status changes, frequency and Path violations, status of generators greater than 50 MW and associated circuit breakers, and critical bus voltages. Bucket 2 includes all 220/230 kV circuit breaker status changes and automatic voltage regulator status.[82] Buckets 3 through 8 include lesser priority items, such as RAS status changes, non-critical bus voltages, and circuit breaker status changes below 220 kV. Operators receive audible alarms for buckets 1 and 2 and typically leave bucket 1's display on the screen constantly and use one other screen to display all other buckets. It is a constant process to continually monitor the alarms, even during normal operating conditions, and it might not be possible for one real-time operator to keep track of and prioritize multiple alarms sounding at once. Also, both operators had numerous phone calls to field from entities throughout the affected areas, reporting and requesting information. Overburdening the real-time operator in this way could undermine his or her ability to perform the critical functions of monitoring system conditions and directing necessary corrective actions. Accordingly, WECC RC should consider whether additional operators are necessary to adequately perform these functions.

A second indication that the current RC staffing levels might not be sufficient came during the September 8th event when the study desk operator had to abandon his duties in order to provide support to the real-time operator by fielding phone calls and

[82] The CV 230/92 kV transformers are included in bucket 2.

monitoring conditions. On this day, the RC operators were able to call for an engineer to conduct some studies. Because the September 8th event occurred during the afternoon, an engineer was available. Finding an engineer to substitute for the study desk operator may not always be so easy. Late at night and early in the morning, no engineers are on duty. That the study desk operator needed to leave his responsibilities to support the real-time operator may indicate that one real-time operator and one study desk operator per office might not be sufficient to fulfill WECC's reliability coordination functions.

Alternatively, additional training and enhanced tools may enable an entity to accomplish more with the same number of personnel. While the inquiry observed a sampling of WECC RC's tools to be adequate during its site visit, WECC RC is in the best position to identify the combination of additional staff, enhanced tools, or training that best addresses the concerns identified by this report.

### Finding 15 Failure to Notify WECC RC and Neighboring TOPs Upon Losing RTCA:

- **On September 8, 2011, at least one affected TOP lost the ability to conduct RTCA more than 30 minutes prior to and throughout the course of the event due to the failure of its State Estimator to converge. The entity did not notify WECC RC or any of its neighboring TOPs, preventing this entity from regaining situational awareness.**

### Recommendation 15:

- **TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities.**

When entities temporarily lose their RTCA capability due to technical issues, they become blind to the next most severe contingency on their system, and they do not know what pre-contingency measures might be necessary. Thus, when they lose RTCA, they must take immediate action to try to regain their situational awareness. For example, after losing RTCA an entity should contact WECC RC, so the RC can monitor the entity's system and inform it of any significant issues. In such instances, the RC should also notify neighboring entities of any major contingencies that could impact their systems.

Between 13:59 and the start of the event on September 8, 2011, WALC lost its RTCA when its State Estimator stopped solving.[83] As a result, WALC lost its ability to identify and study post-contingency violations and to take pre-contingency mitigating measures, as necessary. When it lost its RTCA, WALC should have contacted WECC RC and asked it to monitor WALC's area. WECC RC could have then notified WALC

[83] By not solving, or converging, the State Estimator stopped providing estimated values for the system.

regarding any significant problems and could have also contacted WALC's neighbors if it learned of any SOLs in WALC that were impacting the neighbors' systems.[84] Prior to the event on September 8, 2011, WALC experienced several post-contingency SOL violations, but, without its RTCA capability, remained unaware of them. WECC RC's RTCA results showed these violations. WALC, however, did not notify WECC RC when it lost RTCA and, thus, WECC RC was unaware that it should notify WALC of the violations. An entity should never be operating in an unknown state, as WALC was when it lacked functional RTCA and State Estimator, and did not ask any other entity to assist it with situational awareness.

### Finding 16 Discrepancies Between RTCA and Planning Models:

- **WECC's model used by TOPs to conduct RTCA studies is not consistent with WECC's planning model and produces conflicting solutions.**

### Recommendation 16:

- **WECC should ensure consistencies in model parameters between its planning model and its RTCA model and should review all model parameters on a consistent basis to make sure discrepancies do not occur.**

The usefulness of RTCA study results and other real-time studies depend on the models used in the studies. Inaccurate models jeopardize the accuracy of studies, as well as entities' ability to respond appropriately to potential contingencies identified by the studies. The inquiry's simulation of the September 8th event discovered that a discrepancy exists between WECC RC's model used to conduct RTCA studies and the model used for WECC's planning studies. Specifically, the impedance of IID's CV transformers differed by a factor of two between the WECC models. WECC's planning model has an impedance of 0.1 per unit, while WECC RC's RTCA model has an impedance of 0.05 per unit. This difference resulted in an error of approximately 16% in the RTCA model compared to the planning model with respect to loading on the CV transformers.

Although the inquiry did not perform a comprehensive comparison of all parameters in WECC's various models, this discrepancy between the RTCA and planning models on such important facilities calls into question the validity of other parameters in WECC's models.

[84] While not at issue in this event, the RC should also notify TOPs if it loses its RTCA, so that TOPs know that the RC is not able to observe their systems.

# I. System Analysis

## Consideration of BES Equipment

- **Background**

The BES is generally defined as all facilities operating at voltages above 100 kV, although certain sub-100 kV facilities with a significant impact on the BPS may be considered a part of the BES. Each RE currently determines its specific procedure for determining what is or is not BES. If a facility is not considered BES, relevant TOPs, BAs, and RCs may not study and model the impact of that facility.

**Finding 17 Impact of Sub-100 kV Facilities on BPS Reliability:**

- **WECC RC and affected TOPs and BAs do not consistently recognize the adverse impact sub-100 kV facilities can have on BPS reliability. As a result, sub-100 kV facilities might not be designated as part of the BES, which can leave entities unable to address the reliability impact they can have in the planning and operations time horizons. If, prior to September 8, 2011, certain sub-100 kV facilities had been designated as part of the BES and, as a result, were incorporated into the TOPs' and RC's planning and operations studies, or otherwise had been incorporated into these studies, cascading outages may have been avoided on the day of the event.**

**Recommendation 17:**

- **WECC, as the RE, should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and actively monitored and alarmed in RTCA systems.**

WECC RC, as well as TOPs and BAs impacted by the event, did not consider IID's 92 kV network and facilities (including the CV and Ramon transformers) as BES elements. IID did not reconsider whether the CV and Ramon transformers should be studied like BES facilities even after a draft study sponsored by CFE (and shared with IID) suggested the existence of a through-flow issue between the 500 kV substations at Devers and Imperial Valley, adversely impacting IID's 92 kV network (including the CV and Ramon transformers) during contingencies on BPS systems, including H-NG.[85] Because the Reliability Standards apply to BES facilities, if the CV transformers had been considered BES facilities, IID would have been required to study the impact they could

[85] *See* CFE's Path 45 Increase Rating Phase 2 Study Report, January 12, 2011, at 19.

have on BPS reliability.[86] Also, WECC RC and the affected TOPs would likely have included the facilities in their studies and been aware of the impact the loss of H-NG would have on IID's 92 kV system, as well as the impact various trips within IID's 92 kV system would have on the rest of the BPS. The inquiry determined that, during the event, approximately 12% (168 MW) of the original flow on H-NG was transferred through IID's 92 kV system, making the 92 kV system part of a bulk power path as well as a significant looped transmission facility. The cascading outages that resulted from the loss of H-NG demonstrated the significant potential for IID's 92 kV system, including the CV transformers, to impact BPS reliability.

## IROL Derivations

### Background

In order to ensure the reliable operation of the BPS, entities are required to identify and plan for IROLs, which are SOLs that, if violated, can cause instability, uncontrolled separation, and cascading outages. Once an IROL is identified, system operators are then required to create plans to mitigate the impact of exceeding such a limit to maintain system reliability.

**Finding 18 Failure to Establish Valid SOLs and Identify IROLs:**

- **The cascading nature of the event that led to uncontrolled separation of San Diego, IID, Yuma, and CFE indicates that an IROL was violated on September 8, 2011, even though WECC RC did not recognize any IROLs in existence on that day. In addition, the established SOL of 2,200 MW on Path 44 and 1,800 MW on H-NG are invalid for the present infrastructure, as demonstrated by the event.**

**Recommendation 18.1:**

- **WECC RC should recognize that IROLs do exist on its system and, thus, should study IROLs in the day-ahead timeframe and monitor potential IROL exceedances in real-time.**

[86] *See, e.g.*, NERC Reliability Standard TOP-002-2b R11 (TOPs "shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs").

### Recommendation 18.2:

- **WECC RC should work with TOPs to consider whether any SOLs in the Western Interconnection constitute IROLs. As part of this effort, WECC RC should: (1) work with affected TOPs to consider whether Path 44 and H-NG should be recognized as IROLs; and (2) validate existing SOLs, and ensure that they take into account all transmission and generation facilities and protection systems that impact BPS reliability.**

The NERC Glossary defines an IROL as an SOL that, if violated, could expose a widespread area of the BPS to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the BPS. Each IROL is associated with a maximum time limit (Tv) that the IROL can be exceeded before the risk to the Interconnection or another RC area becomes greater than acceptable. The time limit can vary, but any IROL's Tv must be less than or equal to 30 minutes.[87]

For this event, the loss of H-NG should have been associated with an IROL with a Tv for this N-1 contingency of essentially 0 minutes, because the cascading from the loss of H-NG began within seconds. However, neither WECC RC nor any of the affected entities have previously identified this IROL. The WECC region historically has maintained an operating philosophy of not recognizing IROLs.[88] Instead, entities in the WECC region believe that as long as they operate within the conditions they have studied, they will not face the risk of IROLs and will not need to calculate IROLs. The September 8th event undermines this philosophy.

Prior to the event, the WECC system was supplying loads in the various balancing authority areas in the range of 85-95% of their recorded peak loads. The power flows on all the Paths in the WECC region were below their maximum ratings and voltages were within acceptable levels. In particular, the two major transmission corridors into the blackout area, namely Path 44 and H-NG, were loaded respectively to 1,302 MW and

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[87] As defined by the NERC Glossary of Terms, an IROL's Tv is "[t]he maximum time that an [IROL] can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each [IROL's] Tv shall be less than or equal to 30 minutes." NERC Glossary of Terms, February 8, 2012, at 26.

[88] As described by WECC in a February 16, 2012 Webinar on its SOL Methodology revision, "***The WECC operating philosophy is to operate only in conditions that have been studied. Therefore, under these normal operating conditions, there are never IROL conditions (only SOLs).*** An IROL condition may be created by the occurrence of one or more unanticipated contingencies. When this occurs, under WECC Reliability Standards, bulk electric system operators are required to resolve the IROL condition within 20 minutes (stability) or 30 minutes (thermal)." http://www.wecc.biz/awareness/Reliability/Documents /SOL Methodology Presentation 02.16.2012.pdf (emphasis in original).

1,372 MW. Compared to their maximum SOL ratings of 2,200 MW and 1,800 MW, these loadings represent 59% and 78% of their maximum ratings—well within current limits. Path 44 and H-NG ratings of 2,200 MW and 1,800 MW may be invalid for the present infrastructure because cascading outages due to a single contingency occurred at loadings well below the SOL ratings.

During the 11-minute disturbance, the single contingency of the sudden loss of H-NG resulted in a series of cascading outages, with multiple elements exceeding their applicable ratings and leading to a widespread blackout of the area.

Accordingly, WECC RC should lead all relevant TOPs in the blackout area to study and report on the appropriateness of identifying Path 44 and H-NG as IROL paths. WECC RC should similarly assess transfer Paths outside this blackout area to ensure that there are no other similar reliability issues in the Western Interconnection. Existing operating processes and procedures should be reviewed to ensure corrective control capabilities are provided to system operators to enable them to return the system to a secure N-1 state as soon as possible, but no longer than 30 minutes following a single contingency.

WECC RC has a proposed new SOL Methodology document (current effective date of June 4, 2012), which acknowledges the need to establish IROLs, and the RC's responsibility to monitor IROLs.[89] It recognizes that "Stability SOLs may qualify as IROLs depending on the potential consequences of exceeding the limit and the impact on BES reliability. WECC RC makes this determination by collaborating with TOPs to understand the nature of the stability SOL, understanding the conditions that result in the establishment of the stability SOL, and determining the BES impacts of exceeding the stability SOL."[90] WECC RC also has a proposed multi-step process for determining whether thermal or voltage SOLs are IROLs. In general, WECC RC will look at whether potential IROLs cause "Widespread Adverse System Impacts," or "potential cascading." "Widespread Adverse System Impacts" is defined as "loading of three or more additional BES Facilities beyond 125% of their applicable emergency thermal Facility Rating, or [t]hree or more additional BES Facilities with bus voltages experiencing voltages less than 90%."91 "Potential cascading" is defined as "when studies indicate that a

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[89] *See* WECC System Operating Limits Methodology for the Operations Horizon, Version 6.1, *available at* http://www.wecc.biz/awareness/Reliability/ WECC RC Operating Procedures/WECC FAC 011-EFFECTIVE DATE 6-4-2012 SOL Methodology for the Operations Horizon.pdf.

[90] *Id.* at 5.

[91] *Id.* at 6.

contingency results in severe loading on a Facility, triggering a chain reaction of Facility disconnection by relay action, equipment failure, or forced immediate manual disconnection of the Facility (for example, public safety concerns, or no time for the operator to implement mitigation actions)."[92]

## Impact of Protection Systems on Event

### Protection System Coordination

When an abnormal system condition is detected on the BPS, relay protection systems operate to isolate the problem while causing minimum disturbance to the power system. This requires the relay to be selective in determining which elements to interrupt. The only method of obtaining this selectivity is to perform coordination studies. The inquiry discovered that two TOs did not properly coordinate a protection system and a third TO implemented a protection scheme without performing any coordination studies at all. This lack of coordination of protection systems resulted in circuits unnecessarily being interrupted, which had an undesirable effect on BPS reliability during the September 8th event.

**Finding 19 Lack of Coordination of the S Line RAS:**

- **Several TOs and TOPs did not properly coordinate a RAS by: (1) not performing coordination studies with the overload protection schemes on the facilities that the S Line RAS is designed to protect; and (2) not assessing the impact of setting relays to trip generation sources and a 230 kV transmission tie line prior to the operation of a single 161/92 kV transformer's overload protection. As a result, BES facilities were isolated in excess of those needed to maintain reliability, with adverse impact on BPS reliability.**

**Recommendation 19:**

- **The TOs and TOPs responsible for design and coordination of the S Line RAS should revisit its design basis and protection settings to ensure coordination with other protection systems in order to prevent adverse impact to the BPS, premature operation, and excessive isolation of facilities. TOs and TOPs should share any changes to the S Line RAS with TPs and PCs so that they can accurately reflect the S Line RAS when planning.**

Operation of the S Line RAS isolates facilities beyond what is necessary to ensure reliability. The S Line RAS is a directional overload scheme, located at the Imperial Valley substation, which is jointly owned by SDG&E and IID. The S Line RAS was originally implemented to protect the sole 230/161 kV transformer at El Centro from

[92] *Id.*

overloads due to increased flow on the S Line.[93] At the time, this was the only transfer point from the 230 kV line to the 161 kV system, and subsequently the 92 kV system, in IID's southern area. After implementing this RAS, IID has since installed a 230/92 kV transformer at El Centro, providing another path from the 230 kV system to the lower voltage networks.

IID's current intention for the S Line RAS is to reduce loading on the S Line by tripping generation and, if insufficient to reduce flow, tripping the S Line at Imperial Valley Substation before transformer overload protection operates to trip the 161/92 kV transformer at El Centro. Tripping the S Line before allowing the El Centro 161/92 kV transformer's overload protection to take action effectively results in the removal of the 230 kV source at the El Centro substation, which normally feeds a 230/92 kV transformer and a 230/161 kV transformer. Thus, the design of the S Line RAS intentionally isolates networked BES facilities to mitigate an overload on a non-BES facility (El Centro 161/92 kV transformer) to support reliability of the local system. While this action alone does not constitute miscoordination, proper coordination of a RAS should take into account, through system studies, the potential impact on BPS reliability, including potential interaction with other RASs and protection systems.

During the September 8th event, the S Line RAS operated as designed, in that it tripped when it reached the settings that IID had prescribed. However, if one considers the purpose of the S Line RAS, which was to protect the El Centro transformer from overloads, the S Line RAS operated long before it was needed. At the time that the S Line RAS operated, the El Centro 161/92 transformer was only loaded to 38% of its normal rating, and its overload trip point is 178% of its normal rating. Thus, the El Centro 161/92 transformer could have carried at least four times as much load before the transformer's overload protection system would have operated. Even though the El Centro transformer that the S Line RAS was designed to protect was nowhere near overloading, the S Line RAS tripped important generation and a 230 kV line. This calls into question the coordination of the S Line RAS with the transformer overload protection systems at El Centro.

IID provided SDG&E with the S Line RAS settings to implement. IID did not perform any studies to coordinate the S Line RAS with IID's protection systems. SDG&E did some studies to verify that the RAS coordinated with SDG&E's protection systems. There is no indication that the S Line RAS was coordinated with IID's transformer overload protection at the El Centro station at which the S Line terminates. At a

[93] The S Line RAS also serves as secondary protection for other IID facilities if a RAS on the Imperial Valley to Miguel 500 kV line fails to operate.

minimum, IID, SDG&E and CAISO (as the TOP for SDG&E) should work together to ensure the proper coordination of the S Line RAS.

To make matters worse, during the September 8th event, San Diego was relying on generation at Imperial Valley from the south when the S Line RAS tripped that generation. Loss of the Imperial Valley generation caused San Diego to pull even more power from the north, increasing the loading on Path 44 and causing the SONGS separation scheme to further exceed its trip point. If not tripped by the S Line RAS, generation at Imperial Valley could have helped SDG&E survive after the operation of the SONGS separation scheme. The inquiry's simulation showed that, had the S Line RAS tripped only the S Line without tripping the generation, the SONGS separation scheme would not have operated, and only IID would have lost power.[94]

### Finding 20 Lack of Coordination of the SONGS Separation Scheme:

- **SCE did not coordinate the SONGS separation scheme with other protection systems, including protection and turbine control systems on the two SONGS generators. As a result, SCE did not realize that Units 2 and 3 at SONGS would trip after operation of the separation scheme.**

### Recommendation 20:

- **SCE should ensure that the SONGS separation scheme is coordinated with other protection schemes, such as the generation protection and turbine control systems on the units at SONGS and UFLS schemes.**

SCE, the TO and TOP of the SONGS separation scheme, did not perform any protection system coordination studies for the separation scheme it implemented at SONGS. The scheme is intended to isolate five 230 kV lines simultaneously if its preset value is exceeded for a sustained period. If SCE had coordinated the separation scheme with other protection and generation control systems at SONGS, it may have recognized the potential for the operation of the SONGS separation scheme to cause the SONGS generators to trip. Coordination in this context requires system studies to assess the impact of operation of the RAS on the power system, including potential interaction with other RASs and protection systems, such as UFLS schemes.

In addition to the consequences at SONGS itself, the lack of coordination of the systems means that, when the scheme operates, the system enters an unknown state. During the event, the operation of the protection scheme significantly contributed to the

[94] *See* footnote 53.

blackout of SDG&E, CFE, and Yuma—an effect neither coordinated nor adequately studied prior to the event. The inquiry's simulation indicates that SDG&E, CFE and, Yuma would not have been blacked out if the SONGS separation scheme had not operated, with limited impact to the rest of the Western Interconnection.

### Finding 21 Effect of SONGS Separation Scheme on SONGS Units:

- **The SONGS units tripped due to their turbine control systems detecting unacceptable acceleration following operation of the SONGS separation scheme.**

### Recommendation 21:

- **GOs and GOPs should evaluate the sensitivity of the acceleration control functions in turbine control systems to verify that transient perturbations or fault conditions in the transmission system resulting in unit acceleration will not result in unit trip without allowing time for protective devices to clear the fault on the transmission system.**

When the SONGS separation scheme operated, turbines at SONGS began to accelerate in excess of their control system setting causing both units to trip offline. The tripping of the SONGS units in this manner raises questions about the sensitivity of the turbine control system's settings. The units are expected to withstand severe faults on the transmission system and allow the transmission protection systems to operate without the generators tripping offline. The coordination required for this protection is not a traditional relay-to-relay coordination; rather, the setting for the acceleration function should be coordinated with capabilities of the turbine and with the system response anticipated following operation of transmission protection systems for faults under various system conditions. The setting should also be coordinated with the system response following operation of the SONGS separation scheme. Had the turbine control system acceleration function been coordinated in this manner, the trip of the units may have been avoided.

## Protection System Studies

### Finding 22 Lack of Review and Studying Impact of SPSs:

- **Although WECC equates SPSs with RASs, prior to October 1, 2011, WECC's definition of RAS excluded many protection systems that would be included within NERC's definition of SPS. As a result, WECC did not review and assess all NERC-defined SPSs in its region, and WECC's TOPs did not perform the required review and assessment of all NERC-defined SPSs in their areas.**

### Recommendation 22:

- **WECC RE, along with TOs, GOs, and Distribution Providers (DPs), should periodically review the purpose and impact of RASs, including Safety Nets and Local Area Protection Schemes, to ensure they are properly classified, are still necessary, serve their intended purposes, are coordinated properly with other protection systems, and do not have unintended consequences on reliability. WECC RE and the appropriate TOPs should promptly conduct these reviews for the SONGS separation scheme and the S Line RAS.**

The NERC definition of an SPS concludes with "Also called Remedial Action Scheme."[95] This implies that all SPSs are RASs and vice versa, but prior to October 1, 2011, the WECC region did not equate SPSs with RASs.[96] WECC created four classifications of protection systems that fall under the NERC definition of SPS, and, instead of including all of these classifications in the RAS definition, WECC only identified a subset of those protection systems as RASs. Safety Nets, Wide Area Protection Systems (WAPS), and Local Area Protection Systems (LAPS) were excluded from the WECC definition of a RAS even though they are SPSs as defined by NERC.

For example, SCE did not study the impact of the SONGS separation scheme on BPS reliability because it believed, by classifying this scheme as a Safety Net, that it was not required to be studied. SCE also did not submit the separation scheme to WECC for review by the Remedial Action Scheme Reliability Subcommittee (RASRS). The inquiry determined that the SONGS separation scheme is indeed an SPS/RAS as defined by NERC, because it altered the BPS configuration by separating Path 44 and redistributing generation in the absence of any faulted equipment. WECC, SDG&E, and SCE did not study the impact that the SONGS separation scheme could have on BPS reliability and, thus, were unaware of its severe impact on the BPS when the scheme operated: blacking out SDG&E and CFE and leading to the loss of the SONGS generators.

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95 NERC Glossary of Terms, February 8, 2012, at 46.

96 On October 1, 2011, WECC revised its definition of RAS to include Safety Nets and Local Area Protection Schemes.

Another protection system that did not get the necessary scrutiny due to WECC's narrow definition of RAS was the S Line RAS. The S Line is a 230 kV transmission line that serves as a major tie between SDG&E & IID. It runs from IID's and SDG&E's jointly owned Imperial Valley station on one end to IID's El Centro station on the other. The S Line RAS, as IID and SDG&E called it, was classified as a LAPS by WECC, which called it the "S Line Scheme." Thus, the RAS received no periodic assessments. Like the SONGS scheme, the S Line RAS appears to be a SPS/RAS as defined by NERC, because it is an automatic protection system that took action other than isolating a faulted facility by tripping generation in Mexico for loading on a tie line between SDG&E and IID.

The S Line RAS was implemented for two reasons: (1) to protect IID's system from overload during an N-2 event at SDG&E's Miguel substation; and (2) to protect IID's lone 230/161kV transformer at El Centro from overloads due to generation additions at Imperial Valley substation. The inquiry questions whether the scheme is still necessary, as both of the concerns that originally triggered installation of the S Line RAS have been mitigated. IID added a new transformer bank at El Centro, mitigating the concern for overloads on the 230/161kV transformer. Also, reconfigurations at Miguel along with the modifications to a RAS at Miguel have mitigated the concern of adverse effects on IID's system as a result of an N-2 event at Miguel. Since LAPSs are not periodically reviewed, the arguably outdated S Line RAS was still active during the September 8th event**,** and its operation contributed to IID's uncontrolled separation and the operation of the SONGS separation scheme by tripping over 400 MW of generation before the S Line itself tripped. At a minimum, SDG&E, IID and CAISO should participate in the review of the S Line RAS.

The SPSs that operated during the event suggest that WECC's previous exclusion of certain NERC-defined SPSs from WECC's RAS definition had an adverse impact on BPS reliability.

### Finding 23 Effect of Inadvertent Operation of SONGS Separation Scheme on BPS Reliability:

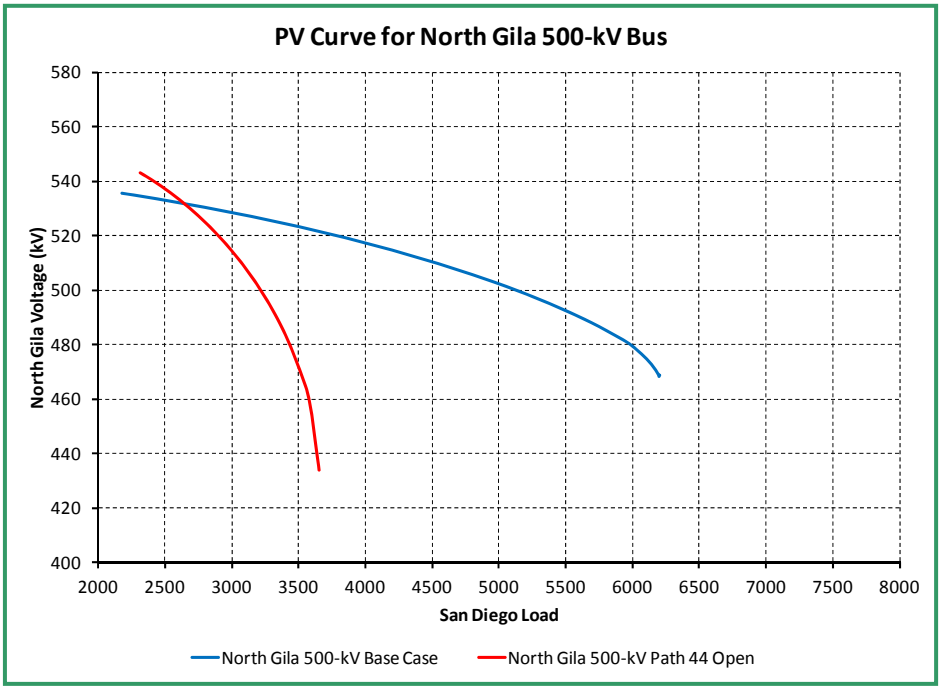
- **The inquiry's simulation of the event shows that the inadvertent operation of the SONGS separation scheme under normal system operations could lead to a voltage collapse and blackout in the SDG&E areas under certain high load conditions.**

### Recommendation 23:

- **CAISO and SCE should promptly verify that the inadvertent operation of the SONGS separation scheme does not pose an unacceptable risk to BPS reliability. Until this verification can be completed, they should consider all actions to minimize this risk, up to and including temporarily removing the SONGS separation scheme from service.**

The inquiry conducted a simulation to evaluate what would happen if the SONGS separation scheme inadvertently operated during normal system operations (e.g., in the absence of any outages, overloads, or SOL violations). Based on this simulation, the inquiry determined that under certain high load conditions, the operation of the scheme could result in voltage collapse and a blackout in SDG&E's and CFE's territories. The inquiry conducted a voltage stability study using a Power-Voltage (P-V) curve to estimate the amount of SDG&E load that could reliably be supplied after an inadvertent operation of the SONGS separation scheme. The P-V curve below in ***Figure* 16** demonstrates that such operation would lead to a voltage collapse and a blackout in the SDG&E and CFE territories under certain high load conditions.

**Figure 16: PV Curve for North Gila 500 kV Bus**




Specifically, the system is most likely to collapse when the SDG&E load exceeds 3,500 MW. In 2010, SDG&E's load exceeded this amount for 851 hours,[97] meaning that

[97] SDG&E Annual Electric Balancing Authority Area and Planning, FERC Form No. 714 (2010).

the system was exposed to a potential blackout for approximately 10% of the year. This shows the potential risk to BPS reliability during normal system operations as a result of the inadvertent operation of the SONGS separation scheme. Accordingly, given the lack of studies done on the scheme, the inquiry recommends that the inadvertent operation of the SONGS separation scheme be reviewed promptly to ensure it does not pose an unacceptable risk to BPS reliability. Until this verification can be completed, CAISO and SCE should consider all actions needed to minimize this risk, up to and including temporarily removing the scheme from service.

Moreover, if SCE and CAISO were to decide to temporarily remove the scheme from the service, the inquiry does not believe that BPS reliability would be jeopardized. Indeed, inquiry simulations conducted for the day of the event show that if the scheme had not operated, the system, with the exception of collapses in the IID and Yuma areas, would have stabilized with minor overloads in the area around SONGS, acceptable voltages in the SDG&E area, and sufficient reactive margins in the critical portion of SCE's system.

### Finding 24 Not Recognizing Relay Settings When Establishing SOLs:

- **An affected TO did not properly establish the SOL for two transformers, as the SOL did not recognize that the most limiting elements (protective relays) were set to trip below the established emergency rating. As a result, the transformers tripped prior to the facilities being loaded to their emergency ratings during the restoration process, which delayed the restoration of power to the Yuma load pocket.**

### Recommendation 24:

- **TOs should reevaluate their facility ratings methodologies and implementation of the methodologies to ensure that their ratings are equal to the most limiting piece of equipment, *including relay settings*. No relay settings should be set below a facility's emergency rating. When the relay setting is determined to be the most limiting piece of equipment, consideration should be given to reviewing the setting to ensure that it does not unnecessarily restrict the transmission loadability.**

TOs are required to designate and share their facilities' SOLs. An SOL is the value that satisfies the most limiting element of a facility beyond which the system cannot operate reliably. The inquiry's relay loadability calculations show that APS failed to properly establish the SOL for two of its 500/69 kV transformers in North Gila, because the transformers' relay loadability or load limit was actually set below their emergency ratings. A facility cannot operate above its relay load limit, as operation in

excess of a load limit results in the facility being removed from service. Thus, these settings prevented the TOP from taking advantage of the short term emergency ratings identified by the transformers' SOLs. These settings resulted in difficulties restoring power to the Yuma load pocket, as operators believed they could load the transformers up to their emergency rating. Instead, the transformers tripped below the emergency rating, delaying the restoration of power to Yuma.

If the SOL derivation had considered the transformer relay load limit, the TO could have (1) provided an SOL that accurately reflected the relay load limit so the system operator could have limited the transformer loading appropriately, or (2) reviewed the relay load limit to determine whether it unnecessarily limited the transformer loadability, and if so, raised the transformer relay setting threshold above the transformer emergency rating while coordinating the setting with the transformer short-time thermal capability.

### Load-Responsive Phase Protection Systems Set Too Close to Normal or Emergency Ratings

BES facilities at a minimum are required to have normal and emergency ratings. The normal rating is a continuous rating or a rating that a facility can be operated to on a daily basis that specifies the amount of electrical loading a facility can support. The emergency rating specifies the level of electrical loading a facility can support for a finite period of time. Operating a facility beyond its normal and/or emergency rating for an extended period of time will expose certain equipment in that facility to the risk of thermal damage. In order to prevent thermal damage to facilities, some TOs implement overload protection systems that are designed to automatically isolate the facilities if operated beyond their emergency rating.

A problem arises when overload protection systems are set in close proximity to a facility's normal or emergency ratings. Setting the overload protection close to the normal or emergency ratings restricts facility loading and prevents operators from having sufficient time to take remedial action to mitigate an overload before the facility is automatically isolated by the overload protection system.[98] As the Commission stated in Order No. 733, "manual mitigation of thermal overloads is best left to system operators, who can take appropriate actions to support Reliable Operation of the Bulk-

[98] NERC Reliability Standard PRC-023-1 R1.11 provides the following guidance on setting of overload protection systems on transformers: "Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater."

Power System."[99] Protective relay settings limited transmission loadability with extremely conservative overload protection settings, resulting in cascading outages during the September 8th event. These settings resulted in facilities being automatically removed from service by relays before operators had an opportunity to take remedial action.

### Finding 25 Margin Between Overload Relay Protection Settings and Emergency Rating:

- **Some affected TOs set overload relay protection settings on transformers just above the transformers' emergency rating, resulting in facilities being automatically removed from service before TOPs have sufficient time to take control actions to mitigate the resulting overloads. One TO in particular set its transformers' overload protection schemes with such narrow margins between the emergency ratings and the relay trip settings that the protective relays tripped the transformers following an N-1 contingency.**

### Recommendation 25:

- **TOs should review their transformers' overload protection relay settings with their TOPs to ensure appropriate margins between relay settings and emergency ratings developed by TOPs. For example, TOs could consider using the settings of Reliability Standard PRC-023-1 R.1.11 even for those transformers not classified as BES. PRC-023-1 R.1.11 requires relays to be set to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater.**

Relay loadability calculations indicate that the relay settings on a number of transmission facilities limited transmission loadability to slightly above the emergency rating. For example, the relays on IID's CV transformers were set to trip at 127% of their normal rating. The parallel CV transformers were loaded to 130%, which was above their 127% overload relay trip point, immediately after the loss of H-NG. Both transformers tripped less than 40 seconds later. If the transformers' overload trip point had been in accordance with PRC-023-1 R.1.11, the trip point would not have been exceeded immediately after the loss of the H-NG, and IID operators might have had time to take actions to prevent cascading.[100]

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[99] *Transmission Relay Loadability Reliability Standard*, 130 FERC ¶ 61,221, at P 212 (2010).

[100] IID originally used conservative settings because the CV transformers are rare, expensive, load-serving transformers. IID has indicated, however, that it will increase the overload relay settings on the CV transformers to 150% of their normal rating, and will relocate an additional 230/92 kV transformer from another substation to CV.

During the September 8th event, IID was unaware that the overload relay setting for the Ramon 230/92 kV transformer had been mistakenly set at 207% of its normal rating. IID intended the Ramon transformer to have been set to trip at 120% of its normal rating. After the event, IID reduced the Ramon transformer's trip setting from 207% to 120%, making it more likely to trip during high-loading conditions or conditions similar to those that precipitated the blackout, decreasing the opportunity for its operators to take mitigating actions during such conditions. This setting actually increased the risk of future cascading outages like the one which occurred on September 8, 2011.

### Finding 26 Relay Settings and Proximity to Emergency Ratings:

- **Some TOs set relays to isolate facilities for loading conditions slightly above their thirty minute emergency ratings. As a result, several transmission lines and transformers tripped within seconds of exceeding their emergency ratings, leaving TOPs insufficient time to mitigate overloads.**

### Recommendation 26:

- **TOs should evaluate load responsive relays on transmission lines and transformers to determine if the settings can be raised to provide more time for TOPs to take manual action to mitigate overloads that are within the short-time thermal capability of the equipment instead of allowing relays to prematurely isolate the transmission lines. If the settings cannot be raised to allow more time for TOPs to take manual action, TOPs must ensure that the settings are taken into account in developing facility ratings and that automatic isolation does not result in cascading outages.**

In addition to the problematic protection settings of the CV transformers, which precipitated the cascade, the inquiry discovered that several other facilities, including a number of IID's 161 kV transmission lines and two of WALC's 161/69 kV transformers, had relay protection settings which were only slightly above those facilities' emergency ratings. These conservative settings severely limited TOPs' response time before the facilities were isolated, preventing the operators from taking effective mitigating action against the cascade. While the inquiry did not determine whether less conservative relay settings on these other facilities would have mitigated the cascade, the applied settings nevertheless do not leave operators sufficient time to take mitigating steps to prevent or ameliorate the consequences of future events.

## Angular Separation

When a transmission line trips or goes out of service, the phase angle will generally increase between its two terminal points. When angle differences become large, facilities connected to the system can lose synchronization, causing the system to

become unstable. Also, if the phase angle is too large, closing the line breaker back into service with a large angle difference may result in damage to nearby generator turbine shafts, and the resulting power swings and oscillations could lead to system instability or collapse. To enable successful reclosing, studies should be run to determine the maximum phase angle difference allowable for a line to be closed back in and safeguards be put into place to prevent reclosure with excessive phase angle difference. Should the phase angle difference exceed the established limit, generation or load must be adjusted to reduce it to the level that allows the line to be closed.

### Finding 27 Phase Angle Difference Following Loss of Transmission Line:

- **A TOP did not have tools in place to determine the phase angle difference between the two terminals of its 500 kV line after the line tripped. Yet, it informed the RC and another TOP that the line would be restored quickly, when, in fact, this could not have been accomplished.**

### Recommendation 27:

- **TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operating plans for reclosing lines with large phase angle differences. TOPs should also train operators to effectively respond to phase angle differences. These plans should be developed based on the seasonal and next-day contingency analyses that address the angular differences across opened system elements.**

The inquiry's simulation shows that after H-NG tripped, the voltage phase angle between the two terminals increased from 20 degrees to approximately 72 degrees. On the day of the event, APS's synchro-check relay was set at 60 degrees,[101] meaning APS would not have been able to reclose H-NG until it reduced the phase angle difference from 72 to 60 degrees, or changed the relay setting to allow the breaker to close. Specifically, the 60 degree setting would not have allowed APS to reclose H-NG until appropriate generation on both sides of North Gila was dispatched or load reductions in the areas west of North Gila were implemented to reduce the difference of the voltage phase angle to 60 degrees.

[101] Based on additional studies, APS has since determined the maximum settings on its synchro-check relay at North Gila to allow a maximum phase angle difference of 75 degrees to reclose a line. To add margin, APS has implemented the relay setting at 70 degrees.

Although APS operators are trained to effectively respond to phase angle differences,[102] APS currently lacks the tools necessary to determine phase angle differences following the loss of a transmission line until the line is reenergized.[103] The training, therefore, does little good if the operators cannot determine whether a phase angle difference exists in the first place. Generally, APS operators can monitor phase angles through SCADA, but in order to receive and review this data, the transmission line must be energized. After H-NG tripped, and prior to reenergizing the line, for example, APS had no way to know if the line could be reclosed within the permissive 60 degree setting of its synchro-check relay. It lacked situational awareness of the phase angle difference. Yet, APS informed WECC RC and CAISO that it believed the line could be reclosed quickly, when, in fact, this could not have been done due to the phase angle difference.[104]

To avoid a similar situation in the future, TOPs should ensure that they have adequate tools to determine phase angles after the loss of transmission lines. For example, they can install PMUs throughout their system, as APS plans to do, to increase their situational awareness of phase angles. Moreover, TOPs should ensure that their operators are trained to respond to phase angle differences by, for example, redispatching generation. In addition, TOPs should not underestimate the time required to reclose a line, particularly without first knowing the phase angle difference. Here, for example, APS likely could not have reclosed the line quickly, even had it known the phase angle difference, given system conditions on the day of the event.

Indeed, the inquiry conducted a series of power flow simulations and found that significant amounts of generation redispatch were needed to close the phase angle difference. ***Figure* 17**, on the next page, shows the relationship between the voltage phase angle of H-NG as generation is redispatched between California and Arizona. The dispatched approach adjusts the available generation nearest the Hassayampa and North Gila buses. As generation is dispatched to its maximum output in the vicinity of the two

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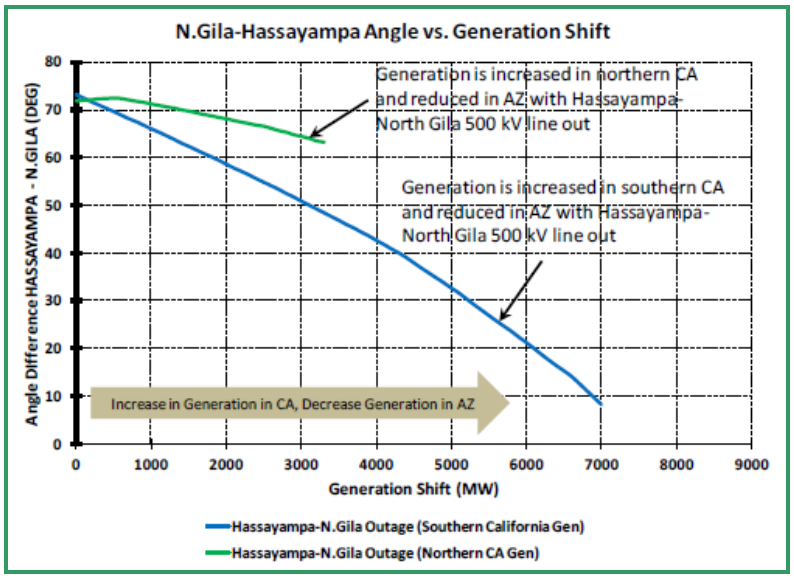
[102] APS provides its certified operators with two training classes, Power System Dynamics and Dynamics of Disturbances, both of which address power angles and their ramifications. In addition, APS provides its new operator trainees with training on power angles.

[103] APS plans to expand its use of PMUs to enable it to determine phase angle differences even without a line being energized. Through the PMU data, APS would be able to determine voltage and angle measurements on live buses in its substations, through which it could calculate phase angle differences.

[104] APS did not intentionally mislead WECC RC and CAISO with this statement. Rather, it did not expect that there would have been such a large phase angle difference, as it had not previously experienced such a difference. Moreover, APS determined that the line was not damaged and, thus, it did not believe there would be any issues closing the line.

stations, other generators farther out are adjusted to effect the change in voltage phase angles.

**Figure 17: Phase Angle of H-NG vs. Generation Shift**




The blue line in Figure 17 illustrates that with the particular conditions of the September 8th event, approximately 1,800 MW needed to be redispatched on both ends of H-NG (and close to the terminals, in Southern California and Arizona) in order to close the voltage phase angle from 72 degrees to 60 degrees (i.e., to within the permissive 60 degree setting of the synchro-check relay). The green line shows that more generation—more than twice as much—must be redispatched if units are chosen in Northern California to close the angle between Hassayampa and North Gila.

While system operators could redispatch generation from available spinning reserves or commit units in the Southern and/or Northern California area, it is questionable how quickly 1,800 MW could be dispatched.

## Appendix A: List of Acronyms Used in Report

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|---|---|
| **ACE** | Area Control Error |
| **APS** | Arizona Public Service |
| **BA** | Balancing Authority |
| **BES** | Bulk Electric System |
| **BPS** | Bulk-Power System |
| **CAISO** | California Independent System Operator, Inc. |
| **CFE** | Comisión Federal de Electricidad |
| **CV** | Coachella Valley |
| **EMS** | Energy Management System |
| **GO** | Generator Owner |
| **GOP** | Generator Operator |
| **H-NG** | APS's Hassayampa-North Gila 500 kV transmission line |
| **IEEE** | Institute of Electrical and Electronics Engineers |
| **IID** | Imperial Irrigation District |
| **IROL** | Interconnection Reliability Operating Limit |
| **kV** | Kilovolt |
| **LAPS** | Local Area Protection System |
| **MVA** | Megavolt-ampere |
| **MW** | Megawatt |
| **NERC** | North American Electric Reliability Corporation |
| **OSS** | California/Mexico Operations Study Subcommittee |
| **OTC** | Operating Transfer Capabilities |
| **OTCPC** | Operating Transfer Capability Policy Committee |
| **PC** | Planning Coordinator |
| **PMU** | Phasor Measurement Unit |
| **RAS** | Remedial Action Scheme |
| **RC** | Reliability Coordinator |
| **RE** | Regional Entity |
| **RTCA** | Real-Time Contingency Analysis |
| **SASG** | Southwest Area Study Group |
| **SCADA** | Supervisory Control and Data Acquisition |
| **SCE** | Southern California Edison |
| **SDG&E** | San Diego Gas & Electric |
| **SE** | State Estimator |
| **SOE** | Sequence of Events |
| **SOL** | System Operating Limit |
| **SONGS** | San Onofre Nuclear Generating Station |
| **SPS** | Special Protection System |

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| **SRP** | Salt River Power |
| **SWPL** | Southwest Power Link |
| **TO** | Transmission Owner |
| **TOP** | Transmission Operator |
| **TP** | Transmission Planner |
| **UFLS** | Underfrequency Load Shedding |
| **VAR** | Volt-Ampere Reactive |
| **WALC** | Western Area Power Administration – Lower Colorado |
| **WAPS** | Wide Area Protection System |
| **WECC** | Western Electricity Coordinating Council |
| **YCA** | Yuma Cogeneration Associates |

## Appendix B: Table of Findings and Recommendations

The following table provides a complete list of findings and corresponding recommendations, each of which are discussed in detail at Section IV of the report.

| NEXT-DAY PLANNING | | |
|---|---|---|
| **FINDING** | **RECOMMENDATION** | **APPLICABLE ENTITIES** |
| *Finding 1 – Failure to Conduct and Share Next-Day Studies*: Not all of the affected TOPs conduct next-day studies or share them with their neighbors and WECC RC. As a result of failing to exchange studies, on September 8, 2011 TOPs were not alerted to contingencies on neighboring systems that could impact their internal system and the need to plan for such contingencies. | *Recommendation 1*: All TOPs should conduct next-day studies and share the results with neighboring TOPs and the RC (before the next day) to ensure that all contingencies that could impact the BPS are studied. | TOPs |
| *Finding 2 – Lack of Updated External Networks in Next-Day Study Models*: When conducting next-day studies, some affected TOPs use models for external networks that are not updated to reflect next-day operating conditions external to their systems, such as generation schedules and transmission outages. As a result, these TOPs' next-day studies do not adequately predict the impact of external contingencies on their systems or internal contingencies on external systems. | *Recommendation 2*: TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and transmission outages and scheduled interchanges, which can significantly impact the operation of their systems. TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities. Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs. | TOPs, BAs, RCs |
| *Finding 3 –Sub-100 kV Facilities Not Adequately Considered in Next-Day Studies*: In conducting next-day studies, some affected TOPs focus primarily on the TOPs' internal SOLs and the need to stay within established Rated Path limits, without adequate consideration of some lower voltage facilities. As a result, these TOPs risk overlooking facilities that may become overloaded and impact the reliability of the BPS. Similarly, the RC does not study sub-100 kV facilities that impact BPS reliability unless it has | *Recommendation 3*: TOPs and RCs should ensure that their next-day studies include all internal and external facilities (including those below 100 kV) that can impact BPS reliability. | TOPs, RCs |

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| specifically been alerted to issues with such facilities by individual TOPs or the RC has otherwise identified a particular sub-100 kV facility as affecting the BPS. | | |
| *Finding 4 – Flawed Process for Estimating Scheduled Interchanges*: WECC RC's process for estimating scheduled interchanges is not adequate to ensure that such values are accurately reflected in its next-day studies. As a result, its next-day studies may not accurately predict actual power flows and contingency overloads. | *Recommendation 4*: WECC RC should improve its process for predicting interchanges in the day-ahead timeframe. | WECC RC |
| **SEASONAL PLANNING** | | |
| **FINDING** | **RECOMMENDATION** | **APPLICABLE ENTITIES** |
| *Finding 5 – Lack of Coordination in Seasonal Planning Process*: The seasonal planning process in the WECC region lacks effective coordination. Specifically, the four WECC subregions do not adequately integrate and coordinate studies across the subregions, and no single entity is responsible for ensuring a thorough seasonal planning process. Instead of conducting a full contingency analysis based on all of the subregions' studies, the subregions rely on experience and engineering judgment in choosing which contingencies to discuss. As a result, individual TOPs may not identify contingencies in one subregion that may affect TOPs in the same or another subregion. | *Recommendation 5*: WECC RE should ensure better integration and coordination of the various subregions' seasonal studies for the entire WECC system. To ensure a thorough seasonal planning process, at a minimum, WECC RE should require a full contingency analysis of the entire WECC system, using one integrated seasonal study, and should identify and eliminate gaps between subregional studies. Individual TOPs should also conduct a full contingency analysis to identify contingencies outside their own systems that can impact the reliability of the BPS within their system and should share their seasonal studies with TOPs shown to affect or be affected by their contingencies. | WECC RE, TOPs |
| *Finding 6 –External and Lower-Voltage Facilities Not Adequately Considered in Seasonal Planning Process*: Seasonal planning studies do not adequately consider all facilities that may affect BPS reliability, including external facilities and lower-voltage facilities. | *Recommendation 6*: TOPs should expand the focus of their seasonal planning to include external facilities and internal and external sub-100 kV facilities that impact BPS reliability. | TOPs |
| *Finding 7 – Failure to Study Multiple Load Levels*: TOPs do not always run their individual seasonal planning studies based on the multiple WECC base cases | *Recommendation 7*: TOPs should expand the cases on which they run their individual planning studies to include multiple base cases, as well as generation maintenance outages and dispatch scenarios during high | TOPs |

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| (heavy and light load summer, heavy and light load winter, and heavy spring), but, instead, may focus on only one load level. As a result, contingencies that occur during the shoulder seasons (or other load levels not studied) might be missed. | load shoulder periods. | |
| *Finding 8 – Not Sharing Overload Relay Trip Settings*: In the seasonal planning process, at least one TOP did not share with neighboring TOPs overload relay trip settings on transformers and transmission lines that impacted external BPS systems. | *Recommendation 8*: TOPs should include in the information they share during the seasonal planning process the overload relay trip settings on transformers and transmission lines that impact the BPS, and separately identify those that have overload trip settings below 150% of their normal rating, or below 115% of the highest emergency rating, whichever of these two values is greater. | TOPs |
| **NEAR- AND LONG-TERM PLANNING** | | |
| **FINDING** | **RECOMMENDATION** | **APPLICABLE ENTITIES** |
| *Finding 9 – Gaps in Near- and Long-Term Planning Process*: Gaps exist in WECC RE's, TPs' and PCs' processes for conducting near- and long-term planning studies, resulting in a lack of consideration for: (1) critical system conditions; (2) the impact of elements operated at less than 100 kV on BPS reliability; and (3) the interaction of protection systems. As a consequence, the affected entities did not identify during the planning process that the loss of a single 500 kV transmission line could potentially cause cascading outages. Planning studies conducted between 2006 and 2011 should have identified the critical conditions that existed on September 8th and proposed appropriate mitigation strategies. | *Recommendation 9*: WECC RE should take actions to mitigate these and any other identified gaps in the procedures for conducting near- and long-term planning studies. The September 8th event and other major events should be used to identify shortcomings when developing valid cases over the planning horizon and to identify flaws in the existing planning structure. WECC RE should then propose changes to improve the performance of planning studies on a subregional- and Interconnection-wide basis and ensure a coordinated review of TPs' and PCs' studies. TOPs, TPs and PCs should develop study cases that cover critical system conditions over the planning horizon; consider the benefits and potential adverse effects of all protection systems, including RASs, Safety Nets (such as the SONGS separation scheme), and overload protection schemes; study the interaction of RASs and Safety Nets; and consider the impact of elements operated at less than 100 kV on BPS reliability. | WECC RE, TOPs, TPs, PCs |
| *Finding 10 – Benchmarking WECC Dynamic Models*: The inquiry obtained a very good correlation between the simulations and the actual event until the SONGS separation scheme activated. After activation of the scheme, however, neither the tripping of the SONGS units nor the system collapse of SDG&E and CFE could be detected using WECC dynamic models because | *Recommendation 10*: WECC dynamic models should be benchmarked by TPs against actual data from the September 8th event to improve their conformity to actual system performance. In particular, improvements to model performance from validation would be helpful in analysis of under and/or over frequency events in the Western Interconnection and the stability of islanding scenarios in the SDG&E and CFE areas. | TPs |

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| some of the elements of the event are not explicitly included in those models. Sample simulations of the islanded region showed that by adding known details from the actual event, including UFLS programs and automatic capacitor switching, the simulation and event become more closely aligned following activation of the SONGS separation scheme. | | |
| **SITUATIONAL AWARENESS** | | |
| **FINDING** | **RECOMMENDATION** | **APPLICABLE ENTITIES** |
| *Finding 11 – Lack of Real-Time External Visibility*: Affected TOPs have limited real-time visibility outside their systems, typically monitoring only one external bus. As a result, they lack adequate situational awareness of external contingencies that could impact their systems. They also may not fully understand how internal contingencies could affect SOLs in their neighbors' systems. | *Recommendation 11*: TOPs should engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems. They should obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the SOLs of other TOPs. In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS. | TOPs |
| *Finding 12 – Inadequate Real-Time Tools*: Affected TOPs' real-time tools are not adequate or, in one case, operational to provide the situational awareness necessary to identify contingencies and reliably operate their systems. | *Recommendation 12*: TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems. | TOPs |
| *Finding 13 – Reliance on Post-Contingency Mitigation Plans*: One affected TOP operated in an unsecured N-1 state on September 8, 2011, when it relied on post-contingency mitigation plans for its internal contingencies and subsequent overload and tripping, while assuming there would be sufficient time to mitigate the contingencies. Post-contingency mitigation plans are not viable under all circumstances, such as when equipment trips on overload relay protection that prevents operators from taking timely control actions. If this TOP had used pre-contingency measures on | *Recommendation 13*: TOPs should review existing operating processes and procedures to ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions, including control actions, to return the system to a secure N-1 state as soon as possible but no longer than 30 minutes following a single contingency. As part of this review, TOPs should consider the effect of relays that automatically isolate facilities without providing operators sufficient time to take mitigating measures. | TOPs |

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| September 8th, such as dispatching additional generation, to mitigate first contingency emergency overloads for its internal contingencies, the cascading outages that were triggered by the loss of H-NG might have been avoided with the prevailing system conditions on September 8, 2011. | | |
| *Finding 14 – WECC RC Staffing Concerns*: WECC RC staffs a total of four operators at any one time to meet the functional requirements of an RC, including continuous monitoring, conducting studies, and giving directives. The September 8th event raises concerns that WECC RC's staffing is not adequate to respond to emergency conditions. | *Recommendation 14*: WECC RC should evaluate the effectiveness of its staffing level, training and tools. Based on the results of this evaluation, it should determine what actions are necessary to perform its functions appropriately as the RC and address any identified deficiencies. | WECC RC |
| *Finding 15 – Failure to Notify WECC RC and Neighboring TOPs Upon Losing RTCA*: On September 8, 2011, at least one affected TOP lost the ability to conduct RTCA more than 30 minutes prior to and throughout the course of the event due to the failure of its State Estimator to converge. The entity did not notify WECC RC or any of its neighboring TOPs, preventing this entity from regaining situational awareness. | *Recommendation 15*: TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities. | TOPs |
| *Finding 16 – Discrepancies Between RTCA and Planning Models*: WECC's model used by TOPs to conduct RTCA studies is not consistent with WECC's planning model and produces conflicting solutions. | *Recommendation 16*: WECC should ensure consistencies in model parameters between its planning model and its RTCA model and should review all model parameters on a consistent basis to make sure discrepancies do not occur. | WECC |
| **CONSIDERATION OF BES EQUIPMENT** | | |
| **FINDING** | **RECOMMENDATION** | **APPLICABLE ENTITIES** |
| *Finding 17 – Impact of Sub-100 kV Facilities on BPS Reliability*: WECC RC and affected TOPs and BAs do not consistently recognize the adverse impact sub-100 kV facilities can have on BPS reliability. As a result, sub-100 kV facilities might not be designated | *Recommendation 17*: WECC, as the RE should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and actively monitored and alarmed in RTCA systems. | WECC RE, TOPs, BAs |

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| as part of the BES, which can leave entities unable to address the reliability impact they can have in the planning and operations time horizons. If, prior to September 8, 2011, certain sub-100 kV facilities had been designated as part of the BES and, as a result, were incorporated into the TOPs' and RC's planning and operations studies, or otherwise had been incorporated into these studies, cascading outages may have been avoided on the day of the event. | | |
| **IROL DERIVATIONS** | | |
| **FINDING** | **RECOMMENDATION** | **APPLICABLE ENTITIES** |
| *Finding 18 – Failure to Establish Valid SOLs and Identify IROLs*: The cascading nature of the event that led to uncontrolled separation of San Diego, IID, Yuma, and CFE indicates that an IROL was violated on September 8, 2011, even though WECC RC did not recognize any IROLs in existence on that day. In addition, the established SOL of 2,200 MW on Path 44 and 1,800 MW on H-NG are invalid for the present infrastructure, as demonstrated by the event. | *Recommendation 18.1*: WECC RC should recognize that IROLs do exist on its system and, thus, should study IROLs in the day-ahead timeframe and monitor potential IROL exceedances in real-time.<br><br>*Recommendation 18.2*: WECC RC should work with TOPs to consider whether any SOLs in the Western Interconnection constitute IROLs. As part of this effort, WECC RC should: (1) work with affected TOPs to consider whether Path 44 and H-NG should be recognized as IROLs; and (2) validate existing SOLs, and ensure that they take into account all transmission and generation facilities and protection systems that impact BPS reliability. | WECC RC, TOPs |
| **PROTECTION SYSTEMS** | | |
| **FINDING** | **RECOMMENDATION** | **APPLICABLE ENTITIES** |
| *Finding 19 – Lack of Coordination of the S Line RAS*: Several TOs and TOPs did not properly coordinate a RAS by: (1) not performing coordination studies with the overload protection schemes on the facilities that the S Line RAS is designed to protect; and (2) not assessing the impact of setting relays to trip generation sources and a 230 kV transmission tie line prior to the operation of a single 161/92 kV transformer's overload protection. As a result, BES facilities were isolated in excess of those needed to maintain reliability, with adverse impact on | *Recommendation 19*: The TOs and TOPs responsible for design and coordination of the S Line RAS should revisit its design basis and protection settings to ensure coordination with other protection systems in order to prevent adverse impact to the BPS, premature operation, and excessive isolation of facilities. TOs and TOPs should share any changes to the S Line RAS with TPs and PCs so that they can accurately reflect the S Line RAS when planning. | TOs, TOPs |

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| BPS reliability. | | |
| *Finding 20 – Lack of Coordination of the SONGS Separation Scheme*: SCE did not coordinate the SONGS separation scheme with other protection systems, including protection and turbine control systems on the two SONGS generators. As a result, SCE did not realize that Units 2 and 3 at SONGS would trip after operation of the separation scheme. | *Recommendation 20*: SCE should ensure that the SONGS separation scheme is coordinated with other protection schemes, such as the generation protection and turbine control systems on the units at SONGS and UFLS schemes. | SCE |
| *Finding 21 – Effect of SONGS Separation Scheme on SONGS Units*: The SONGS units tripped due to their turbine control systems detecting unacceptable acceleration following operation of the SONGS separation scheme. | *Recommendation 21*: GOs and GOPs should evaluate the sensitivity of the acceleration control functions in turbine control systems to verify that transient perturbations or fault conditions in the transmission system resulting in unit acceleration will not result in unit trip without allowing time for protective devices to clear the fault on the transmission system. | GOs, GOPs |
| *Finding 22 – Lack of Review and Studying Impact of SPSs*: Although WECC equates SPSs with RASs, prior to October 1, 2011, WECC's definition of RAS excluded many protection systems that would be included within NERC's definition of SPS. As a result, WECC did not review and assess all NERC-defined SPSs in its region, and WECC's TOPs did not perform the required review and assessment of all NERC-defined SPSs in their areas. | *Recommendation 22*: WECC RE, along with TOs, GOs, and Distribution Providers (DPs), should periodically review the purpose and impact of RASs, including Safety Nets and Local Area Protection Schemes, to ensure they are properly classified, are still necessary, serve their intended purposes, are coordinated properly with other protection systems, and do not have unintended consequences on reliability. WECC RE and the appropriate TOPs should promptly conduct these reviews for the SONGS separation scheme and the S Line RAS. | WECC RE, TOs, GOs, DPs, TOPs |
| *Finding 23 – Effect of Inadvertent Operation of SONGS Separation Scheme on BPS Reliability*: The inquiry's simulation of the event shows that the inadvertent operation of the SONGS separation scheme under normal system operations could lead to a voltage collapse and blackout in the SDG&E areas under certain high load conditions. | *Recommendation 23*: CAISO and SCE should promptly verify that the inadvertent operation of the SONGS separation scheme does not pose an unacceptable risk to BPS reliability. Until this verification can be completed, they should consider all actions to minimize this risk, up to and including, temporarily removing the SONGS separation scheme from service. | CAISO, SCE |
| *Finding 24 – Not Recognizing Relay Settings When Establishing SOLs*: An affected TO did not properly establish the SOL for two transformers, as the SOL did not | *Recommendation 24*: TOs should reevaluate their facility ratings methodologies and implementation of the methodologies to ensure that their ratings are equal to the most limiting piece of equipment, including relay | TOs |

| | | |
|---|---|---|
| recognize that the most limiting elements (protective relays) were set to trip below the established emergency rating. As a result, the transformers tripped prior to the facilities being loaded to their emergency ratings during the restoration process, which delayed the restoration of power to the Yuma load pocket. | settings. No relay settings should be set below a facility's emergency rating. When the relay setting is determined to be the most limiting piece of equipment, consideration should be given to reviewing the setting to ensure that it does not unnecessarily restrict the transmission loadability. | |
| *Finding 25 – Margin Between Overload Relay Protection Settings and Emergency Rating*: Some affected TOs set overload relay protection settings on transformers just above the transformers' emergency rating, resulting in facilities being automatically removed from service before TOPs have sufficient time to take control actions to mitigate the resulting overloads. One TO in particular set its transformers' overload protection schemes with such narrow margins between the emergency ratings and the relay trip settings that the protective relays tripped the transformers following an N-1 contingency. | *Recommendation 25*: TOs should review their transformers' overload protection relay settings with their TOPs to ensure appropriate margins between relay settings and emergency ratings developed by TOPs. For example, TOs could consider using the settings of Reliability Standard PRC-023-1 R.1.11 even for those transformers not classified as BES. PRC-023-1 R.1.11 requires relays to be set to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. | TOs, TOPs |
| *Finding 26 –Relay Settings and Proximity to Emergency Ratings*: Some TOs set relays to isolate facilities for loading conditions slightly above their thirty minute emergency ratings. As a result, several transmission lines and transformers tripped within seconds of exceeding their emergency ratings, leaving TOPs insufficient time to mitigate overloads. | *Recommendation 26*: TOs should evaluate load responsive relays on transmission lines and transformers to determine if the settings can be raised to provide more time for TOPs to take manual action to mitigate overloads that are within the short-time thermal capability of the equipment instead of allowing relays to prematurely isolate the transmission lines. If the settings cannot be raised to allow more time for TOPs to take manual action, TOPs must ensure that the settings are taken into account in developing facility ratings and that automatic isolation does not result in cascading outages. | TOs, TOPs |
| **ANGULAR SEPARATION** | | |
| **FINDING** | **RECOMMENDATION** | **APPLICABLE ENTITIES** |
| *Finding 27 – Phase Angle Difference Following Loss of Transmission Line*: A TOP did not have tools in place to determine the phase angle difference between the two terminals of its 500 kV line after the line tripped. Yet, it informed the RC and another TOP that the line would be restored | *Recommendation 27*: TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operating plans for reclosing lines with large phase angle differences. TOPs should also train operators to effectively respond to phase angle differences. These plans should be developed based on the seasonal and next-day contingency analyses | TOPs |

| | | |
|---|---|---|
| quickly, when, in fact, this could not have been accomplished. | that address the angular differences across opened system elements. | |

# Appendix C: Comparison of August 2003 and September 2011 Blackouts

On August 14, 2003, an estimated 50 million people throughout the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. A day later, the joint U.S.-Canada Power System Outage Task Force began investigating the causes of the blackout and considering ways to prevent such outages in the future. The task force detailed its findings and recommendations in an April 2004 report.[105] A comparison of the findings and recommendations in this April 2004 report and the instant report on the September 8, 2011, blackout reveals commonalities between the two events.

Although the August 2003 and September 2011 blackouts were triggered by different initiating events—tree touches in 2003 compared to a switching error in 2011—both blackouts had common underlying causes. First, affected entities in both events did not conduct adequate long-term and operations planning studies necessary to understand vulnerabilities on their systems. Second, affected entities in both events had inadequate situational awareness leading up to and during the disturbances. In addition to these two underlying causes, both events were exacerbated by protection system relays that tripped facilities without allowing operators sufficient time to take mitigating measures. These similarities are highlighted below, with excerpts from both reports to illustrate specific comparisons.

### Inadequate Long-Term and Operations Planning

The 2003 Blackout Report states that "FirstEnergy was not [operating its system securely] because the company had not conducted the long-term and operational planning studies needed to understand [certain] vulnerabilities and their operational implications."[106] Similarly, this inquiry's report found that several entities' operational and long-term studies did not adequately ensure the reliable operation of their systems. Specifically, both reports described relevant planning studies that: (1) did not adequately identify and study critical external facilities; (2) did not adequately analyze potential contingency scenarios; and (3) were based on inaccurate models and invalid system operating limits (SOLs).

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

[106] 2003 Blackout Report at 23.

## Inadequate Long Term and Operations Planning

| Issue | 2003 Blackout | 2011 Blackout |
|---|---|---|
| Insufficient Analysis in Seasonal Studies | "[T]he studies FirstEnergy relied on . . . were not robust, thorough, or up-to-date. This left FE's planners and operators with a deficient understanding of their system's capabilities and risks under a range of system conditions." (P. 39).<br><br>"FE's 2003 Summer Study focused primarily on single-contingency (N-1) events, and did not consider significant multiple contingency losses and security. . . . Overall, the summer study posited less stressful system conditions than actually occurred August 14, 2003 (when load was well below historic peak demand)." (P 39). | "TOPs do not always run their individual seasonal planning studies based on the multiple WECC base cases (heavy and light load summer, heavy and light load winter, and heavy spring), but, instead, may focus on only one load level." (Finding 7)<br><br>"Seasonal planning studies do not adequately consider all facilities that may affect BPS reliability, including external facilities and lower-voltage facilities."(Finding 6)<br><br>"In the seasonal planning process, at least one TOP did not share with neighboring TOPs overload relay trip settings on transformers and transmission lines that impacted external BPS systems." (Finding 8) |
| Inadequate Identification and Study of Critical External Facilities | "On August 14 four or five capacitor banks within the Cleveland-Akron area had been removed from service for routine inspection. . . . These static reactive power sources are important for voltage support. . . . The unavailability of the critical reactive resources was not known to those outside of FirstEnergy." (PP. 26-27).<br><br>"NERC policy requires that critical facilities be identified and that neighboring control areas and reliability coordinators be made aware of the status of those facilities to identify the impact of those conditions on their own facilities. However, FE never identified these capacitor banks as critical and so did not pass on status information to others." (P. 27). | "Not all of the affected TOPs conduct next-day studies or share them with their neighbors and WECC RC. . . .TOPs were not alerted to contingencies on neighboring systems that could impact their internal system and the need to plan for such contingencies." (Finding 1)<br><br>"In conducting next-day studies, some affected TOPs focus primarily on the TOPs' internal SOLs and the need to stay within established Rated Path limits, without adequate consideration of some lower voltage facilities." (Finding 3)<br><br>"[In conducting next-day studies,] . . . the RC does not study sub-100 kV facilities that impact BPS reliability unless it has specifically been alerted to issues with such facilities by individual TOPs..." (Finding 3) |

| | | |
|---|---|---|
| Inaccurate Dynamic Models | "The after-the-fact models developed to simulate August 14 conditions and events found that the dynamic modeling assumptions for generator and load power factors in regional planning and operating models were frequently inaccurate." (P. 160). | ". . . neither the tripping of the SONGS units nor the system collapse of SDG&E and CFE could be detected using WECC dynamic models because some of the elements of the event are not explicitly included in those models." (Finding 10) |

To mitigate these concerns, the 2003 Blackout Report recommended that "NERC should work with the regional reliability councils to establish regional power system models that enable the sharing of consistent and validated data among entities in the region,"[107] and "[c]larify criteria for identification of operationally critical facilities, and improve dissemination of updated information on unplanned outages."[108] This inquiry's report likewise recommends that entities cooperate and coordinate more effectively across all planning horizons, especially by increasing visibility in both external systems and lower voltage facilities that could impact BPS reliability.

**Inadequate Situational Awareness**

The 2003 Blackout Report stated, "A principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools and backup capabilities."[109] Similarly, the instant inquiry determined that inadequate real-time situational awareness contributed to the cascading outages. In both events, for example, the affected entities' real-time monitoring tools were not adequate to alert operators to system conditions and contingencies. Also, some of the affected entities in both events did not use their real-time tools to monitor system conditions. As a result of these situational awareness issues, affected entities in both events were not aware that they were no longer operating in a secure N-1 state and were not alerted to the need to take corrective actions.

| Inadequate Situational Awareness | | |
|---|---|---|
| Issue | 2003 Blackout | 2011 Blackout |
| System Visibility | "MISO [the Reliability Coordinator] had interpretive and operational tools and a large amount of system data, but had a limited view of FE's system." (P. 67). | "Affected TOPs have limited real-time visibility outside their systems, typically monitoring only one external bus. As a result, they lack adequate situational awareness of external contingencies that could impact |

[107] 2003 Blackout Report at 160.

[108] 2003 Blackout Report at 3.

[109] 2003 Blackout Report at 159.

| Inadequate Situational Awareness | | |
|---|---|---|
| Issue | 2003 Blackout | 2011 Blackout |
| | | their systems. They also may not fully understand how internal contingencies could affect SOLs in their neighbors' systems." (Finding 11) |
| Inadequate Real-Time Monitoring Tools | "FE's operational monitoring equipment was not adequate to alert FE's operators regarding important deviations in operating conditions and the need for corrective action." (P. 19).<br><br>"FE's control room operators lost the alarm function that provided audible and visual indications when a significant piece of equipment changed from an acceptable to a problematic condition." (P. 51).<br><br>MISO's incomplete tool set and the failure to supply its state estimator with correct system data on August 14 contributed to the lack of situational awareness." (P. 159). | "Affected TOPs' real-time tools are not adequate or, in one case, operational to provide the situational awareness necessary to identify contingencies and reliably operate their systems." (Finding 12)<br>". . . a TOP lost the ability to conduct [Real Time Contingency Analysis] RTCA more than 30 minutes prior to and throughout the course of the event ...[and] did not notify WECC RC or any of its neighboring TOPs..."(Finding 15) |
| Operating in an Unsecure State | "FE's operators were not aware that the system was operating outside first contingency limits . . . because they did not conduct a contingency analysis." (P. 64).<br><br>"MISO's reliability coordinators were using non-real-time data to support real-time "flowgate" monitoring. This prevented MISO from detecting an N-1 security violation in FE's system and from assisting FE in necessary relief actions." (P. 19).<br><br>"Since FE's operators were not aware and did not recognize events as they were occurring, they took no actions to return the system to a reliable state." (P. 65). | "The cascading nature of the event that led to uncontrolled separation of San Diego, IID, Yuma, and CFE indicates that an [interconnection reliability operating limit] IROL was violated . . . In addition, the established SOLs of 2,200 MW on Path 44 and 1,800 MW on H-NG are invalid..."(Finding 18)<br><br>"One affected TOP operated in an unsecured N-1 state. . . . when it relied on post-contingency mitigation plans for its internal contingencies and subsequent overloads and trips, while assuming there would be sufficient time to mitigate the contingencies." (Finding 13) |

To remedy these weaknesses in situational awareness, the 2003 Blackout Report recommended that entities [e]valuate and adopt better real-time tools for operators and reliability coordinators."110 Similarly, this inquiry's report recommends that operators

**110** 2003 Blackout Report at 159.

develop and effectively utilize the real-time tools at their disposal and include all facilities that can impact BPS reliability.

**Protection Systems**

During both events, protection system settings exacerbated and accelerated the cascading nature of the outages. As stated in the 2003 Blackout Report, zone 3 relay settings "did not cause the blackout, [but] it is certain that they greatly expanded and accelerated the spread of the cascade."[111] Similarly, load responsive relay settings accelerated the September 8th cascade and effectively eliminated the window in which operators could have taken mitigating actions.

| Protection Systems | | |
|---|---|---|
| **Issue** | **2003 Blackout** | **2011 Blackout** |
| Overly Conservative Relay Protection Settings | "A few lines have zone 3 settings designed with overload margins close to the long-term emergency limit of the line. . . .Thus, it is possible for a zone 3 relay to operate on line load or overload in extreme contingency conditions even in the absence of a fault." (P. 80) | "Some affected TOs set overload relay protection settings on transformers just above the transformers' emergency rating, resulting in facilities being automatically removed from service before TOPs have sufficient time to take control actions . . . following an N-1 contingency." (Finding 25) |
| Cascading Relay Overload Trips | "[B]ecause these zone 2 and 3 relays tripped after each line overloaded, these relays were the common mode of failure that accelerated the geographic spread of the cascade." (P. 80) | "Some TOs set relays to isolate facilities for loading conditions slightly above their thirty minute emergency ratings. As a result, several transmission lines and transformers tripped within seconds of exceeding their emergency ratings, leaving TOPs insufficient time to mitigate overloads." (Finding 26) |
| Relay Protection Acting Too Quickly to Allow System Operators to Take Action | "[T]he speed of the zone 2 and 3 operations across Ohio and Michigan eliminated any possibility . . . that either operator action or automatic intervention could have limited or mitigated the growing cascade." (P. 80). | "Some affected TOs set overload relay protection settings on transformers just above the transformers' emergency rating, resulting in facilities being automatically removed from service before TOPs have sufficient time to take control actions..." (Finding 25)<br><br>". . . several transmission lines |

[111] 2003 Blackout Report at 82. Zone 3 relays "provide breaker failure and relay backup for remote distance faults on a transmission line." *Id.* at 80.

| Protection Systems | | |
|---|---|---|
| **Issue** | **2003 Blackout** | **2011 Blackout** |
| | | and transformers tripped within seconds of exceeding their emergency ratings, leaving TOPs insufficient time to mitigate overloads. (Finding 26) |

After seeing the consequences of conservative zone 3 settings, the 2003 Blackout Report recommended that "[i]ndustry is to review zone 3 relays on lines of 230 kV and higher."[112] This inquiry's report similarly recommends that Transmission Owners review their facilities' overload relay protection settings to ensure the appropriate margin between relay settings and emergency ratings.

[112] 2003 Blackout Report at 158.

# Appendix D: Benchmarking the Model

## I. Introduction and Background

The inquiry's Modeling and Simulation Team replicated system conditions on September 8, 2011, and the events leading up to the blackout. The model reflects the state of the electric system before and during the event, with the real power output of generators dispatched to the values recorded in SCADA data. With any major event on the BPS, it is important to accurately model the system before and during the event in order to: (1) verify the Sequence of Events; (2) support reconciliation of disparate measurement data; and (3) simulate and evaluate hypothetical scenarios, or "what-if" scenarios.

In order to ensure the accuracy of these tasks, the Modeling and Simulation Team benchmarked the model to recorded SCADA and PMU measurements using the following guidelines. Key facilities and interfaces in the affected area were generally benchmarked to within 5% or 10 MVA accuracy to the measured data. Generator reactive outputs were also checked against recorded values to ensure that the representation of reactive power margin was reasonably accurate. The team also monitored most other facilities in the affected area to ensure that the flows and voltage were reasonably close to measured data. Many of these other facilities also met the same guidelines used to benchmark the key facilities and interfaces.

The iterative process between benchmarking and case alteration has traditionally been time-consuming. The team pursued methods that would ultimately decrease the amount of time spent benchmarking so that results could quickly be used to identify problem areas in the case and make appropriate adjustments. Because the team received SCADA and PMU measurement data from many sources and entities, the data was: (1) organized into a consistent format, useful for automated benchmarking; and (2) cross-checked and verified for accuracy. In organizing the data, the team also considered how each data point would map back to both power flow and dynamics results. The team ultimately achieved a single process to: (1) import power flow results; (2) import dynamics results; (3) compare the results to measured data from many sources at various quasi-steady state times during the event; (4) export tables showing the percentage accuracy; and (5) export graphs showing the accuracy of the results relative to measured data throughout the event.

## II. Discussion

The locations and measurements that the team selected for benchmarking were naturally predicated on the available measurements. While the team compared each available data point to the model results, it did not benchmark the model to all available data points. Instead the team focused its benchmarking effort on a "study area" that included SDG&E, IID, the APS Yuma load pocket, and portions of CFE and SCE. The team gave preference to measurements that were available in multiple data sources with some reasonable agreement between the different sources, and particular preference to those locations where PMU measurements were available, because these measurements could also be benchmarked against a full dynamics simulation.

Following each set of simulations, the team reviewed the benchmarking data both graphically and tabularly, and tuned the modeling case and simulation parameters in an attempt to bring the case closer to measured reality. The team would then re-run the simulation, and repeat this process.

### Custom Interfaces

Even though the team selected the best possible set of benchmarking data, and a substantial amount of work went into calibrating the study area of the modeling case to those measurements, inconsistencies between some data points persisted. These inconsistencies arose due to the multitude of subtle settings and parameters for equipment, such as a changed tap on a single transformer affecting reactive power flow. For this reason, the team developed "custom interfaces" to benchmark an aggregation of points. If an aggregated, modeled sub-system was very close to the actual measurements for that system, then the simulation could be trusted to accurately reflect the system. For example, if reactive power flow was misallocated to a pair of adjacent transformers sourcing a sub-system, the specific reactive flow on each transformer may not be of particular importance to the model. However, the reactive flow to the aggregate load being served by those transformers may have a significant impact on a neighboring sub-system, and be crucial to effective benchmarking.

The custom interfaces were also defined so as to indicate the amount of flow into or across a particular sub-system. For example, the calculated flows at the "IID North 92 kV System" interface give an idea of the amount and nature of the load in the northern IID 92 kV system. The custom interfaces selected include:

- **IID North 92 kV System:** All transmission sources for the northern IID 92 kV system, including the 230/92 kV transformers at Coachella Valley and Ramon, the 161/92 kV transformers at Coachella Valley and Avenue 58, and the 92 kV lines between the northern and southern IID systems.

- **IID South 92 kV System:** All transmission sources for the southern IID 92 kV system, including the 230 kV transformer at El Centro, the 161/92 kV transformers at El Centro and Niland, and the 92 kV lines between the southern and northern IID systems.
- **Yuma Pocket:** Interfaces between the Yuma area 69 kV system (including portions of both APS and WALC service territories) and higher-voltage systems, including the 500/69 kV transformers at N. Gila, the 161/69 kV transformers at Gila, and the 161 kV line from Pilot Knob to Yucca.
- **Southwest California Desert Imports:** All transmission sources into the IID/SDG&E/CFE/Yuma area other than Path 44.

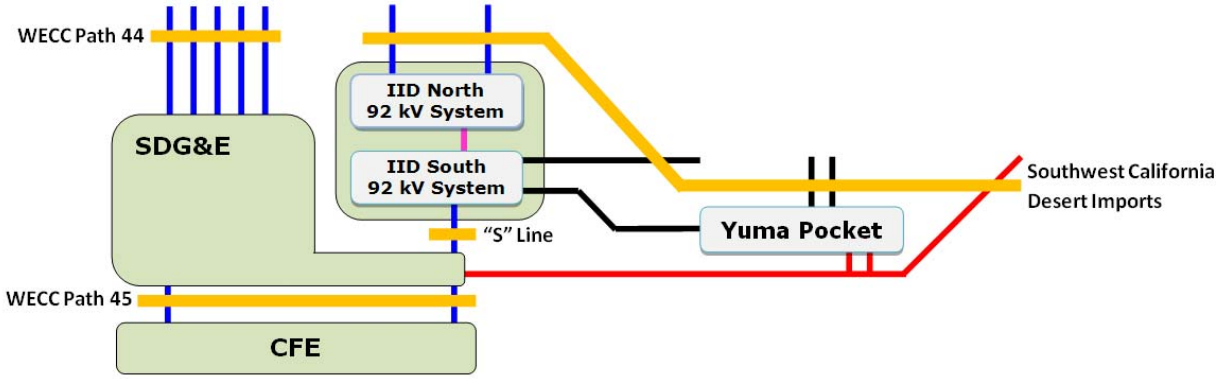



**Figure 1: Key Facilities and Interfaces**

## Key Facilities and Interfaces

The team chose key facilities and interfaces in the affected area as a way to quickly evaluate the model before fine-tuning it on a more granular level. These key facilities and interfaces were benchmarked to within 5% or 10 MVA accuracy to the measured data throughout the entire event. The key facilities and interfaces are listed below.

- WECC Path 44
- Southwest California Desert Imports
- IID Northern 92 kV System
- Niland-Blythe 161 kV Transmission Line
- IID Southern 92 kV System
- Imperial Valley-El Centro 230 kV Transmission Line ("S" Line)
- Miguel-Imperial Valley 500 kV Transmission Line
- Yuma Pocket
- El Centro-Pilot Knob 161 kV Transmission Line
- Pilot Knob-Knob 161 kV Transmission Line
- Pilot Knob-Yucca 161 kV Transmission Line
- Julian Hinds-Mirage 230 kV Transmission Line
- Julian Hinds-Eagle Mountain 230 kV Transmission Line

## III. Results

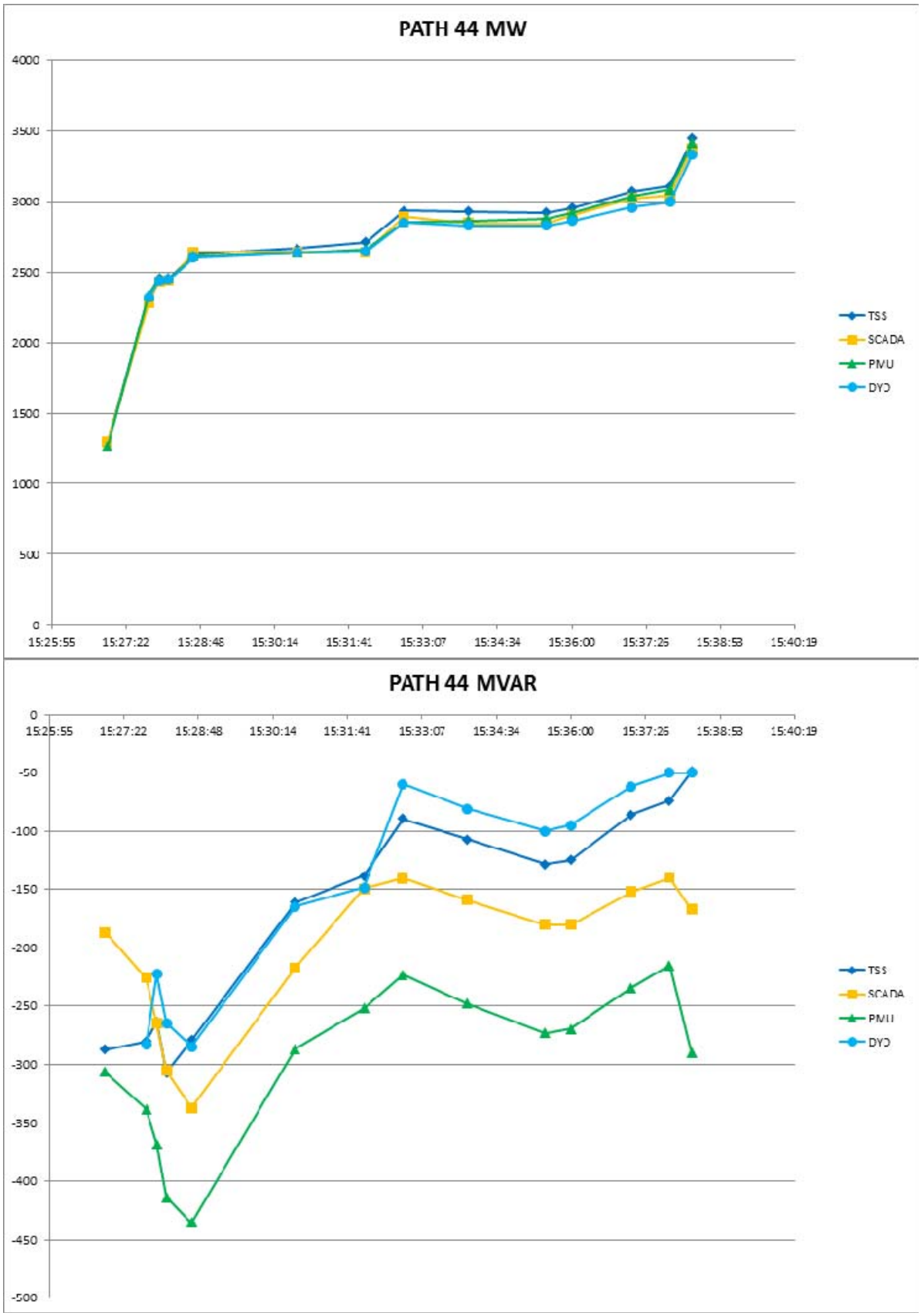
The following graphs demonstrate the benchmarking results. Each plot gives both power flow (see "TSS" in graph legend)[113] and dynamic simulation (see "DYD" in graph legend)[114] results at each selected time step, with the corresponding SCADA and/or PMU measurement, as available. In some instances, known issues with measured data are annotated on the charts, such as SCADA measurement errors for Coachella Valley during the interval following the initiating event.

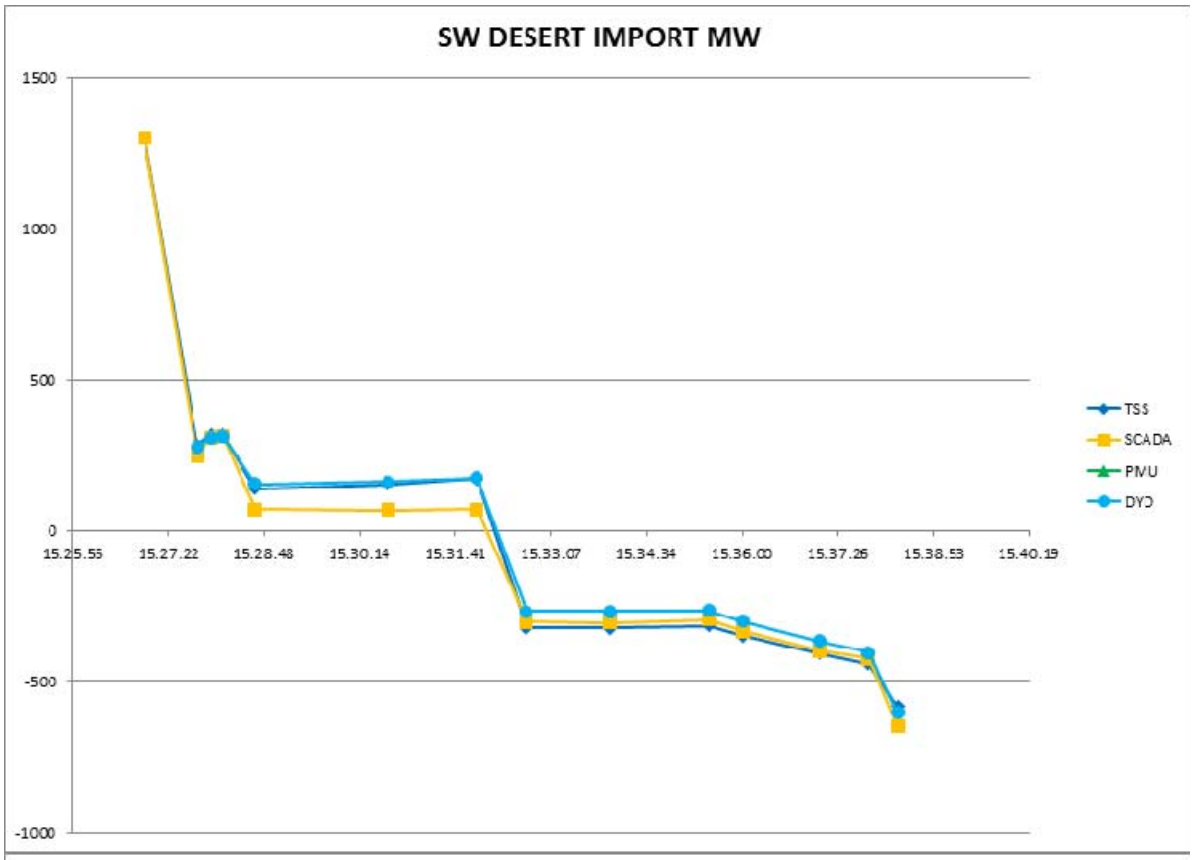
The simulated MW values follow the measurements more closely than the simulated MVAR values. This is due to complexity involved in tuning voltage at each bus due to incomplete data, such as unknown tap values on large transformers. Overall, the MVA values are within our benchmarking guidelines.

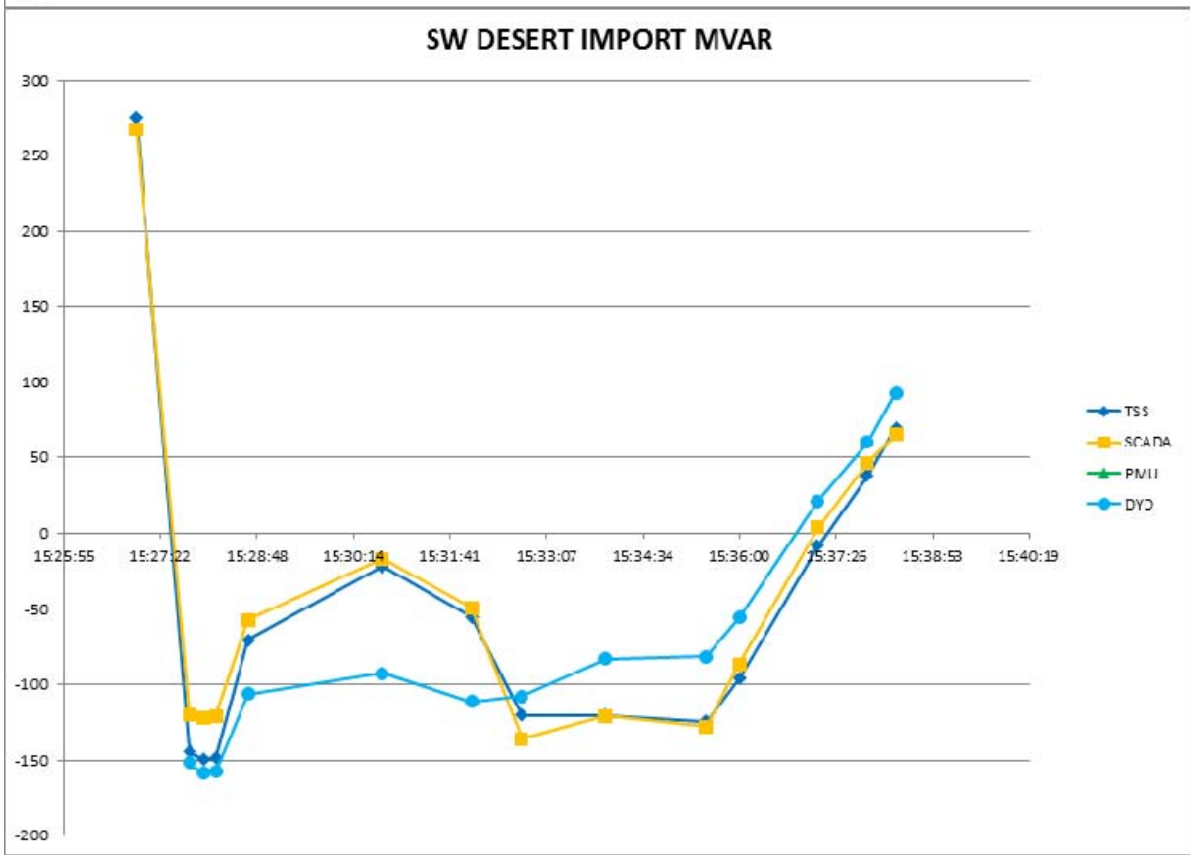
The team also provided a table that compares: (1) the base case at 15:27:00 to the measured data; and (2) the case just prior to the loss of the Coachella Valley transformers at 15:28:11 to the measured data. This table does not compare the dynamics values to the base case at 15:27:00 because the power flow base case was the foundation for the dynamics simulation, meaning the values would be equal.

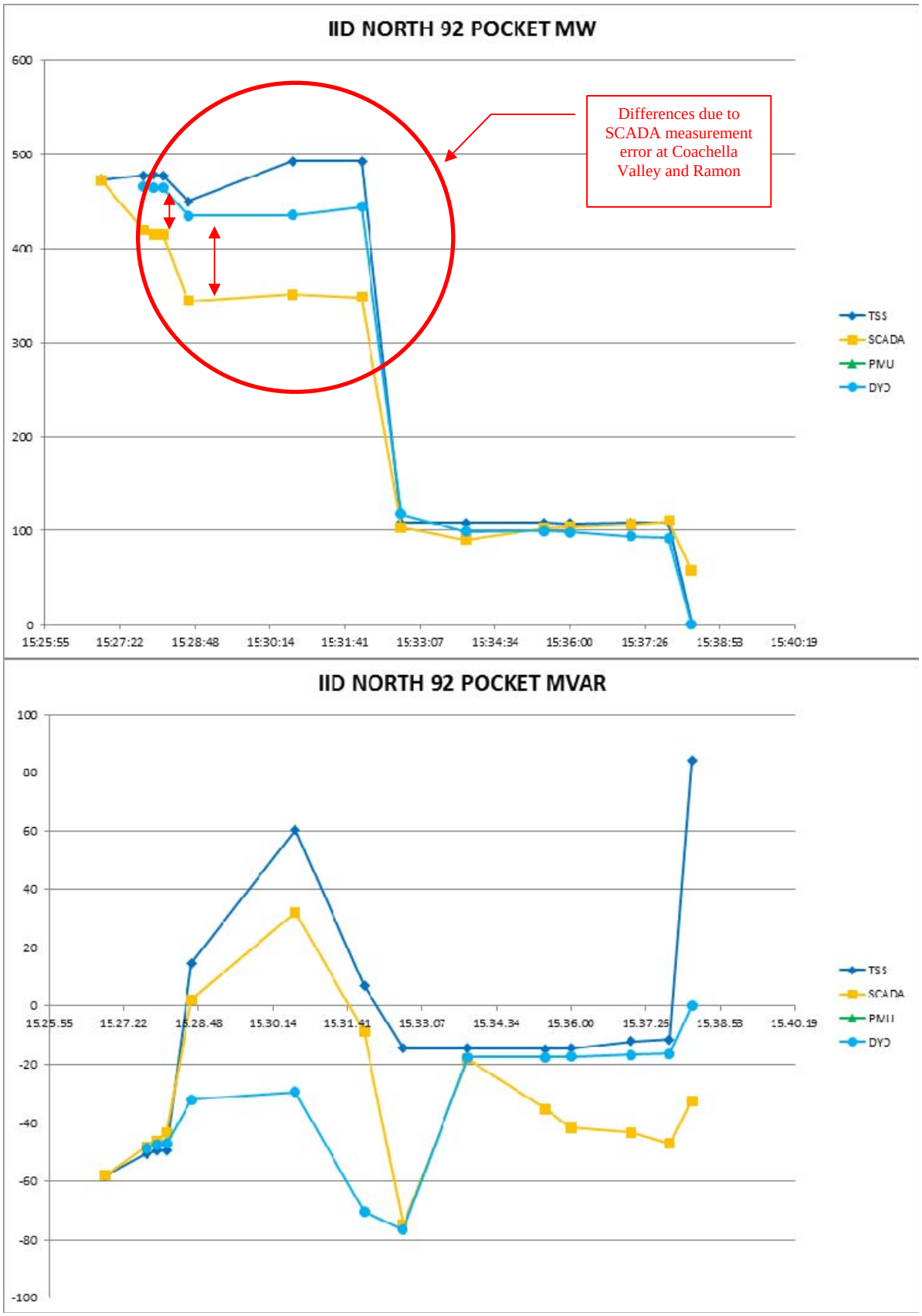
[113] Time Sequence Simulation.

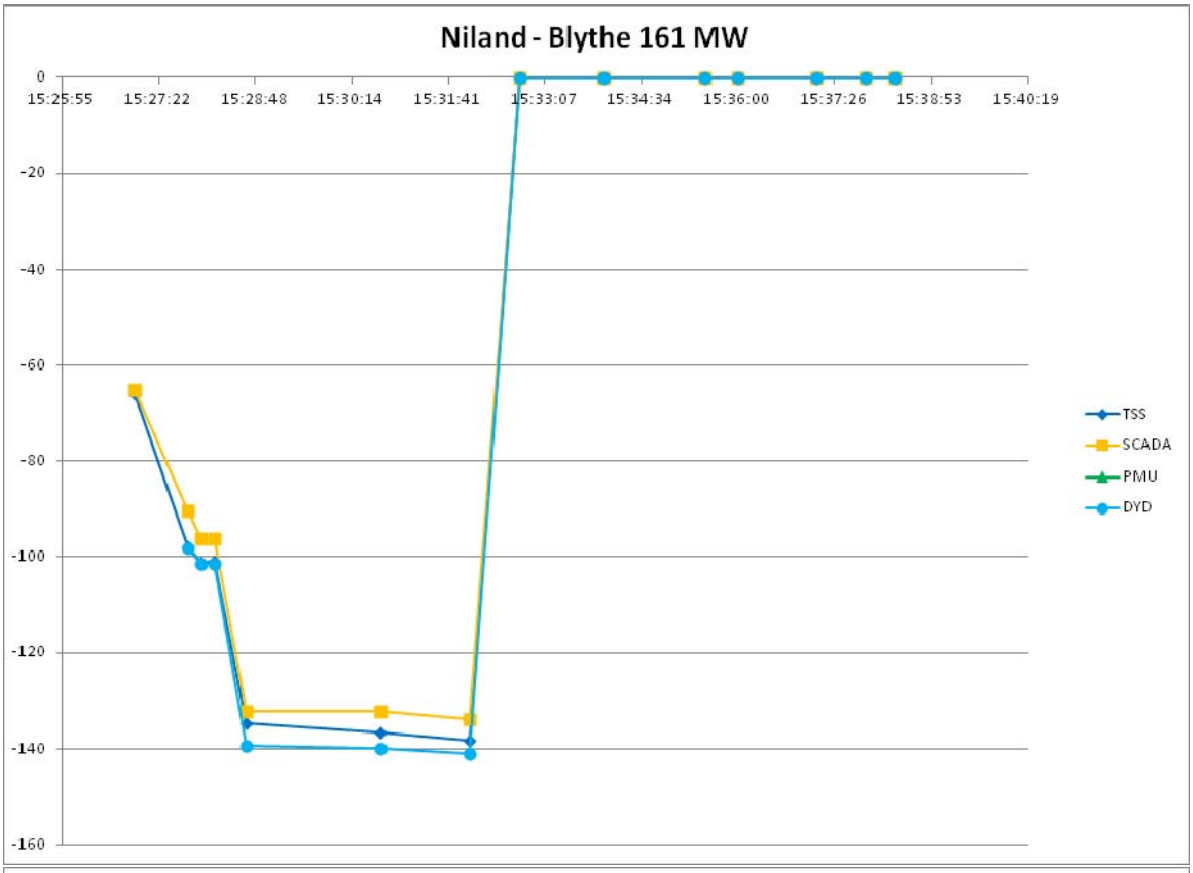
[114] Dynamics Data.

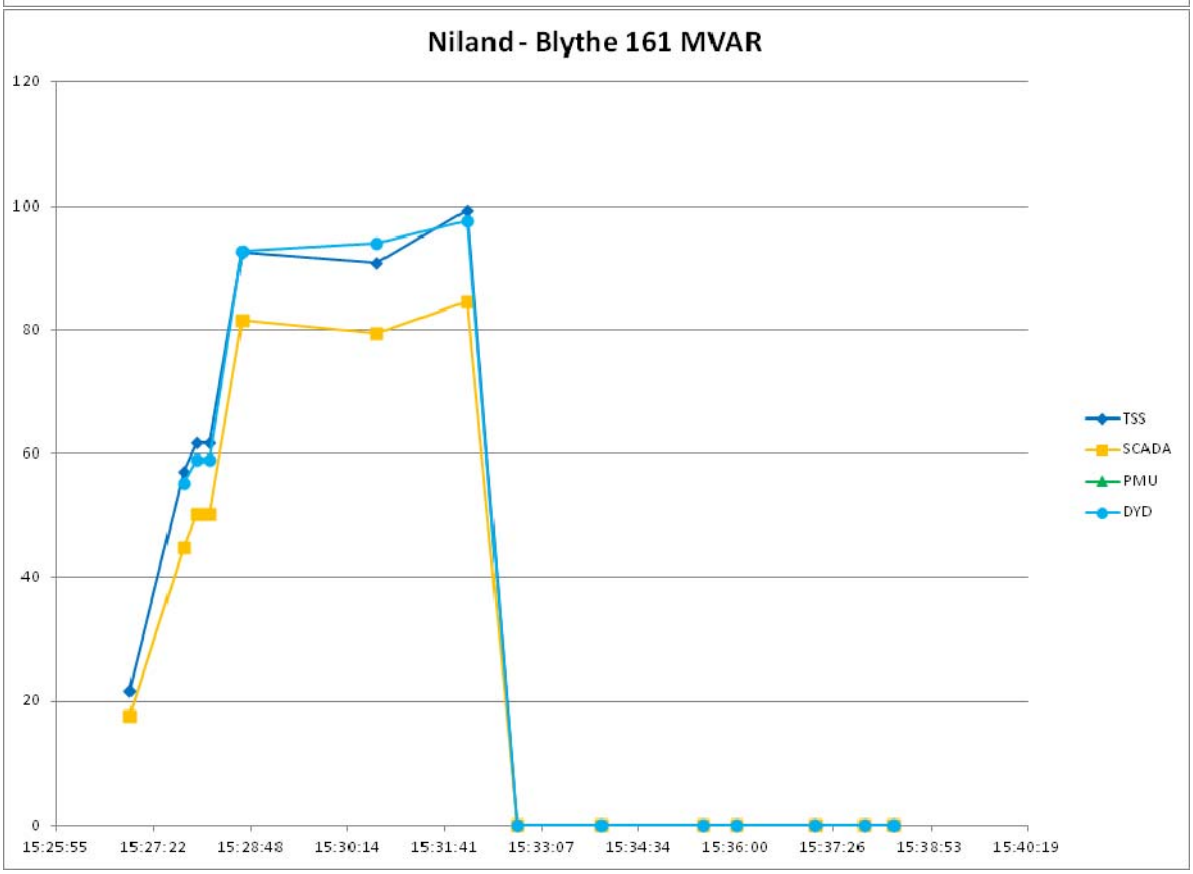

PATH 44 MW
4000
3500
3000
2500
2000
1500
1000
500
0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:25
15:38:53
15:40:19
TSS
SCADA
PMU
DYD
PATH 44 MVAR
0
-50
-100
-150
-200
-250
-300
-350
-400
-450
-500
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
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TSS
SCADA
PMU
DYD

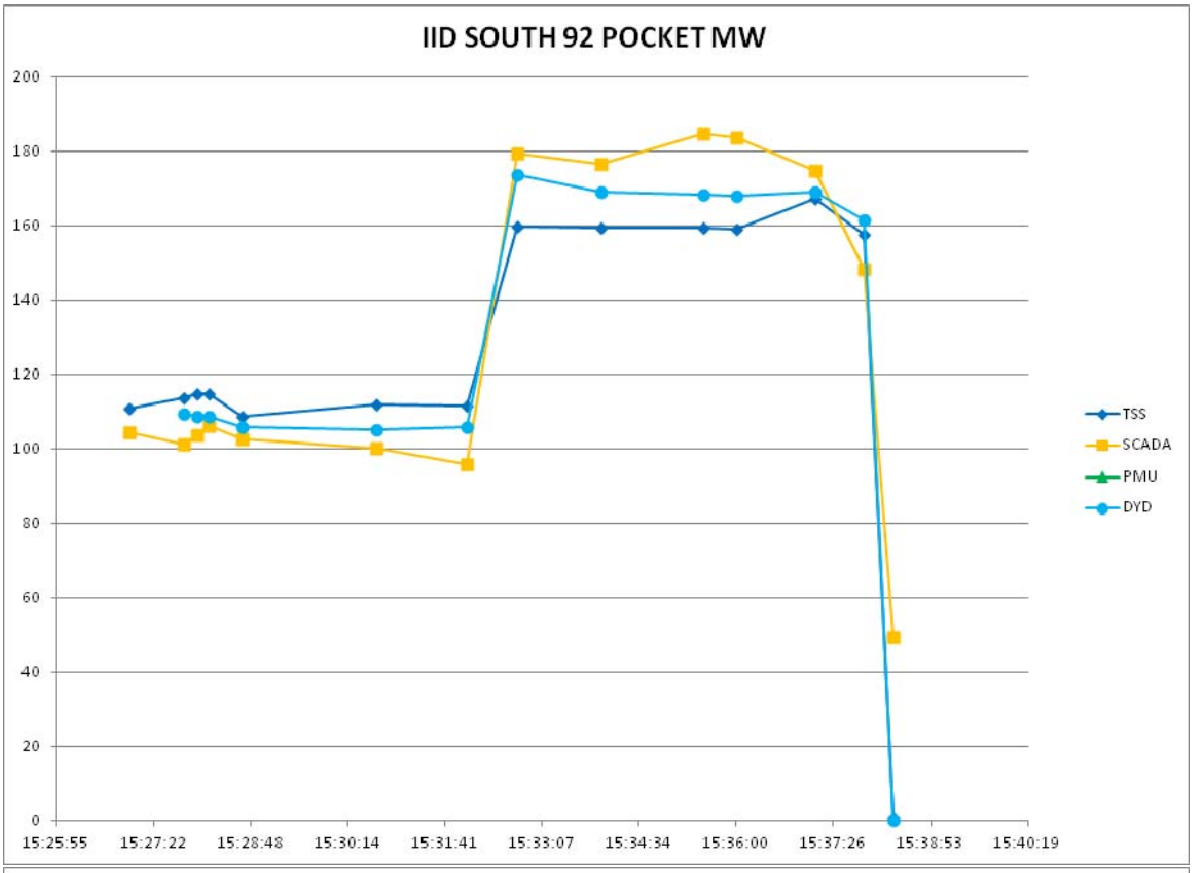

SW DESERT IMPORT MW
1500
1000
500
0
-500
-1000
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
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15:40:19
TSS
SCADA
PMU
DYD

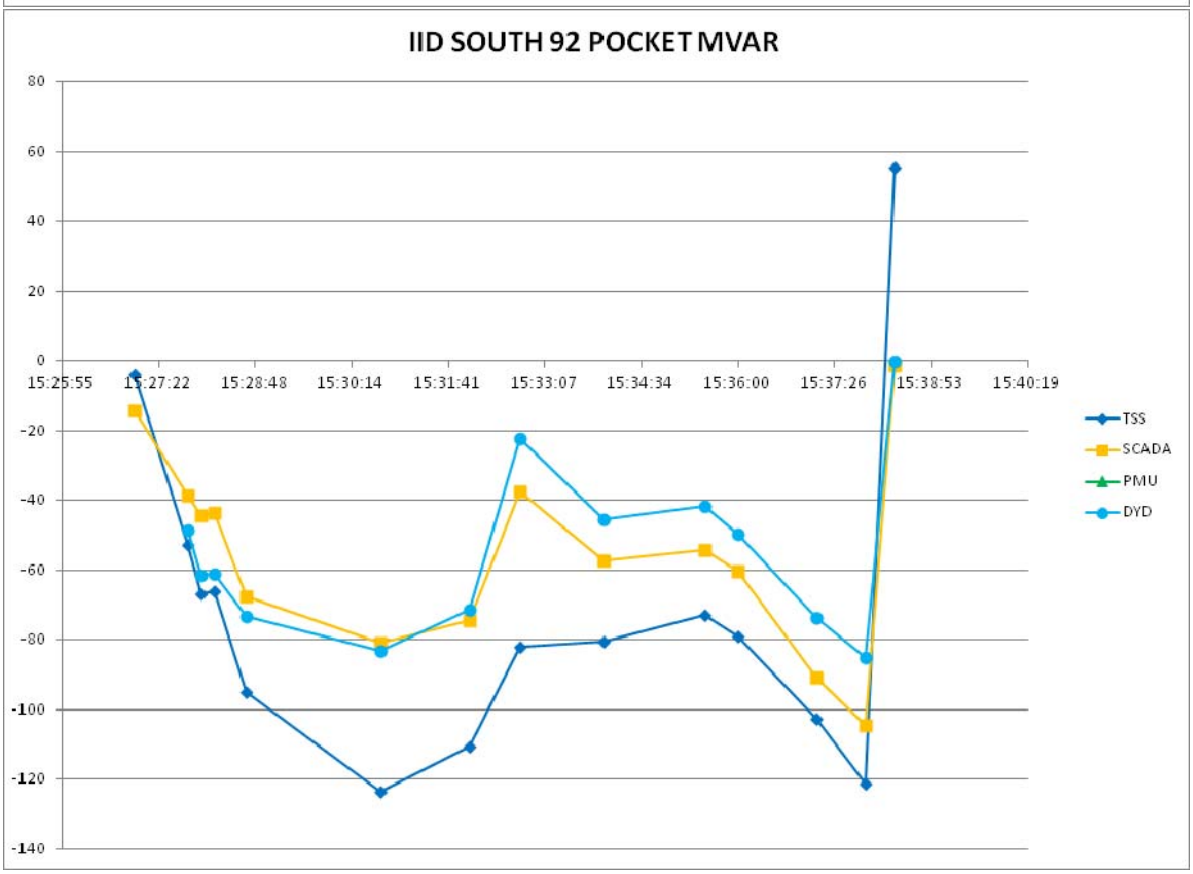

SW DESERT IMPORT MVAR
300
250
200
150
100
50
0
-50
-100
-150
-200
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
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TSS
SCADA
PMU
DYD

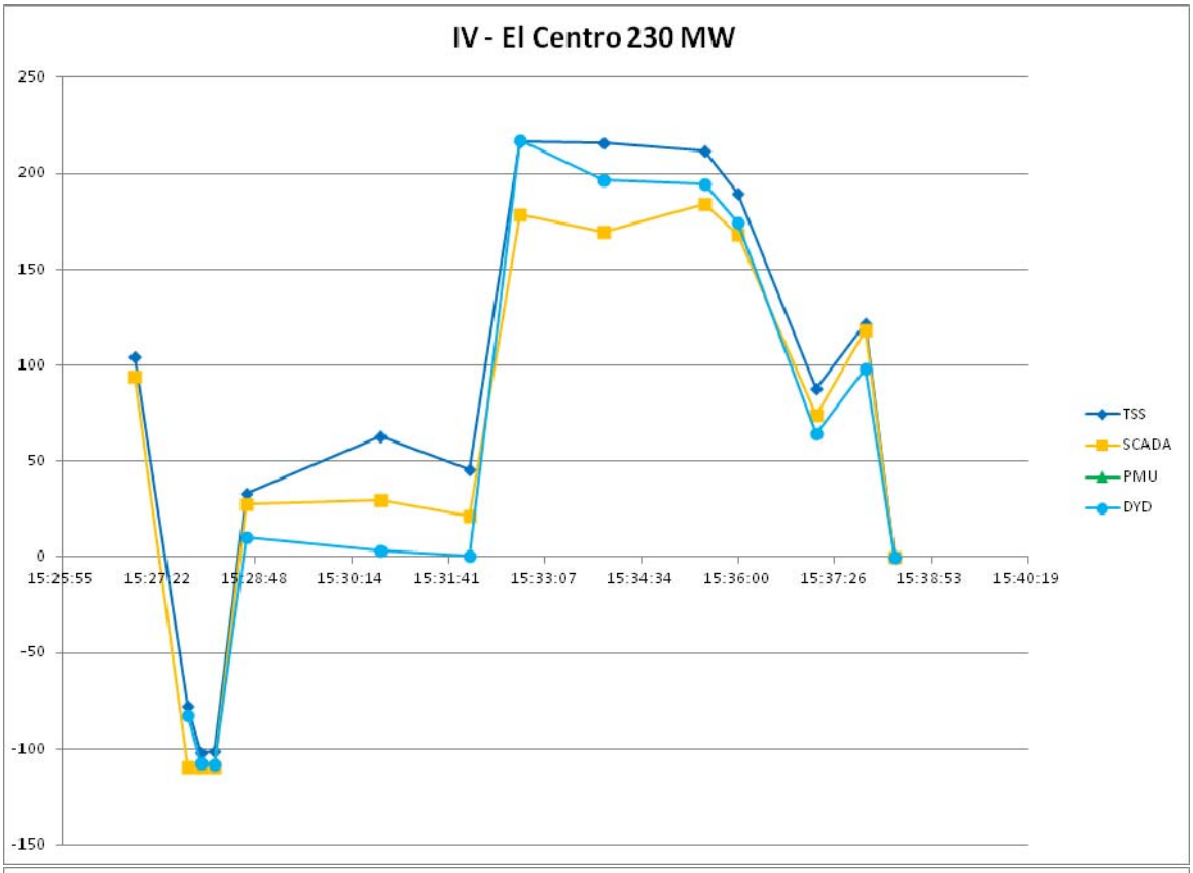

IID NORTH 92 POCKET MW
600
500
400
300
200
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0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
Differences due to SCADA measurement error at Coachella Valley and Ramon
TSS
SCADA
PMU
DYD
IID NORTH 92 POCKET MVAR
100
60
40
20
0
-20
-40
-60
-80
-100
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

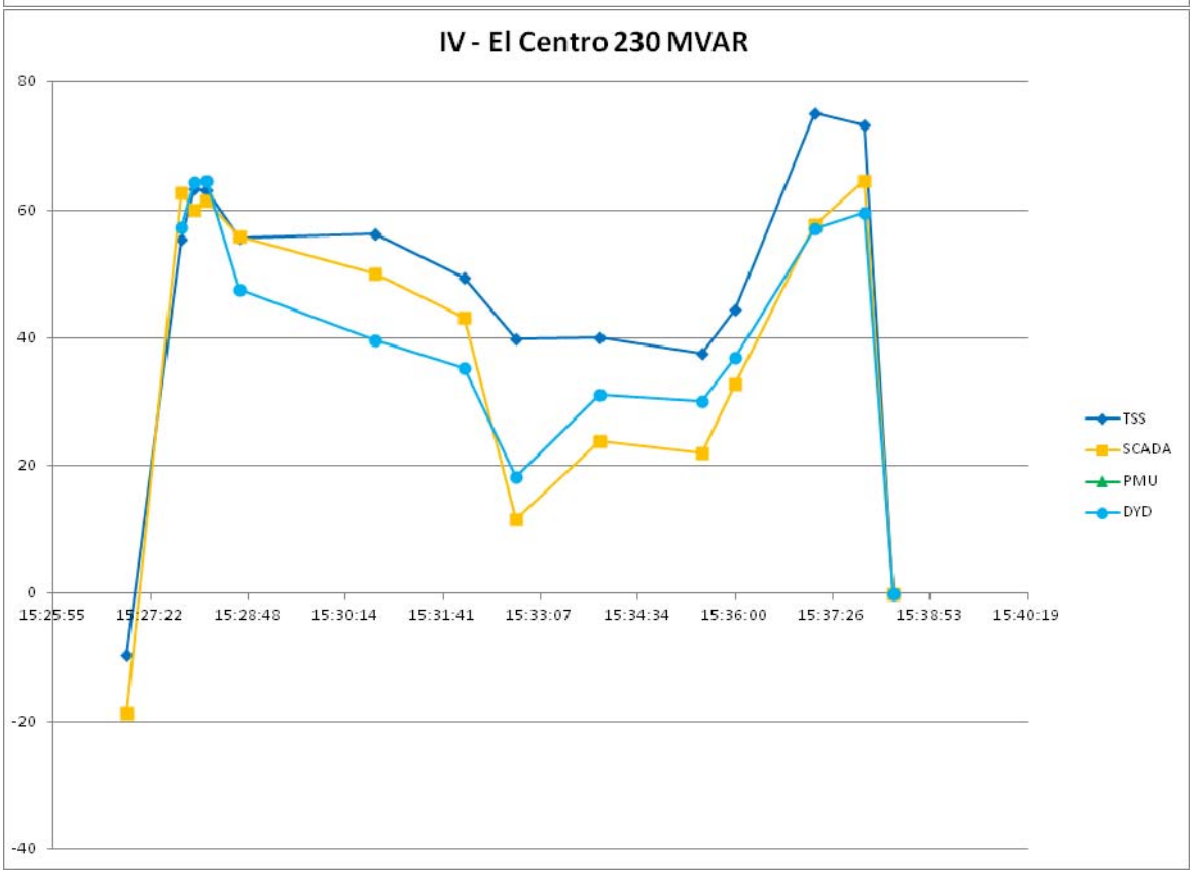

Niland - Blythe 161 MW
0
-20
-40
-60
-80
-100
-120
-140
-160
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

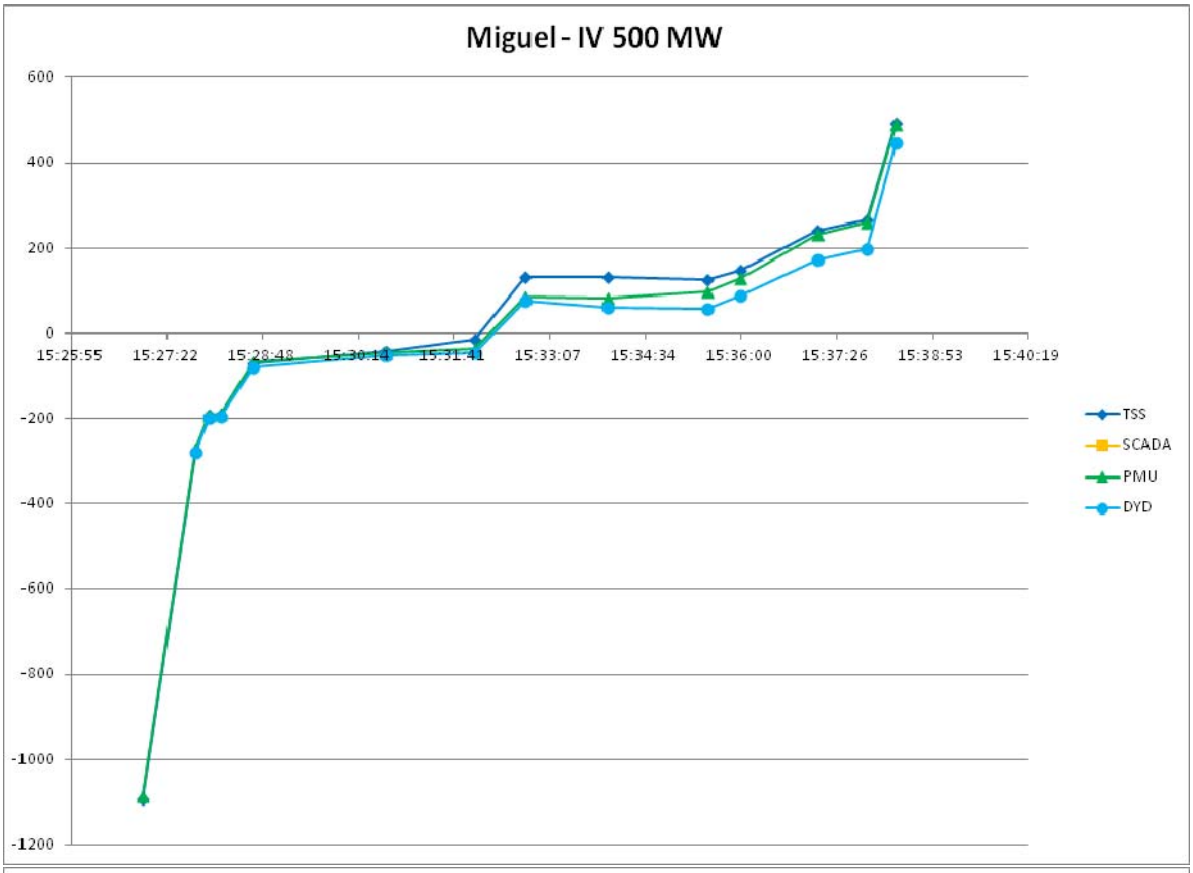

Niland - Blythe 161 MVAR
120
100
80
60
40
20
0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

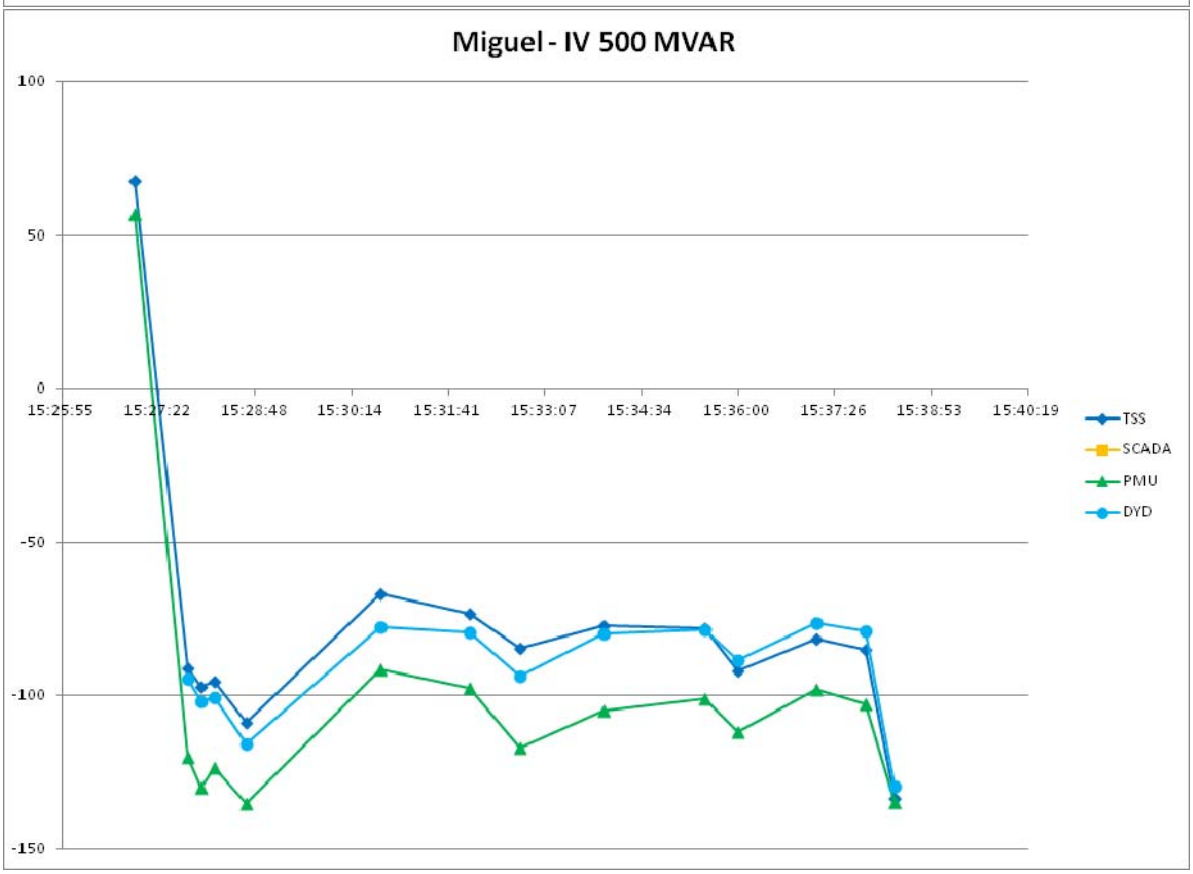

IID SOUTH 92 POCKET MW
200
180
160
140
120
100
80
60
40
20
0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

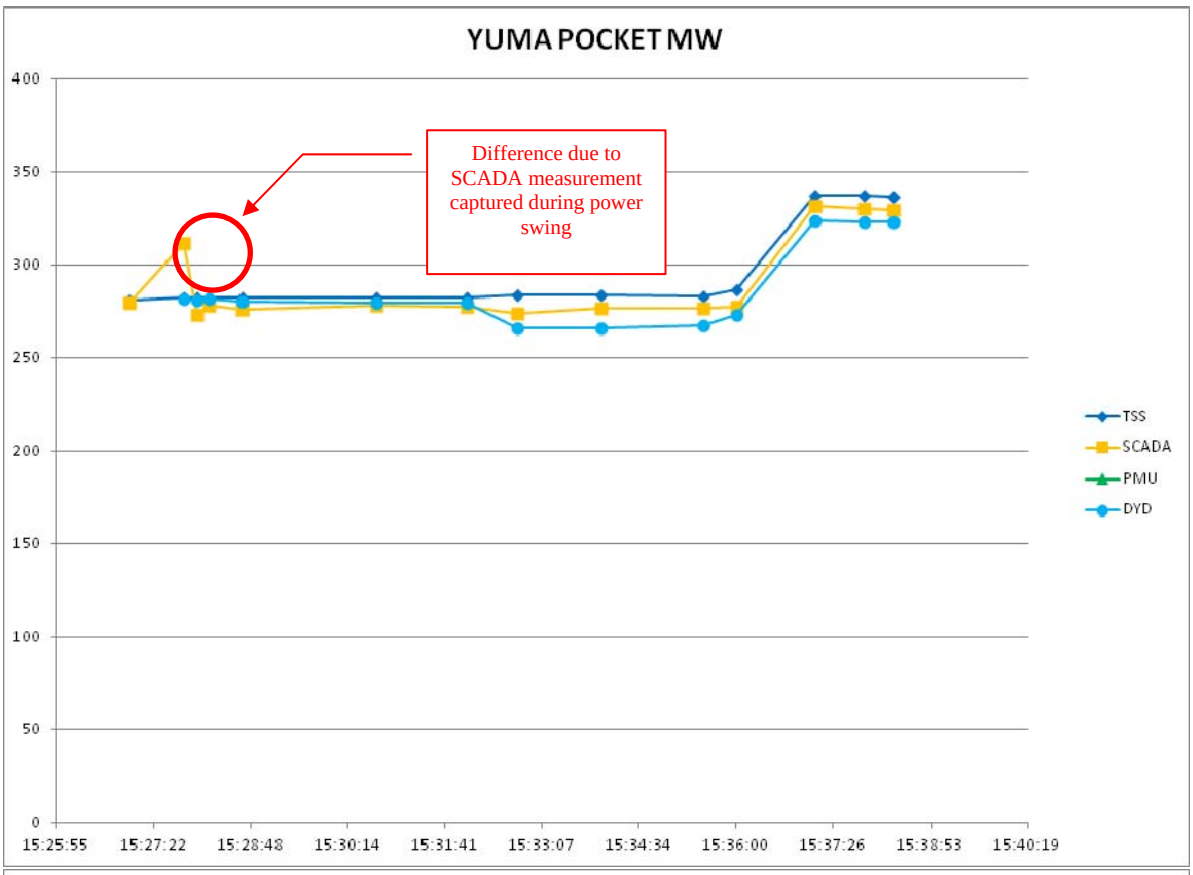

IID SOUTH 92 POCKET MVAR
80
60
40
20
0
-20
-40
-60
-80
-100
-120
-140
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

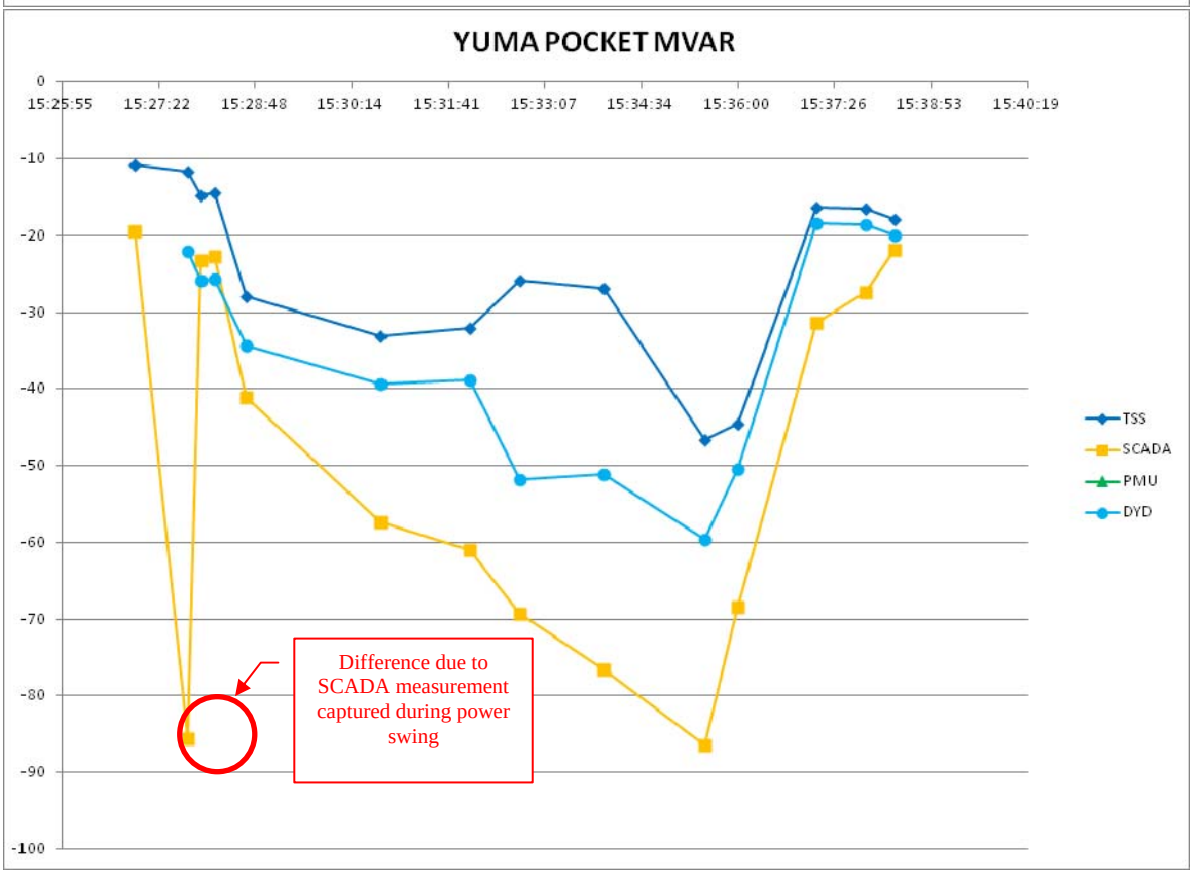

IV - El Centro 230 MW
250
200
150
100
50
0
-50
-100
-150
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

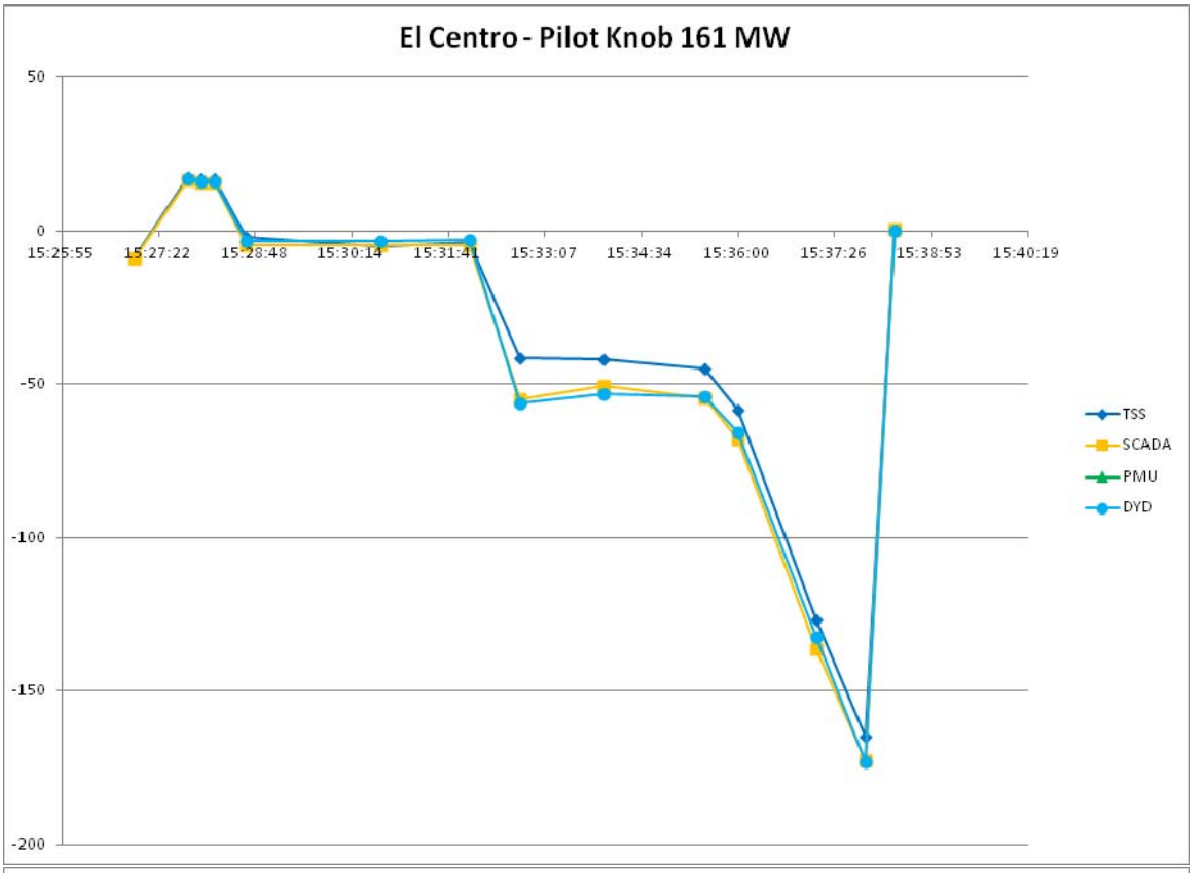

IV - El Centro 230 MVAR
80
60
40
20
0
-20
-40
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

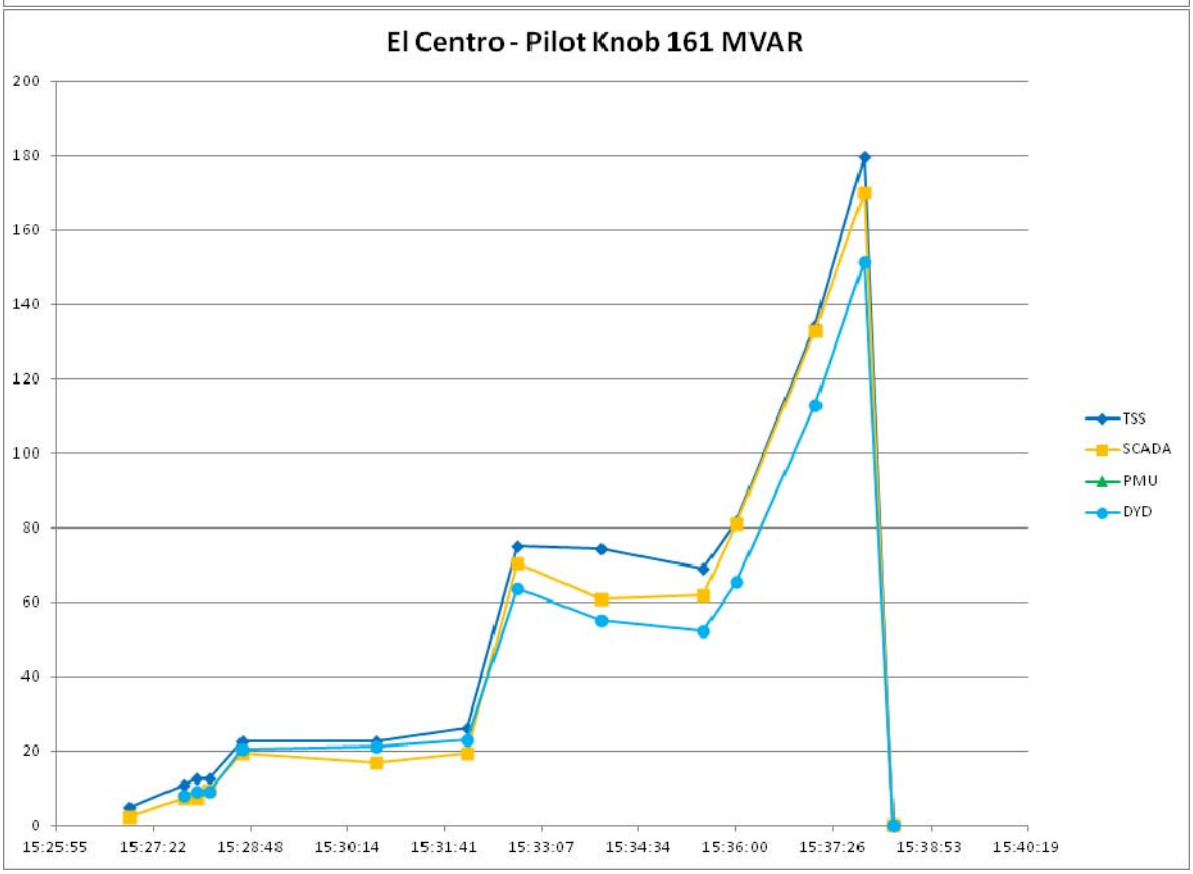

Miguel - IV 500 MW
600
400
200
0
-200
-400
-600
-800
-1000
-1200
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

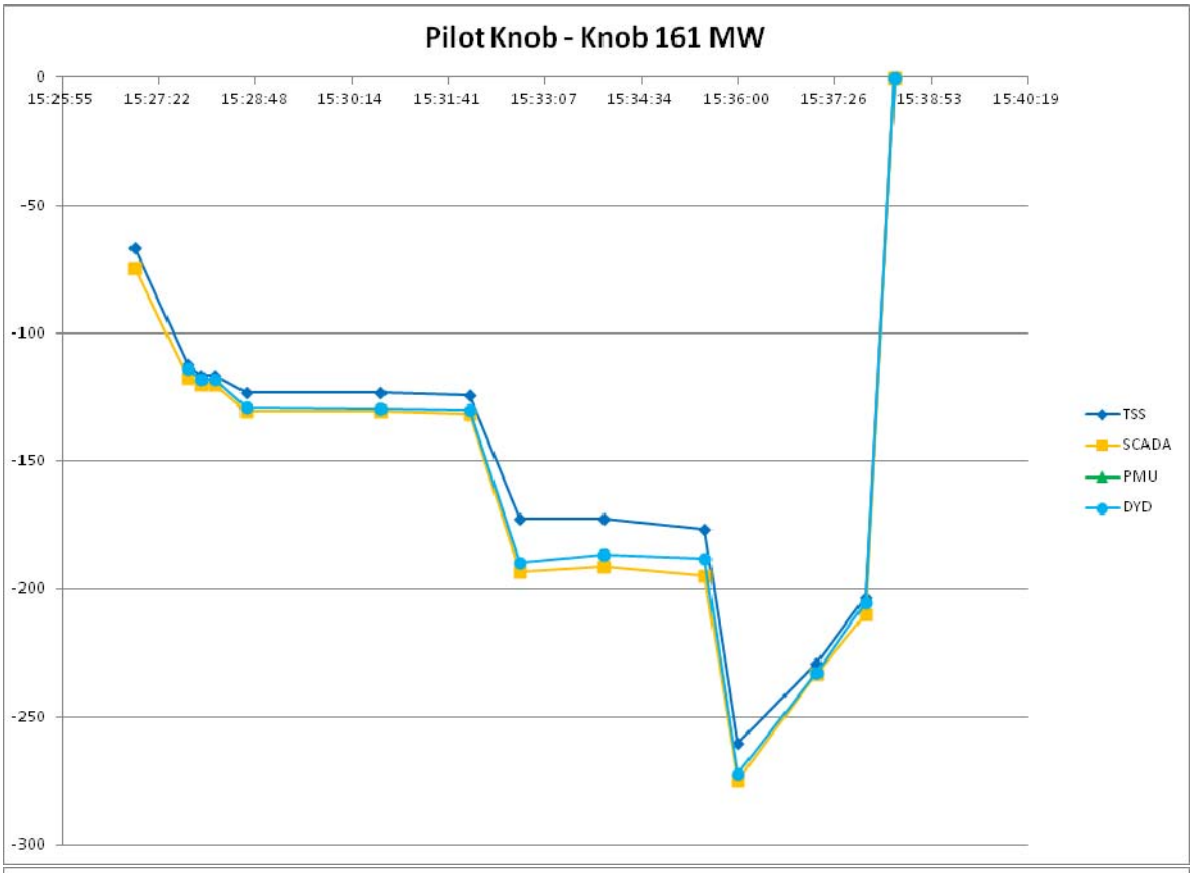

Miguel - IV 500 MVAR
100
50
0
-50
-100
-150
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

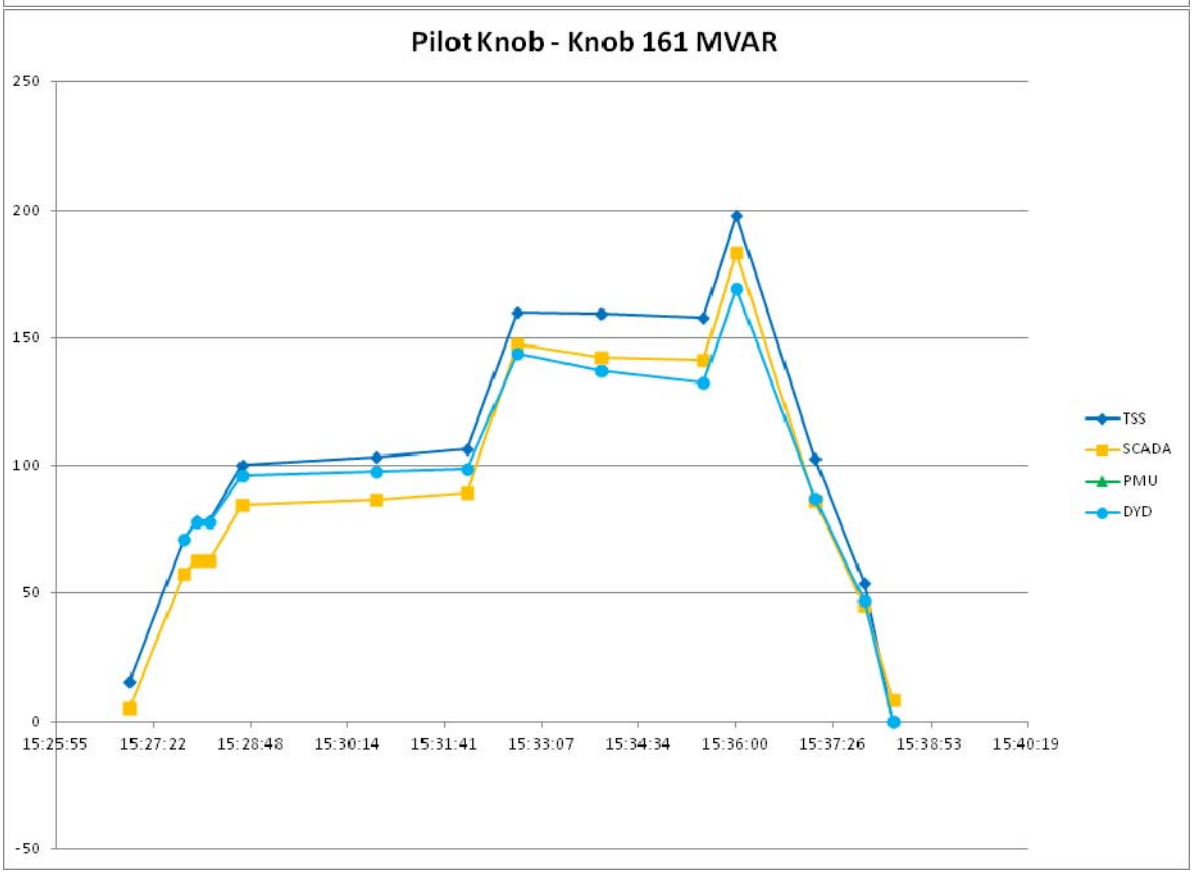

YUMA POCKET MW
Difference due to SCADA measurement captured during power swing
400
350
300
250
200
150
100
50
0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

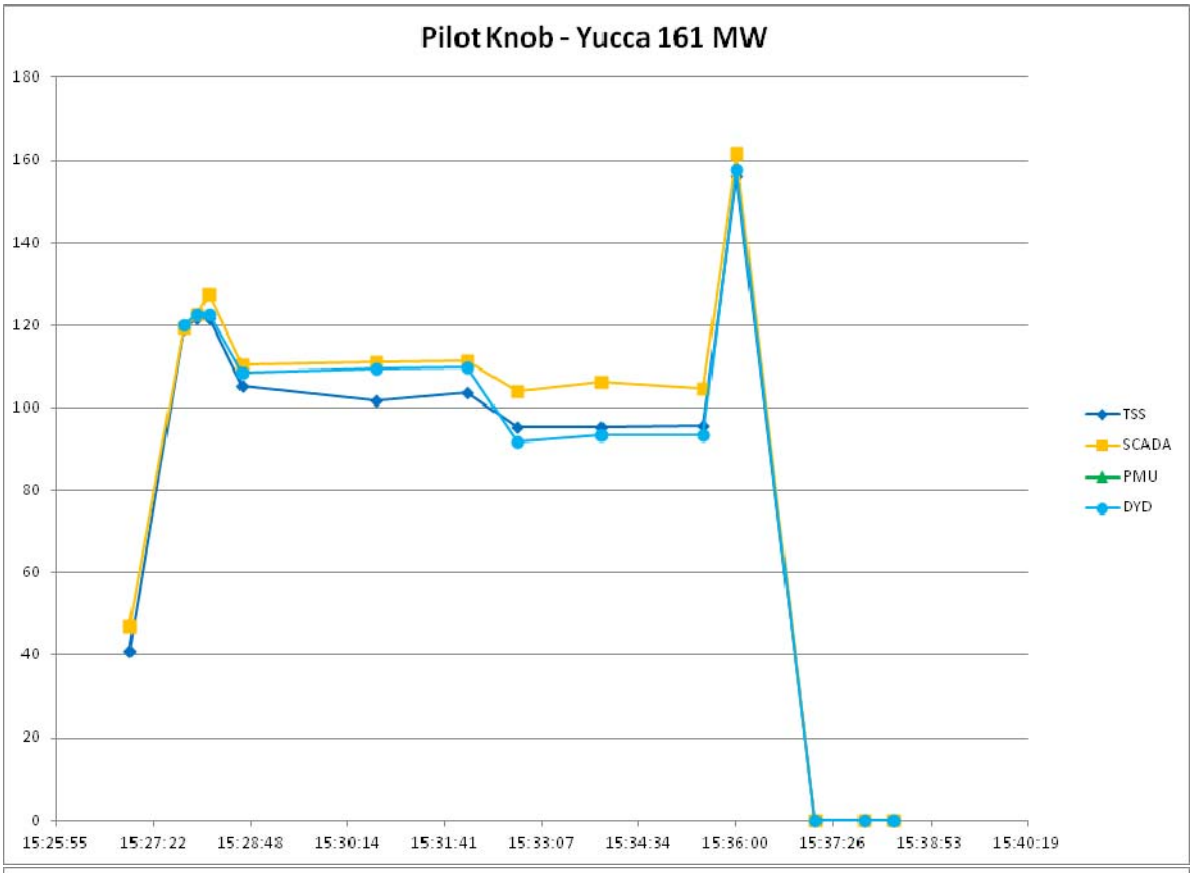

YUMA POCKET MVAR
0
-10
-20
-30
-40
-50
-60
-70
-80
-90
-100
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
Difference due to SCADA measurement captured during power swing
TSS
SCADA
PMU
DYD

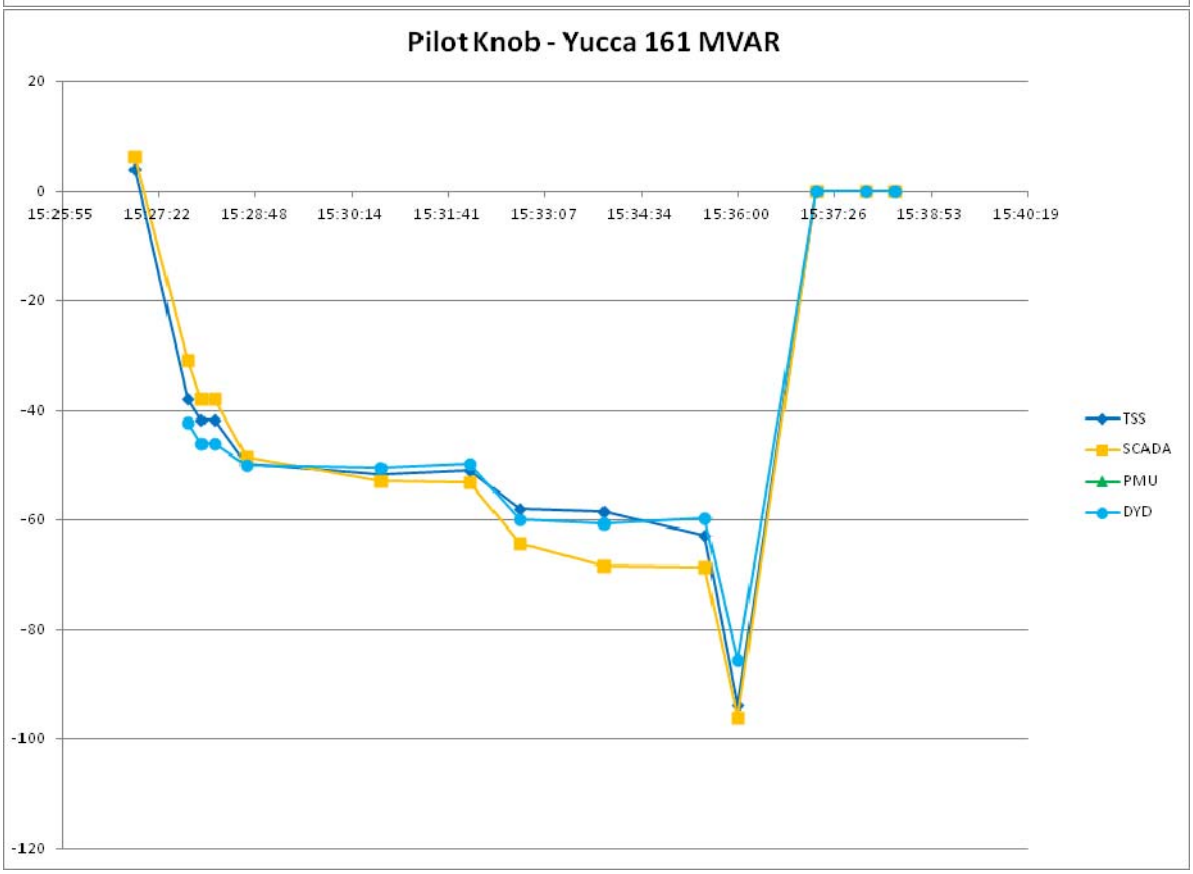

El Centro - Pilot Knob 161 MW
50
0
-50
-100
-150
-200
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

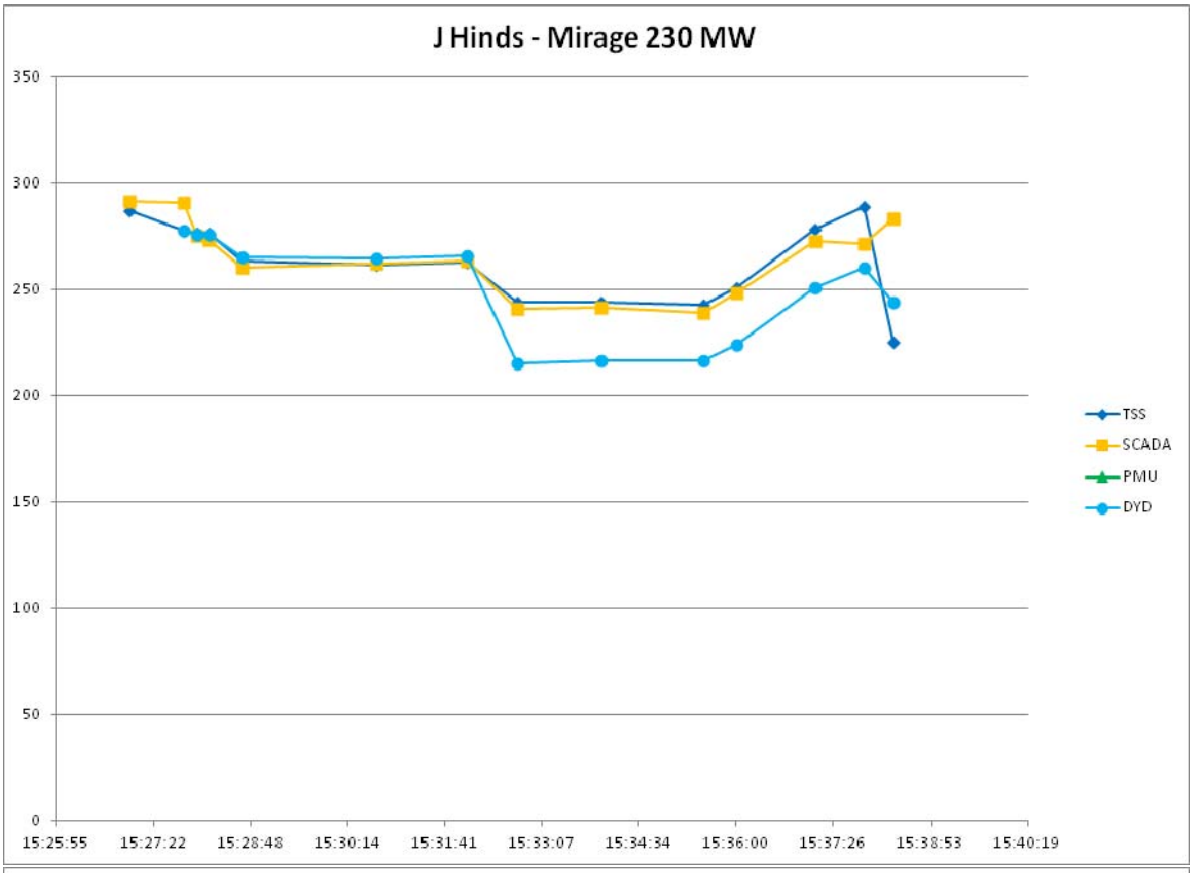

El Centro - Pilot Knob 161 MVAR
200
180
160
140
120
100
80
60
40
20
0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

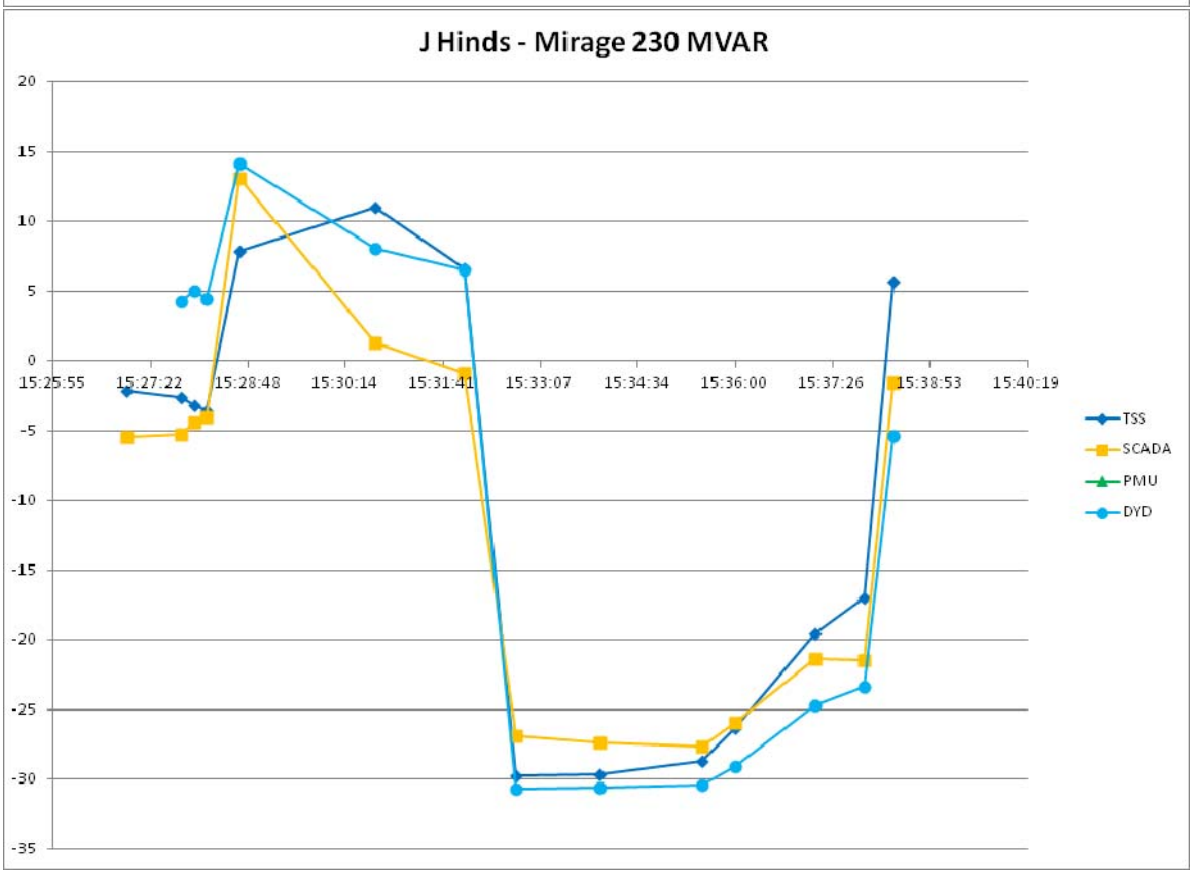

Pilot Knob - Knob 161 MW
0
-50
-100
-150
-200
-250
-300
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

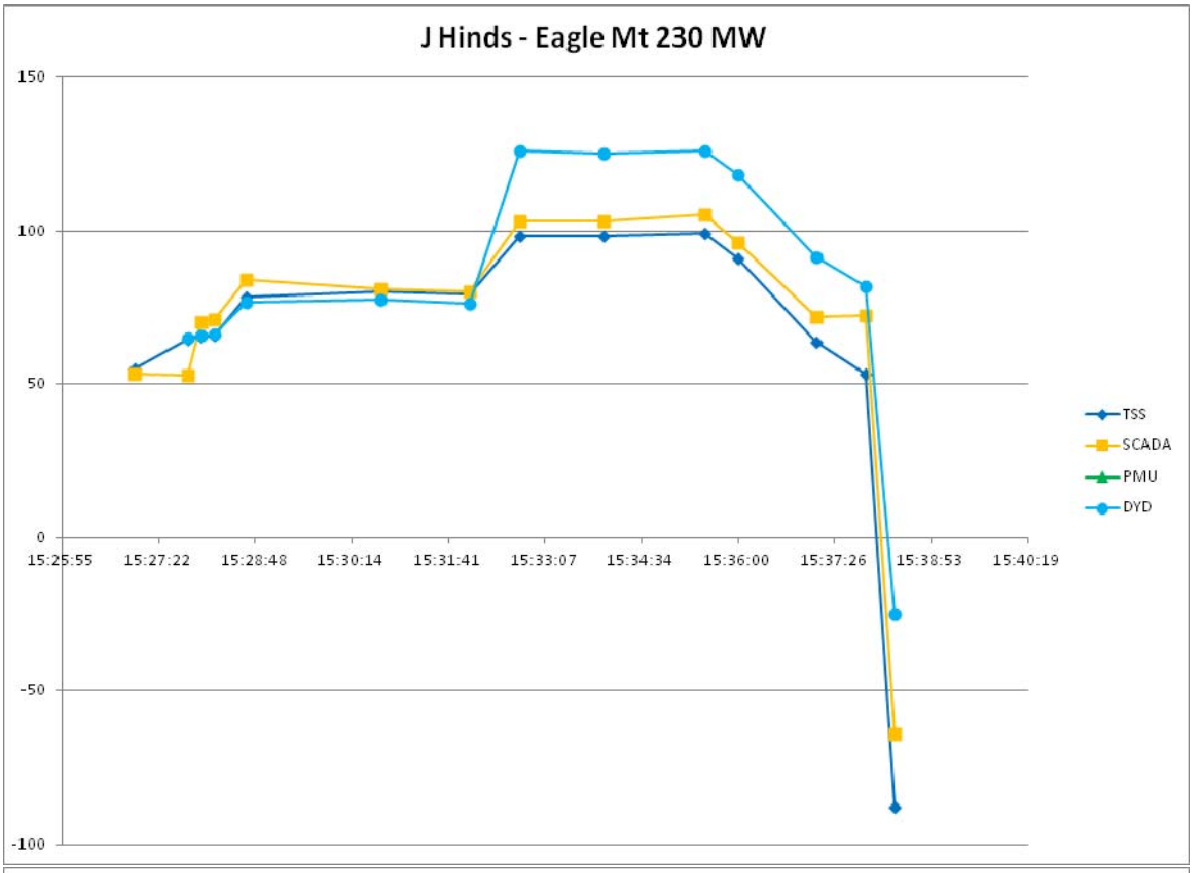

Pilot Knob - Knob 161 MVAR
250
200
150
100
50
0
-50
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

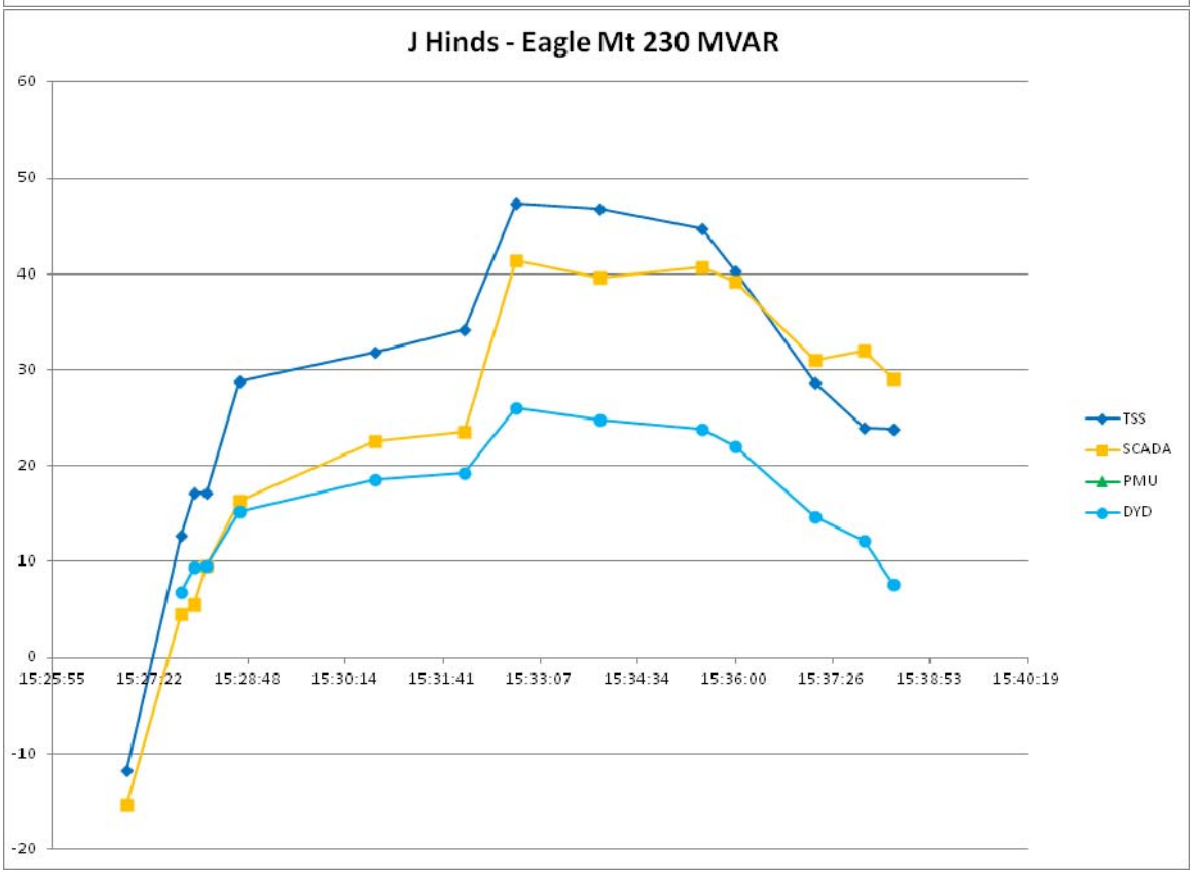

Pilot Knob - Yucca 161 MW
180
160
140
120
100
80
60
40
20
0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD


Pilot Knob - Yucca 161 MVAR
20
0
-20
-40
-60
-80
-100
-120
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD


J Hinds - Mirage 230 MW
350
300
250
200
150
100
50
0
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD


J Hinds - Mirage 230 MVAR
20
15
10
5
0
-5
-10
-15
-20
-25
-30
-35
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD


J Hinds - Eagle Mt 230 MW
150
100
50
0
-50
-100
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD


J Hinds - Eagle Mt 230 MVAR
60
50
40
30
20
10
0
-10
-20
15:25:55
15:27:22
15:28:48
15:30:14
15:31:41
15:33:07
15:34:34
15:36:00
15:37:26
15:38:53
15:40:19
TSS
SCADA
PMU
DYD

Key facilities and interfaces in the affected area were generally benchmarked to within 5% or 10 MVA accuracy to the measured data.

| | | Base Case | | | | | 15:28:11 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Key Facility/ Interface** | **Type** | **Measured** | **Power Flow Simulation** | **Delta (Value)** | **Delta (%)** | | **Measured** | **Power Flow Simulation** | **Delta (Value)** | **Delta (%)** | **Dynamics Simulation** |
| WECC Path 44 | **MVA** | **1310.25** | **1323.61** | **-13.36** | **-1.02%** | | **2453.57** | **2471.50** | **-17.93** | **-0.73%** | **2457.19** |
| | MW | 1296.85 | 1292.09 | 4.77 | 0.37% | | 2434.48 | 2452.40 | -17.92 | -0.74% | 2442.90 |
| | MVAR | -186.93 | -287.17 | 100.24 | -53.63% | | -305.49 | -306.68 | 1.19 | -0.39% | -264.64 |
| Southwest California Desert Imports | **MVA** | **1328.45** | **1336.38** | **-7.93** | **-0.60%** | | **333.50** | **349.91** | **-16.41** | **-4.92%** | **347.90** |
| | MW | 1301.35 | 1307.75 | -6.40 | -0.49% | | 310.76 | 316.68 | -5.92 | -1.90% | 310.03 |
| | MVAR | 266.96 | 275.16 | -8.19 | -3.07% | | -121.02 | -148.82 | 27.80 | -22.97% | -157.84 |
| IID North 92 kV System | **MVA** | **475.15** | **476.81** | **-1.66** | **-0.35%** | | **416.84** | **480.17** | **-63.32**[115] | **-15.19%**[116] | **466.78** |
| | MW | 471.60 | 473.23 | -1.63 | -0.35% | | 414.58 | 477.61 | -63.04 | -15.21% | 464.39 |
| | MVAR | -58.01 | -58.31 | 0.30 | -0.52% | | -43.43 | -49.46 | 6.03 | -13.88% | -47.15 |
| Niland - Blythe 161 kV Line | **MVA** | **67.49** | **69.45** | **-1.97** | **-2.92%** | | **108.41** | **118.34** | **-9.93** | **-9.16%** | **117.37** |
| | MW | -65.13 | -65.99 | 0.86 | -1.32% | | -96.10 | -100.93 | 4.83 | -5.02% | -101.43 |
| | MVAR | 17.68 | 21.67 | -3.99 | -22.56% | | 50.17 | 61.79 | -11.62 | -23.16% | 59.07 |
| IID South 92 kV System | **MVA** | **105.60** | **110.97** | **-5.37** | **-5.08%** | | **114.63** | **132.43** | **-17.80**[117] | **-15.53%**[118] | **124.85** |
| | MW | 104.67 | 110.91 | -6.24 | -5.96% | | 106.14 | 114.84 | -8.70 | -8.20% | 108.87 |
| | MVAR | -14.03 | -3.73 | -10.30 | 73.42% | | -43.29 | -65.93 | 22.65 | -52.31% | -61.12 |
| Imperial Valley - El Centro 230 kV Line ("S" Line) | **MVA** | **96.08** | **105.20** | **-9.12** | **-9.49%** | | **125.31** | **119.52** | **5.79** | **4.62%** | **302.90** |
| | MW | 94.24 | 104.76 | -10.53 | -11.17% | | -109.22 | -101.41 | -7.81 | 7.15% | 302.90 |
| | MVAR | -18.75 | -9.58 | -9.17 | 48.89% | | 61.42 | 63.26 | -1.83 | -2.98% | 0.05 |
| Miguel - Imperial Valley 500 kV Line | **MVA** | **1088.80** | **1095.22** | **-6.42** | **-0.59%** | | **225.19** | **214.12** | **11.07** | **4.91%** | **77.98** |
| | MW | -1087.30 | -1093.10 | 5.80 | -0.53% | | -188.50 | -191.82 | 3.32 | -1.76% | 77.31 |
| | MVAR | 57.18 | 68.13 | -10.94 | -19.14% | | -123.20 | -95.15 | -28.05 | 22.77% | -10.26 |
| Yuma Pocket | **MVA** | **280.78** | **281.61** | **-0.83** | **-0.30%** | | **279.55** | **283.18** | **-3.63** | **-1.30%** | **282.79** |
| | MW | 280.11 | 281.41 | -1.30 | -0.46% | | 278.63 | 282.81 | -4.18 | -1.50% | 281.63 |
| | MVAR | -19.46 | -10.70 | -8.76 | 45.00% | | -22.66 | -14.46 | -8.20 | 36.20% | -25.68 |

**115** Large differences due to SCADA measurement errors at Coachella Valley and Ramon

**116** Id.

**117** The team experienced difficulty in calibrating the MVAR flows in this area, but are generally confident in the benchmarking because the MW values are within 10 MW. The MVA differences in the model appear to increase during this event. The representation of the system in this area of the model appears to assume that the IID South 92 kV system is a load serving local network. However, the actual transmission system operates in parallel with the rest of the BPS. It was difficult to calibrate the flows at the 92 kV to 161 kV interfaces because of the differences between the representation of the system in the model versus the parallel nature of the actual system.

**118** Id.

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| El Centro - Pilot Knob 161 kV Line | **MVA** | **9.15** | **9.83** | **-0.69** | **-7.51%** | | **18.27** | **21.17** | **-2.90** | **-15.87%** | **18.51** |
| | MW | -8.90 | -8.60 | -0.30 | 3.40% | | 15.73 | 17.04 | -1.31 | -8.33% | 16.10 |
| | MVAR | 2.09 | 4.76 | -2.68 | -127.99% | | 9.29 | 12.56 | -3.27 | -35.17% | 9.14 |
| Pilot Knob - Knob 161 kV Line | **MVA** | **74.27** | **68.50** | **5.77** | **7.76%** | | **135.67** | **140.14** | **-4.46** | **-3.29%** | **141.54** |
| | MW | -74.06 | -66.62 | -7.44 | 10.05% | | -120.25 | -116.14 | -4.11 | 3.42% | -118.13 |
| | MVAR | 5.54 | 15.94 | -10.40 | -187.80% | | 62.83 | 78.42 | -15.59 | -24.81% | 77.96 |
| Pilot Knob - Yucca 161 kV Line | **MVA** | **47.34** | **41.17** | **6.18** | **13.05%** | | **132.82** | **128.54** | **4.28** | **3.22%** | **130.96** |
| | MW | 46.92 | 40.94 | 5.98 | 12.74% | | 127.39 | 121.67 | 5.72 | 4.49% | 122.63 |
| | MVAR | 6.33 | 4.30 | 2.03 | 32.04% | | -37.60 | -41.46 | 3.87 | -10.28% | -45.95 |
| Julian Hinds - Mirage 230 kV Line | **MVA** | **291.92** | **287.50** | **4.42** | **1.51%** | | **273.49** | **276.69** | **-3.21** | **-1.17%** | **276.32** |
| | MW | 291.87 | 287.49 | 4.38 | 1.50% | | 273.46 | 276.67 | -3.21 | -1.18% | 276.29 |
| | MVAR | -5.45 | -2.12 | -3.33 | 61.10% | | -3.98 | -3.48 | -0.49 | 12.43% | 4.45 |
| Julian Hinds - Eagle Mountain 230 kV Line | **MVA** | **55.47** | **56.59** | **-1.12** | **-2.01%** | | **71.70** | **68.07** | **3.63** | **5.06%** | **66.96** |
| | MW | 53.29 | 55.35 | -2.07 | -3.88% | | 71.06 | 65.89 | 5.18 | 7.28% | 66.26 |
| | MVAR | -15.43 | -11.78 | -3.64 | 23.62% | | 9.56 | 17.13 | -7.57 | -79.17% | 9.64 |

# Appendix E: Inquiry Team Members

## FERC Staff

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Eric Allen
Greg Henry
James Merlo
Jim Griffith
Jim Robinson
Jule Tate
Kimberly Mielcarek
Mark Vastano
Phil Tatro
Phil Winston (Technical Consultant, from Southern Company)
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# FACT SHEET

May 1, 2012
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Kimberly Mielcarek, NERC (202) 644-8058

## Major Findings and Recommendations: Southwest Power Outage, September 8, 2011

The Joint Inquiry found weaknesses in two broad areas: operations planning and real-time situational awareness.

**Finding – Failure to Update External Networks in Next-Day Study Models**
When conducting next-day studies, some affected transmission operators use models for external networks that are not updated to reflect next-day operating conditions external to their systems.
**Recommendation:** Transmission operators and balancing authorities should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems. The reliability coordinator, transmission operators and balancing authorities should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data.

**Finding – Lack of Real-Time External Visibility**
Affected transmission operators have limited real-time visibility outside their systems, causing a lack of adequate situational awareness.
**Recommendation:** Transmission operators should engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems.

**Finding – Impact of Sub-100 kV Facilities on BPS Reliability**
WECC reliability coordinator and affected transmission operators and balancing authorities do not consistently recognize the adverse impact sub-100 kV facilities can have on bulk power system reliability.
**Recommendation:** WECC, transmission operators and balancing authorities should ensure that all facilities that can adversely impact bulk power system reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies.

**Finding – Failure to Recognize Interconnection Reliability Operating Limits and Establish Valid System Operating Limits**
The cascading nature of the September 8th event indicates that an Interconnection Reliability Operating Limit (IROL) was violated, even though WECC did not recognize any in effect on that day, and that System Operating Limits (SOL) on Path 44 and Hassayampa-North Gila were not valid for the system on September 8, 2011
**Recommendation:** WECC should recognize that IROLs do exist on its system and therefore study them in the day-ahead timeframe and monitor potential situations where IROLs would be exceeded in real-time. WECC should specifically consider whether Path 44 and Hassayampa-North Gila are IROLs since cascading occurred while they were being operated well within their SOLs.

**Finding – Failure to Study and Coordinate Special Protection Systems**
Several transmission operators failed to properly coordinate Special Protection Systems with other protection schemes, resulting in undesirable impacts on system reliability. At the time of the event, WECC did not require two of the System Protection Systems operating on September 8 to be studied.
**Recommendation:** Transmission owners and operators, generation owners and operators, and reliability coordinators should study and coordinate Special Protection Systems and Remedial Action Schemes, evaluate whether such systems are still effective or necessary, and determine if such systems have adverse or unintended effects on reliability.

**Federal Energy Regulatory Commission**

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# FACT SHEET

May 1, 2012
**Contacts:** Mary O'Driscoll, FERC (202) 502-8680
Kimberly Mielcarek, NERC (202) 644-8058

## Sequence of Events: Southwest Power Outage, September 8, 2011

**Phase 1: Before the outage**
Timing: Before Hassayampa-North Gila transmission line (H-NG) trips at 15:27:39

- A hot, shoulder season day with some generation and transmission maintenance outages
- Relatively high loading on some key facilities: H-NG at 78% of its normal rating, Coachella Valley (CV) transformers at 83%
- 44 minutes before loss of H-NG, Imperial Irrigation District (IID)'s real time contingency analysis (RTCA) results show that the N-1 contingency loss of one Coachella Valley (CV) transformer would result in the overload of the second CV transformer beyond its trip point. IID did not act on this RTCA result.
- Arizona Public Service (APS) technician skipped a critical step in isolating the capacitor bank, causing H-NG to trip

**Phase 2**
Timing: 15:27:39 to 15:28:16, just before CV transformer No. 2 trips

- H-NG trips due to fault; APS operators believe they will restore it quickly and notify Western Electricity Coordinating Council (WECC) Reliability Coordinator (RC)
- H-NG flow redistributed to Path 44 transmission line (84% increase in flow), IID (12% of all H-NG flow goes to IID's 92 kV system), and Western Area Power Authority-Lower Colorado (WALC) systems
- Both CV transformers immediately overloaded above their relay setting
- At end of Phase 2, loading on Path 44 at 5,900 out of 8,000 amps needed to initiate San Onofre Nuclear Generating Station (SONGS) separation scheme

**Phase 3**
Timing: 15:28:16, when CV transformer bank No. 2 tripped, to just before 15:32:10, when Ramon transformer tripped

- Both CV transformers tripped within 40 seconds of H-NG tripping
- IID knew losing both CV transformers would overload Ramon transformer and S Line connecting it with San Diego Gas & Electric (SDG&E)
- Severe low voltage in WALC's 161 kV system
- At end of Phase 3, loading on Path 44 at 6,700 amps out of 8,000 needed to initiate SONGS separation scheme

**Phase 4**
Timing: 15:32:10 to just before 15:35:40

- IID's Ramon 230/92 transformer tripped at 15:32:10, was set for 207% of its normal rating instead of 120% as IID had intended, which allowed it to last approximately four minutes longer than CV transformers
- IID experienced undervoltage load shedding, generation and transmission line loss in its 92 kV system

- Path 44 loading increased from approximately 6,700 amps, to as high as 7,800 amps, and ended at around 7,200 amps (out of 8,000 needed to initiate the SONGS separation scheme)

**Phase 5**
Timing: 15:35:40 to just before 15:37:55
- The Gila and Yucca transformers tripped, isolating the Yucca load pocket to a single tie with SDG&E
- Path 44 loading increased from 7,200 to 7,400 amps after Gila transformer tripped, and ended at 7,800 amps after loss of the Yucca transformers and Yuma Cogeneration Associates generator (very close to the 8,000 amps needed to initiate the SONGS separation scheme)

**Phase 6**
Timing: 15:37:55 to 15:38:21.2
- IID's El Centro-Pilot Knob line tripped, forcing all of IID's southern 92 kV system to draw from SDG&E via the S Line
- S Line Remedial Action Scheme (RAS), a type of protection system, operates, tripping generation at Imperial Valley and worsening the loading on Path 44
- S Line RAS trips S Line, isolating IID from SDG&E
- Path 44 exceeds trip point of 8,000 amps, to as high as 9,500 amps
- SONGS separation scheme operates, creates an island composed of SDG&E, Comisión Federal de Electricidad (Baja California, Mexico) (CFE), and APS's Yuma load pocket

**Phase 7**
Timing: Just after 15:38:21.2 to 15:38:38
- Underfrequency Load Shedding (UFLS) could not prevent the SDG&E/CFE/Yuma island from collapsing due to generators tripping during load shedding and frequency decline below generator underfrequency protection settings
- SONGS nuclear units shut down even though they had been isolated to the SCE side of the SONGS separation scheme

**Effects**
- SDG&E lost 4,293 Megawatts (MW) of firm load, affecting approximately 1.4 million customers
- CFE lost 2,205 MW of firm load, affecting approximately 1.1 million customers
- IID lost 929 MW of firm load, affecting approximately 146,000 customers
- APS lost 389 MW of firm load, affecting approximately 70,000 customers
- WALC lost 74 MW of firm load, the majority of which affected APS's customers

**Restoration**
- None of the affected entities were required to use "black start" plans (which work to energize systems using internal generation to get from shutdown to operating condition without assistance from the BES) because they all were able to access sources of power from their own or a neighbor's system that was still energized.
- The restoration process generally proceeded as expected, and some entities restored load more quickly than they had expected.

**Federal Energy Regulatory Commission**

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# News Release

May 1, 2012
**Contacts:** Mary O'Driscoll, FERC (202) 502-8680
Kimberly Mielcarek, NERC (202) 644-8058

## FERC-NERC Staff Report on September 2011 Blackout Calls for Improved Planning

Staff of the Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) today said the September 2011 blackout that left 2.7 million customers in Southern California, Arizona and Baja California without power stemmed from operating in an unsecured state due to inadequate planning and a lack of observability and awareness of system operating conditions on the day of the event.

A joint FERC-NERC staff report on the Sept. 8 blackout, issued today after a nearly eight-month inquiry, recommends that transmission operators and balancing authorities improve how they plan for operations to account for the status of facilities outside their individual systems, the effect of external operations on their own systems and how operation of transmission facilities under 100 kiloVolts (kV) can affect the reliability of the bulk power system.

"This report highlights the growing need for more coordination of grid operations in the West," FERC Chairman Jon Wellinghoff said. "Implementing the recommendations in this report will assist in enhancing the planning and system awareness measures that are necessary to operate an efficiently integrated bulk power system, and reduce costs to consumers from these types of outages that could continue if operational efficiencies are not improved."

"This event underscores how complex and interdependent our North American electric systems are and the critical importance of information sharing, communications, system studies and coordinated operations among all interconnected systems," said Gerry Cauley, president and CEO of NERC. "Transmission operators, Balancing Authorities and Reliability Coordinators must work together to effectively manage this complex system. I would like to recognize the effective collaboration between FERC and NERC staff during the course of this inquiry"

"Today's report provides a series of lessons learned from the September 2011 event that is available to industry for use as a tool to improve their operations and planning of the grid," FERC Commissioner John Norris said. "My hope is that the findings and recommendations in this report will be utilized to the broadest extent possible in order to enhance the reliability and efficiency of the Bulk Power System."

The inquiry was initiated to determine how the blackout occurred and to make recommendations to avoid similar situations in the future. FERC and NERC staff used on-site interviews, sophisticated computer modeling, event simulations and system analysis to make the determination that entities responsible for planning, operating and monitoring the bulk power system were not prepared to ensure reliable operation or prevent cascading outages in the event of a single contingency: the loss of Arizona Public Service's (APS) Hassayampa-North Gila 500 kV transmission line.

That line loss itself did not cause the blackout, but it did initiate a sequence of events that led to the blackout, exposing grid operators' lack of adequate real-time situational awareness of conditions throughout the Western Interconnection. More effective review and use of information would have helped operators avoid the cascading blackout. For example, had operators reviewed and heeded their Real Time Contingency Analysis results prior to the loss of the APS line, they could have taken corrective actions, such as dispatching additional generation or shedding load, to prevent a cascading outage.

The report recommends that bulk power system operators improve their situational awareness through improved communication, data sharing and the use of real-time tools. It also recommends that:

- System planners and operators recognize, study and incorporate the effects of sub-100 kV systems on bulk power system reliability into their planning and operations;
- The Western Electricity Coordinating Council (WECC) recognize and study Interconnection reliability operating limits;
- Transmission Owners and Operators review overload protection relay settings to give them more time to mitigate overloads;
- Transmission Operators and WECC study the effects of special protection systems, remedial action schemes and safety nets, such as the one that disconnected San Diego from the high voltage lines south of the San Onofre Nuclear Generating Station, to understand how they affect reliability and to ensure that they do not have unintended or undesirable effects; and
- System operators plan and account for phase angle differences in order to be able to re-energize transmission lines following outages.

JR12-1

(30)

**Federal Energy Regulatory Commission**

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# STATEMENT

May 1, 2012
**Contacts:** Mary O'Driscoll, FERC (202) 502-8680
Kimberly Mielcarek, NERC (202) 383-2622

## Arizona-Southern California Outages on September 8, 2011
## Prepared Remarks of Heather Polzin, FERC Lead

On behalf of the Inquiry team, I am pleased to announce the issuance today of a report by a joint FERC-NERC Inquiry team on the power outages that affected San Diego, the Imperial Irrigation District, Yuma, Arizona, and Baja California, Mexico, on September 8, 2011. This report describes what happened and explains why approximately 2.7 million electric customers lost service that day. The report also includes 27 recommendations to help industry operators prevent similar outages in the future.

The Inquiry team was composed of members from NERC (my fellow lead Dave Nevius is here with us) and three Commission offices. The team began work the day after the outages, and issued detailed data requests, made site visits, interviewed witnesses, compiled a precise sequence of events, constructed and validated a detailed modeling case, and ran multiple power flow and dynamic stability analyses using the modeling case. The team reviewed over 20 gigabytes of data to support the detailed findings and recommendations in the report.

We've all heard that the outage began with a single 500 kV line, the Hassayampa to North Gila, tripping during maintenance work. That's true. But the bulk electric system is required to be operated so that the loss of a single line, or the occurrence of any other single contingency, such as loss of a generator or a transformer, does not result in instability, uncontrolled separation or cascading. This is known as the "N-1" criterion. What happened on September 8 was that the system was not being operated in that manner. A single contingency occurred (the loss of Hassayampa – North Gila) and it resulted in instability, uncontrolled separation and cascading.

System operators use "system operating limits" or "SOLs" to operate the system within the N-1 criterion. If SOLs are set correctly, operating within the SOLs will satisfy the N-1 criterion. But on September 8, system operators were operating well within important SOLs like those for the Hassayampa-North Gila and for Path 44, which is 5 230 kV lines south of the SONGS nuclear plant. Path 44 is important because a protection system that measured the amperage on Path 44 (the SONGS separation scheme) activated and cut San Diego off from all 5 of those lines, leading to the blackout seconds later. Interconnection reliability limits (IROLs )are SOLs that, if violated, could expose a widespread area of the system to instability, uncontrolled separation or cascading outages. Because of the instability, uncontrolled separation and cascading outages seen on September 8, SOLs were incorrectly set and/or IROLs existed.

After the Hassayampa-North Gila line tripped, all of the power that had been flowing on it (1,391 MW) instantaneously redistributed throughout the system. The increased flow immediately overloaded 230/92 kV transformers at Coachella Valley in the Imperial Irrigation District (IID). These transformers were intended to serve IID's local customers. However, IID's system (as well as that of its neighbor, Western Area Power Administration-Lower Colorado (WALC)), is "in parallel" with, or experiences loop flows from, 2 high voltage power corridors: the Southwest Power Link (SWPL), which includes Hassayampa-North Gila, to the south, and Path 44, to the north. Loop flow and parallel path flow refer to power flowing along transmission paths that are in parallel with the most direct geographic or contract path. Because IID and WALC lie between and are

interconnected with these high-voltage power corridors (SWPL and Path 44), they are forced to carry additional power flow when one of those paths is interrupted. For example, on September 8, approximately 12% of the flow from Hassayampa-North Gila ended up on IID's 92 kV system.

Increased flow on lower-voltage systems, combined with lower-than-peak generation, a hot day and peak demand (evening peak begins at 3 pm), created voltage deviations and equipment overloads which had a ripple effect. It was worsened by the action of protection systems, which take automatic actions that are intended to isolate certain electrical system components in the case of faults, overloads or other unusual system conditions. On September 8, even though protection systems operated as designed, they made matters worse, which calls into question whether they were properly designed, studied or coordinated.

The report makes the following key findings and recommendations:

- Studies used by transmission operators to plan for the next day don't accurately reflect next-day operating conditions outside their system. For example, several transmission operators did not know that over 600 MW of generation in a key location was out for maintenance and did not reflect this in their planning studies. We recommend that transmission operators and the balancing authorities responsible for ensuring that demand and resources are balanced get the necessary data and update their studies to reflect operating conditions external to their system. The reliability coordinator, Western Electricity Coordinating Council (WECC), may need to help encourage and enable data sharing.
- The transmission operators had limited real-time visibility outside their systems, causing a lack of situational awareness. They should engage in more real-time data-sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems. For example, entities other than the owner of the Hassayampa-North Gila 500 kV line generally weren't aware that the line had tripped in real time, even though its loss affected their systems, and many entities weren't aware of the status of IID's Coachella Valley transformers, even though their loss affected the bulk electric systems of others.
- Throughout the areas of the Western Interconnection that we examined, entities did not consistently recognize the impact that facilities below 100 kV could have on the reliability of the bulk power system. The Coachella Valley transformers, as 230/92 kV transformers, are viewed as being below 100 kV and therefore not considered part of the bulk electric system. This means they are not studied or monitored as they would be if they were considered part of the bulk electric system. We recommend that WECC, the regional reliability entity, work with all the other entities to ensure that all sub-100 kV facilities that can adversely impact the reliability of the bulk power system are either designated as part of the bulk electric system, or otherwise incorporated into planning and operations studies and actively monitored and alarmed in real-time contingency analysis (RTCA) systems.
- As discussed above, either SOLs were incorrectly set or IROLs existed on September 8. We recommend that WECC study IROLs in the day-ahead timeframe and monitor IROLs in real-time. In the past, WECC has taken the position that IROLs do not exist in the Western Interconnection as long as entities are operating under conditions they have studied. The September 8 event calls this philosophy into question. WECC does have a proposed new procedure (effective in June) to begin identifying and monitoring IROLs.
- There were several instances of protection systems not being studied or coordinated. Protection systems, including the SONGS separation scheme and the S Line RAS, played a key role in worsening system conditions after the Hassayampa-North Gila line tripped. Before October 2011, WECC did not generally require several types of protection systems to be studied. We recommend that transmission owners and operators, generation owners and operators, and the WECC reliability coordinator work together to study and coordinate protection systems, especially the SONGS separation scheme and the S Line RAS, evaluate whether they are still effective and necessary, and determine if they have adverse or unintended effects on reliability.

I'd now like to turn to my fellow Inquiry Lead, NERC Senior Vice President Dave Nevius, for his remarks. After that, we'll be happy to take your questions.

**From:** Joanne M. Rura
**To:** Joanne M. Rura
**Subject:** FERC-NERC September 2011 Outage Report Calls for Improved Planning
**Date:** Tuesday, May 01, 2012 2:04:13 PM
**Importance:** High

# Media Release

## FERC-NERC September 2011 Outage Report Calls for Improved Planning

**Click here for the Release**
**Click here for the Report**

**WASHINGTON, DC –** The September 2011 blackout that left 2.7 million consumers in Southern California, Arizona and Baja California without power stemmed from operating in an unsecure state due to inadequate planning and a lack of observability and awareness of system operating conditions on the day of the event, a joint report by the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) found.

The report was released today after a nearly eight-month inquiry and recommends that transmission operators and Balancing Authorities improve how they plan for operations to account for the status of facilities outside their individual systems, the effects of external operations on their own systems and how operation of transmission facilities under 100 kV can affect the reliability of the bulk power system.

For more information or assistance, please contact Kimberly Mielcarek.

**3353 Peachtree Road NE**
**Suite 600, North Tower**
**Atlanta, GA 30326**
**404-446-2560 | www.nerc.com**

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| | |
|---|---|
| **From:** | Philip A. Fedora |
| **To:** | rcc; jtfc; Philip Raymond |
| **Subject:** | RE: Southwest outage reports avaiable |
| **Date:** | Tuesday, May 01, 2012 1:35:11 PM |
| **Importance:** | High |

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**May 1, 2012** - FERC-NERC Staff Report on September 2011 Blackout Calls for Improved Planning
News Release | Report | FERC Staff Statement | Fact Sheets: Sequence of Events | Findings & Recommendations

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**From:** Philip A. Fedora
**Sent:** Monday, April 30, 2012 4:27 PM
**To:** rcc; jtfc; Philip Raymond
**Subject:** Fw: Southwest outage call-in

FYI - Don - please distribute to the NYSRC-EC.

Sent from my Verizon Wireless BlackBerry

---

**From:** Kimberly Mielcarek <Kimberly.Mielcarek@nerc.net>
**Date:** Mon, 30 Apr 2012 15:47:21 -0400
**To:** Kimberly Mielcarek<Kimberly.Mielcarek@nerc.net>
**ReplyTo:** Kimberly Mielcarek <Kimberly.Mielcarek@nerc.net>
**Subject:** Southwest outage call-in

All:

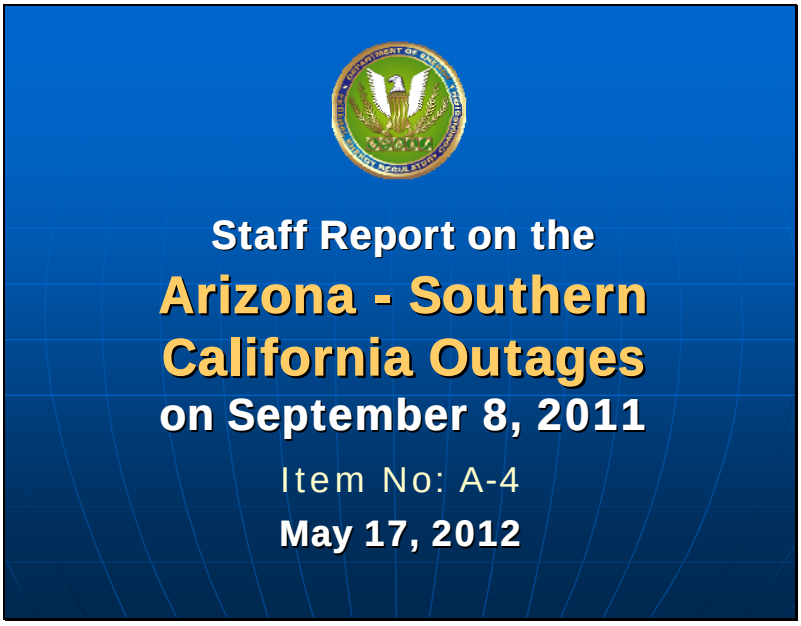
At 1:30 p.m. (EST) tomorrow, FERC and NERC will release the Southwest (Calif.) outage joint report during a press briefing. David Nevius, from NERC, and Heather Polzin, from FERC, will conduct the briefing. Non-press can listen on an audio-only line:

Call in number: 1-800-369-1885
Pass Code: 96533
Leader: MS MARY O'DRISCOLL

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Slide 1



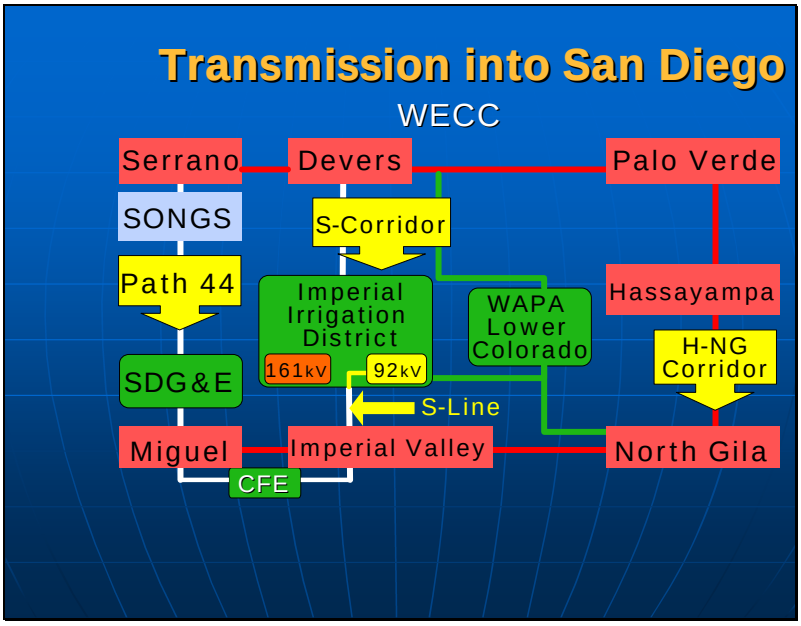

Mr. Chairman, Commissioners, I am pleased to present a summary of the FERC/NERC Staff Report on the September 8, 2011 Blackout. *The presentation is based on conclusions of the staff and not necessarily those of the Commission, the Chairman or any of the individual Commissioners.* This inquiry was truly a collaborative effort, with representation from the Offices of Enforcement, Electric Reliability, Energy Policy & Innovation, and External Affairs. As you know, it was a joint inquiry with the North American Electric Reliability Corporation, and we also had liaisons from the Nuclear Regulatory Commission and Department of Energy. I would also like to ask those who participated in the inquiry to stand and be recognized.

On September 9, 2011, the Commission and NERC announced a joint inquiry into the causes of the widespread, cascading blackout of portions of Arizona, Southern California, and Baja California, Mexico that occurred on September 8, 2011. Approximately 2.7 million customers lost power during the event, including the entirety of San Diego, making the September 8th blackout the largest power failure in California history. The inquiry was completed and its report, published jointly by NERC and the Commission, was released in eight months. We thank NERC for its cooperation and contributions to the inquiry.

The inquiry obtained approximately 20 gigabytes of data from approximately 500 data requests; conducted numerous site visits, meetings, and depositions to gather information from the affected entities; and conducted numerous outreach meetings with members of the electric industry, including the Edison Electric Institute, the North American Transmission Forum, the American Public Power Association and the National Rural Electric Cooperative Association.

I will briefly describe what happened in the 11 minutes before the blackout, and then highlight key findings and recommendations from the inquiry's report.

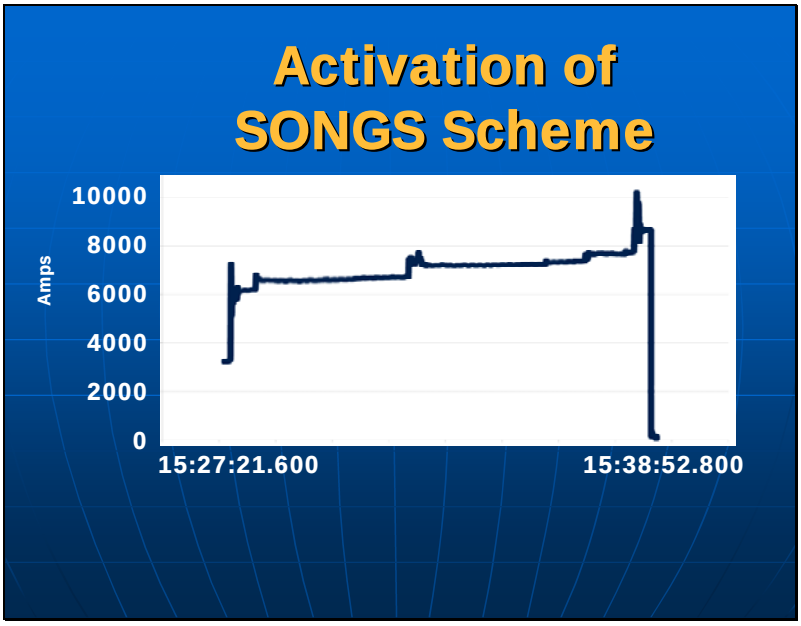
Slide 2




The inquiry determined that the blackout began with the loss of a single facility: Arizona Public Service's 500 kilovolt transmission line from Hassayampa to North Gila. The loss of this line interrupted one of the three major power corridors into the San Diego area, labeled on this simplified diagram as H-NG Corridor, S-Corridor, and Path 44. The red lines represent 500 kilovolt lines, the white lines represent 230 kilovolt lines, and the green lines represent 161 kilovolt lines. When the H-NG Corridor was interrupted, power flows immediately redistributed through lower voltage systems, such as those in the Imperial Irrigation District and WAPA Lower Colorado (shown as the S Corridor), in order to deliver enough power to San Diego on a hot day during hours of peak demand. Flows also redistributed onto the five 230 kilovolt lines that form Path 44, also known as South of San Onofre Nuclear Generating Station, or SONGS, increasing its flow by 84%.

However, the Bulk Electric System is required to be operated in a manner that avoids instability, uncontrolled separation and cascading, even with the occurrence of any single contingency, such as the loss of a generator, transformer or transmission line. This is known as the "N-1 criterion." The fact that the loss of a single transmission line led to cascading demonstrated that on September 8, 2011, the Western Interconnection was not being operated within a secure N-1 state.

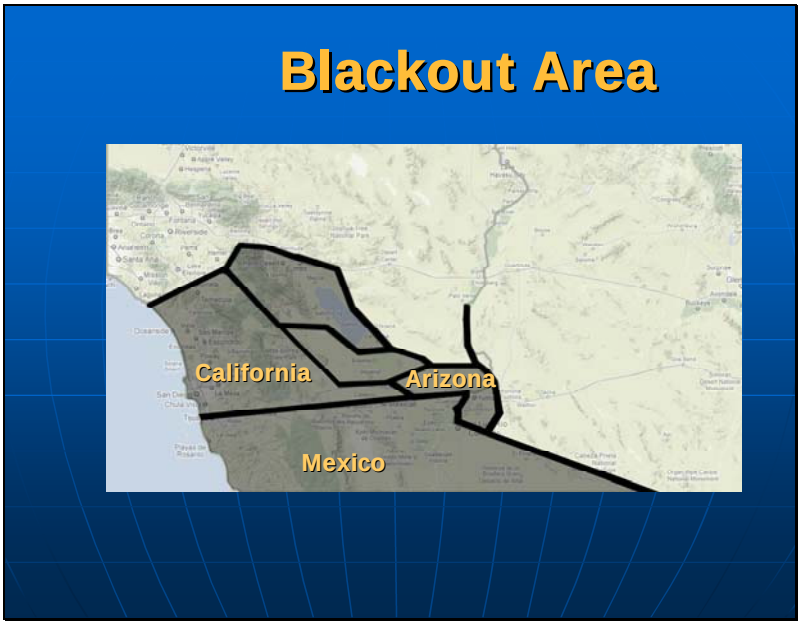
Slide 3




The inquiry divided its sequence of events into seven distinct phases, beginning with the initial trip of the H-NG transmission line and culminating in the initiation of an intertie separation scheme (the SONGS separation scheme) which separated San Diego and Path 44 at SONGS. This slide shows a simplified version of the loading on the five 230 kilovolt lines that form Path 44 (also known as South of Songs). When the aggregate current on Path 44 remained over 8,000 amperes, the SONGS separation scheme would separate San Diego from Path 44. The first spike on this slide resulted from the loss of the Hassayampa-North Gila 500 kV line, and the next two spikes resulted from the loss of below-100-kilovolt transformers in the Imperial Irrigation District.

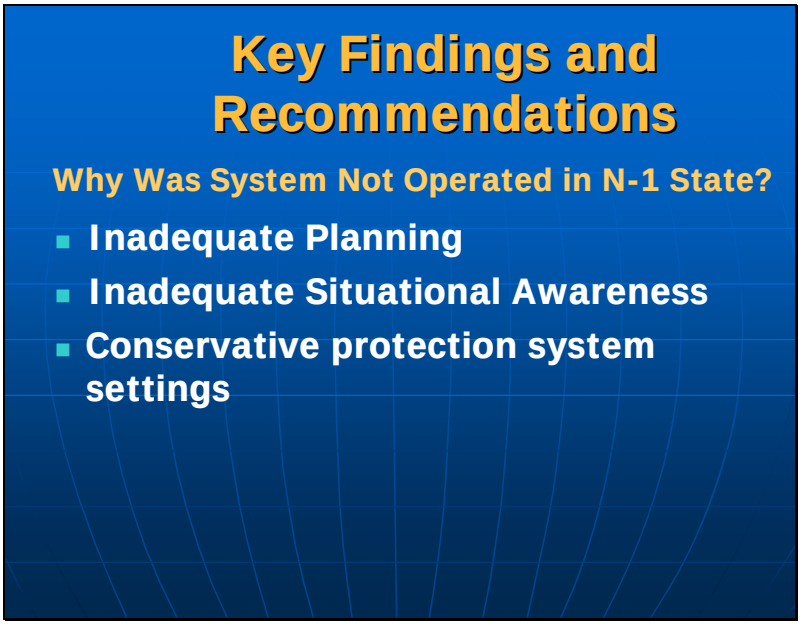
The flow and voltage deviations and resulting overloads that began with the loss of the Hassayampa-North Gila 500 kV line had a ripple effect, as transformers, transmission lines, and generating units tripped offline, most of which had the effect of increasing the loading on Path 44, as seen on this chart. Just seconds before the blackout, Path 44 carried all flows into the San Diego area as well as part of Arizona and Mexico. Eventually, the excessive loading on Path 44 engaged the SONGS separation scheme, separating San Diego from Path 44, causing both SONGS nuclear units to trip offline, and resulting in the complete blackout of San Diego. The time elapsed, from line trip to complete blackout, was approximately 11 minutes.

Slide 4




This slide shows the balancing authority/transmission operator areas affected by the blackout (and the islands into which they separated before the blackout).

Slide 5




The inquiry identified 27 findings and recommendations to prevent the recurrence of events like the September 8th blackout, but we would like to focus on five key areas. Several of these areas of concern were also seen in the 2003 Blackout, namely planning, situational awareness, and protection systems. Appendix C to our report compares the 2003 and San Diego blackouts in these three areas. The following factors help explain why the system was not being operated in an N-1 state, as required.

First, the inquiry determined that, over every planning horizon (operations, short-term and long-term), the planning process in the WECC region lacked effective depth, breadth and coordination. Many of the affected entities' seasonal, next-day, and real-time studies do not adequately consider:

- Operations of facilities in external networks, including transmission outages, generation levels, and load forecasts,
- External contingencies that could impact their systems, or internal contingencies that could impact their neighbors' systems, and
- The impact on Bulk-Power System reliability of internal and external lower-voltage facilities, especially those operated at less than 100 kilovolts.

In order to improve planning in the WECC region, the inquiry recommends that Transmission Operators and Balancing Authorities, as appropriate:

- Obtain information on neighboring entities' operations, including transmission outages, generation levels, load forecasts, and scheduled interchanges,
- Identify and plan for external contingencies that could impact their systems, and
- Consider the impact of sub-100 kilovolt facilities on their systems' reliability.

Second, the inquiry determined that many entities lacked adequate real-time situational awareness of conditions and contingencies throughout the Western interconnection. Many entities' real-time tools, such as Real-Time Contingency Analysis, are restricted by models that do not accurately reflect the status of external

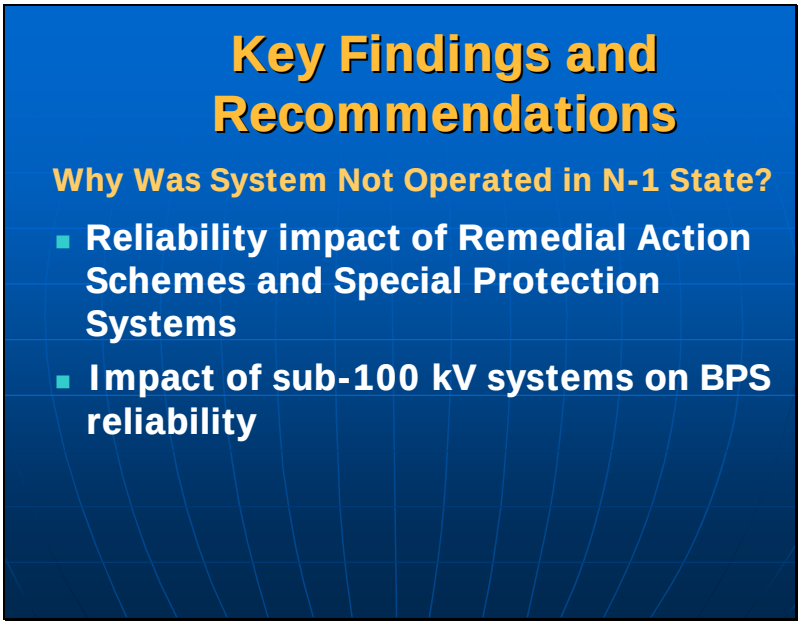
networks. Some entities' real-time tools are also insufficient to alert operators to significant conditions or potential contingencies on their or their neighbors' systems. The lack of adequate situational awareness limits entities' abilities to prevent instability, uncontrolled separation, or cascading outages. The inquiry determined that if some of the affected entities had been aware of real-time external conditions at the time of the event, they would have been better prepared for its impacts and may have avoided the cascading that occurred.

In order to improve the situational awareness of grid operators, the inquiry recommends that entities:

- Expand external visibility in their real-time models through more extensive data sharing with nearby entities,
- Improve the use of real-time tools to ensure constant monitoring for potential contingencies, and
- Improve communications among entities to help maintain situational awareness.

The inquiry also found some significant issues with protection system settings, which contributed to the cascading nature of the event. Some entities set their overload relay trip points for facilities extremely close to those facilities' emergency ratings, resulting in those facilities being automatically removed from service without providing operators enough time to mitigate overloads. The inquiry determined that, had trip points been set to allow for higher loading levels, operators may have had time to mitigate overloads and prevent cascading outages during the event. To avoid a similar problem in the future, the inquiry recommends that Transmission Owners review their facilities' overload protection relay settings. The report suggested PRC-023 as a guideline for relay loadability settings.

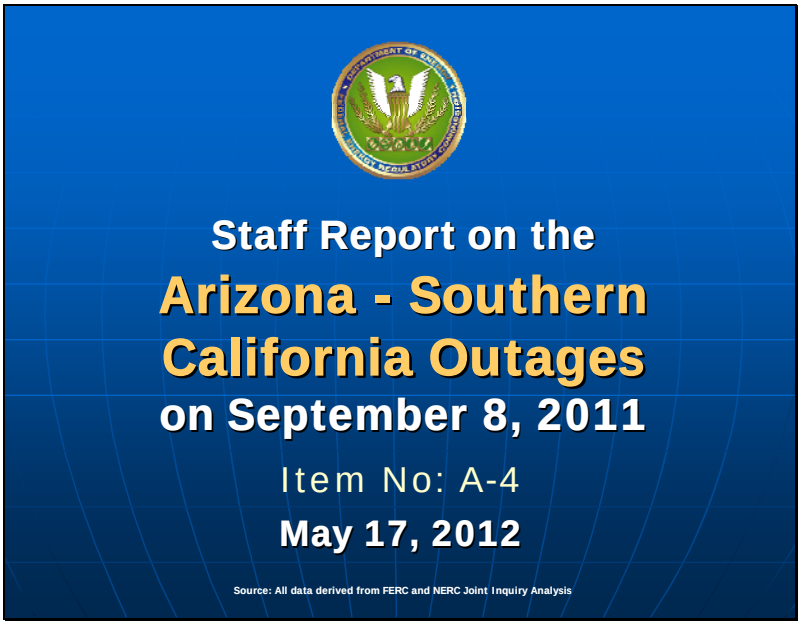
Slide 6




Next, the inquiry determined that entities did not adequately assess and study the reliability impact of special protection systems, remedial action schemes, and safety nets. The operation of one such safety net, the SONGS separation scheme, had a significant impact on BPS reliability, separating San Diego and resulting in the loss of both SONGS nuclear generators. Nevertheless, none of the affected entities, including the owner of the scheme, studied its impact on system reliability, leaving them without a full understanding of the state of their systems during the event. Another special protection system/remedial action scheme (RAS) which operated on September 8th, the S Line RAS, was likewise not sufficiently studied and uncoordinated, and contributed to the cascading nature of the event. The inquiry recommends that all special protection systems and separation schemes, including safety nets, should be studied to understand their impact on system reliability and to ensure their operation does not have unintended or undesirable effects.

Finally, the September 8th event highlights the impact that even low voltage facilities can have on the reliability of the bulk-power system. The inquiry discovered that the WECC Reliability Coordinator and the affected entities do not consistently recognize the adverse impact that sub-100 kilovolt facilities have on BPS reliability, especially lower-voltage facilities which operate in parallel to higher voltage systems. The prevailing System Operating Limits and Path Ratings in the region did not take into account facilities which, although not designated as part of the Bulk Electric System, contributed to and caused the cascading blackouts of September 8, especially three 230/92 kV transformers within the Imperial Irrigation District's footprint. The inquiry determined that if these facilities had been designated as part of the Bulk Electric System or otherwise incorporated into planning and operations studies, and monitored in real time, cascading outages could have been avoided on the day of the event. Accordingly, the inquiry recommends that, regardless of voltage level, facilities that can have an adverse impact on bulk-power system reliability be considered for classification as part of the Bulk Electric System or otherwise studied as part of entities' planning in various time horizons and monitored and alarmed in real time.

Slide 7


Staff Report on the
Arizona - Southern California Outages
on September 8, 2011
Item No: A-4
May 17, 2012
Source: All data derived from FERC and NERC Joint Inquiry Analysis

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Announcement

## New Web-Based Data System Helps Mandatory Collection Efforts

May 3, 2012

**ATLANTA** – The North American Electric Reliability Corporation (NERC) launched a new web-based data collection system that collects information for measuring and monitoring the contributions of electric power plants to the reliability of the bulk power system.

NERC has collected electric generating unit operational data from the industry using the Generating Availability Data System (GADS) since 1982. To increase the value of the information provided on power plant reliability, in August 2011 NERC's Board of Trustees broadened GADS participation to all North American conventional power plants.

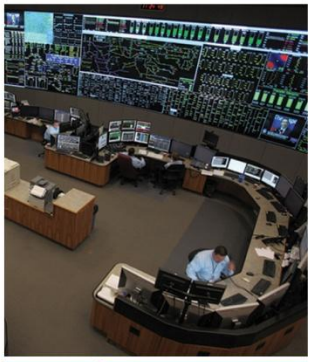
"Statistics from GADS have been an important industry source for information on power plant performance and resource planning for more than three decades," said Mark Lauby, vice president and director of Reliability Assessment and Performance Analysis. "Expanding GADS data collection to all power plants connected to the bulk electric system in North America supports the evolution to an integrated view of overall system and equipment reliability."

The new web-based system will facilitate the data collection process and provide NERC access to vital information needed to evaluate electric generation of the bulk power system in North America. Units with a nameplate rating of 50 MW and larger will begin reporting their information beginning January 1, 2012. For units 20 MW and larger, data collection will begin in 2013.

For more information on GADS, visit the website by clicking here. Visit the NERC website at www.nerc.com.









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**From:** Kimberly Mielcarek
**To:** Kimberly Mielcarek
**Subject:** NERC Announcement - New Web-Based Data System Helps Mandatory Collection Efforts
**Date:** Thursday, May 03, 2012 12:37:59 PM

# Announcement

## New Web-Based Data System Helps Mandatory Collection Efforts

**Click here for announcement**

**ATLANTA** – The North American Electric Reliability Corporation (NERC) launched a new web-based data collection system that collects information for measuring and monitoring the contributions of electric power plants to the reliability of the bulk power system. NERC has collected electric generating unit operational data from the industry using the Generating Availability Data System (GADS) since 1982. To increase the value of the information provided on power plant reliability, in August 2011 NERC's Board of Trustees broadened GADS participation to all North American conventional power plants.

For more information or assistance, please contact Kimberly Mielcarek.

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press release

**EMBARGOED UNTIL 2:00 P.M. ON MAY 4, 2012**

Contact:
Ellen Foley, ISO New England Inc. (413) 535-4139
Marcia Blomberg, ISO New England Inc. (413) 540-4555
Lacey Ryan, ISO New England Inc. (413) 540-4483

# New England's Power Grid Summer Outlook Announced

## *Supplies adequate for summer, but uncertainty regarding fuel supplies could create tight system conditions in Northeast Massachusetts/Greater Boston area during periods of heavy consumer demand*

Holyoke, MA—May 4, 2012—Under normal weather and system conditions, New England's electric power supplies are expected to be adequate to meet regional demand this summer, according to ISO New England Inc., the operator of the region's bulk power system and wholesale electricity markets.

However, reduced and uncertain supplies of liquefied natural gas (LNG) to power generation in the Northeast Massachusetts/Greater Boston area during the summer could create local reliability challenges to that portion of the power grid if extreme summer weather conditions, with high consumer demand, occurs or if unexpected resource outages occur. Under normal weather conditions, all areas of the region's grid should have adequate supply.

"On the regional level, the outlook for power system operations this summer is good," said Vamsi Chadalavada, executive vice president and chief operating officer of ISO New England. "To address the concerns about potential reliability challenges in the Northeast Massachusetts/Boston area, the ISO is working with local generation and transmission companies to develop special operating plans that we can use, if needed, to manage a shortage situation. In addition, the ISO has briefed the appropriate state and federal authorities and is continuously monitoring the situation in NEMA/Boston."

ISO New England has well-established procedures in place to bring the system back into balance if electricity supplies get tight as a result of an unexpected resource outage, or if an extended heat wave causes consumer demand for electricity to spike. These actions could include calling on demand-response resources to curtail their energy use, importing emergency power from neighboring regions, and asking businesses and residents to voluntarily conserve energy.

New England is a summer-peaking system, which means that consumer demand for electricity peaks during the hot summer months, largely because of air-conditioning use. ISO New England forecasts that demand could peak at 27,440 megawatts (MW) under normal summer weather conditions of about

Created in 1997, ISO New England is the independent, not-for-profit corporation responsible for the reliable operation of New England's electric power generation and transmission system, overseeing and ensuring the fair administration of the region's wholesale electricity markets, and managing comprehensive regional electric power planning.

90 degrees Fahrenheit.[1] This forecast reflects the impact of continued slow economic growth on consumer demand. Under extreme weather conditions, such as an extended heat wave with temperatures of 95 degrees or higher, consumer demand could reach 29,620 MW.[2] New England has about 32,800 MW of total capacity that includes generation, demand resources, and imports from neighboring areas.

Last year, an extended heat wave in the region pushed electricity demand up to 27,707 MW on July 22, just shy of the all-time record for peak demand of 28,130 MW set on August 2, 2006. In New England, one megawatt of electricity can power approximately 1,000 homes.

[1] When the impact of passive demand resources (energy-efficiency measures) is factored in, the forecasted peak under normal summer weather conditions is reduced to 26,462 MW.

[2] When the impact of passive demand resources is factored in, the forecasted peak under extreme summer weather conditions is reduced to 28,642 MW.

**Created in 1997, ISO New England is the independent, not-for-profit corporation responsible for the reliable operation of New England's electric power generation and transmission system, overseeing and ensuring the fair administration of the region's wholesale electricity markets, and managing comprehensive regional electric power planning.**

I

112TH CONGRESS
1ST SESSION

# H. R. 3674

To amend the Homeland Security Act of 2002 to make certain improvements in the laws relating to cybersecurity, and for other purposes.

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IN THE HOUSE OF REPRESENTATIVES

DECEMBER 15, 2011

Mr. DANIEL E. LUNGREN of California (for himself, Mr. KING of New York, Mr. MCCAUL, Mr. BILIRAKIS, Mrs. MILLER of Michigan, Mr. WALBERG, Mr. MARINO, Mr. LONG, Mr. TURNER of New York, Mr. STIVERS, and Mr. LANGEVIN) introduced the following bill; which was referred to the Committee on Homeland Security, and in addition to the Committees on Oversight and Government Reform, Science, Space, and Technology, the Judiciary, and Select Intelligence (Permanent Select), for a period to be subsequently determined by the Speaker, in each case for consideration of such provisions as fall within the jurisdiction of the committee concerned

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# A BILL

To amend the Homeland Security Act of 2002 to make certain improvements in the laws relating to cybersecurity, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

**SECTION 1. SHORT TITLE.**

This Act may be cited as the ''Promoting and Enhancing Cybersecurity and Information Sharing Effectiveness Act of 2011'' or the ''PRECISE Act of 2011''.

**SEC. 2. DEPARTMENT OF HOMELAND SECURITY CYBERSECURITY ACTIVITIES.**

(a) IN GENERAL.—Subtitle C of title II of the Homeland Security Act of 2002 is amended by adding at the end the following new sections:

**''SEC. 226. NATIONAL CYBERSECURITY AUTHORITY.**

''(a) IN GENERAL.—To protect Federal systems and critical infrastructure information systems and to prepare the Nation to respond to, recover from, and mitigate against acts of terrorism and other incidents involving such systems and infrastructure, the Secretary shall—

''(1) develop and conduct risk assessments for Federal systems and, upon request and subject to the availability of resources, critical infrastructure information systems in consultation with the heads of other agencies or governmental and private entities that own and operate such systems, that may include threat, vulnerability, and impact assessments and penetration testing, or other comprehensive assessments techniques;

''(2) foster the development, in conjunction with other governmental entities and the private sector, of essential information security technologies and capabilities for protecting Federal systems and critical infrastructure information systems, including com-

prehensive protective capabilities and other technological solutions;

''(3) acquire, integrate, and facilitate the adoption of new cybersecurity technologies and practices in a technologically and vendor-neutral manner to keep pace with emerging terrorist and other cybersecurity threats and developments, including through research and development, technical service agreements, and making such technologies available to governmental and private entities that own or operate critical infrastructure information systems, as necessary to accomplish the purpose of this section;

''(4) maintain the capability to serve as a focal point with the Federal Government for cybersecurity, responsible for—

''(A) the coordination of the protection of Federal systems and critical infrastructure information systems;

''(B) the coordination of national cyber incident response;

''(C) facilitating information sharing, interactions, and collaborations among and between Federal agencies, State and local governments, the private sector, academia, and international partners;

''(D) working with appropriate Federal agencies, State and local governments, the private sector, academia, and international partners to prevent and respond to terrorist and other cybersecurity threats and incidents involving Federal systems and critical infrastructure information systems pursuant to the national cyber incident response plan and supporting plans developed in accordance with paragraph (8);

''(E) the dissemination of timely and actionable terrorist and other cybersecurity threat, vulnerability, mitigation, and warning information, including alerts, advisories, indicators, signatures, and mitigation and response measures, to improve the security and protection of Federal systems and critical infrastructure information systems;

''(F) the integration of information from Federal Government and non-federal network operation centers and security operations centers;

''(G) the compilation and analysis of information about risks and incidents regarding terrorism or other causes that threaten Federal

systems and critical infrastructure information systems;

''(H) the provision of incident prediction, detection, analysis, mitigation, and response information and remote or on-site technical assistance to heads of Federal agencies and, upon request, governmental and private entities that own or operate critical infrastructure; and

''(I) acting as the Federal Government representative with the organization or organizations designated under section 241;

''(5) assist in national efforts to mitigate communications and information technology supply chain vulnerabilities to enhance the security and the resiliency of Federal systems and critical infrastructure information systems;

''(6) develop and lead a nationwide awareness and outreach effort to educate the public about—

''(A) the importance of cybersecurity and cyber ethics;

''(B) ways to promote cybersecurity best practices at home and in the workplace; and

''(C) training opportunities to support the development of an effective national cybersecu-

rity workforce and educational paths to cybersecurity professions;

''(7) establish, in coordination with the Director of the National Institute of Standards and Technology and the heads of other appropriate agencies, benchmarks and guidelines for making critical infrastructure information systems more secure at a fundamental level, including through automation, interoperability, and privacy-enhancing authentication;

''(8) develop a national cybersecurity incident response plan and supporting cyber incident response and restoration plans, in consultation with the heads of other relevant Federal agencies, owners and operators of critical infrastructure, sector coordinating councils, State and local governments, and relevant non-governmental organizations and based on applicable law that describe the specific roles and responsibilities of governmental and private entities during cyber incidents to ensure essential government operations continue;

''(9) develop and conduct exercises, simulations, and other activities designed to support the national response to terrorism and other cybersecurity threats and incidents and evaluate the national

cyber incident response plan and supporting plans developed in accordance with paragraph (8);

''(10) ensure that the technology and tools used to accomplish the requirements of this section are scientifically and operationally validated; and

''(11) take such other lawful action as may be necessary and appropriate to accomplish the requirements of this section.

''(b) COORDINATION.—

''(1) COORDINATION WITH OTHER ENTITIES.—In carrying out the cybersecurity activities under this section, the Secretary shall coordinate, as appropriate, with—

''(A) the head of any relevant agency or entity;

''(B) representatives of State and local governments;

''(C) the private sector, including owners and operators of critical infrastructure;

''(D) suppliers of technology for critical infrastructure;

''(E) academia; and

''(F) international organizations and foreign partners.

''(2) COORDINATION OF AGENCY ACTIVITIES.—The Secretary shall coordinate the activities undertaken by agencies to protect Federal systems and critical infrastructure information systems and prepare the Nation to predict, anticipate, recognize, respond to, recover from, and mitigate against risk of acts of terrorism and other incidents involving such systems and infrastructure.

''(3) LEAD CYBERSECURITY OFFICIAL.—The Secretary shall designate a lead cybersecurity official to provide leadership to the cybersecurity activities of the Department and to ensure that the Department's cybersecurity activities under this subtitle are coordinated with all other infrastructure protection and cyber-related programs and activities of the Department, including those of any intelligence or law enforcement components or entities within the Department.

''(4) REPORTS TO CONGRESS.—The lead cybersecurity official shall make regular reports to the appropriate committees of Congress on the coordination of cyber-related programs across the Department.

''(c) STRATEGY.—In carrying out the cybersecurity functions of the Department, the Secretary shall develop and maintain a strategy that—

''(1) articulates the actions necessary to assure the readiness, reliability, continuity, integrity, and resilience of Federal systems and critical infrastructure information systems;

''(2) is informed by the need to maintain economic prosperity and facilitate market leadership for the United States information and communications industry; and

''(3) protects privacy rights and preserves civil liberties of United States persons.

''(d) ACCESS TO INFORMATION.—The Secretary shall ensure that the organization or organizations designated under section 241 have full and timely access to properly anonymized cyber incident information originating within the Federal civilian networks to populate the common operating picture described in section 242.

''(e) NO RIGHT OR BENEFIT.—The provision of assistance or information to governmental or private entities that own or operate critical infrastructure information systems under this section shall be at the discretion of the Secretary and subject to the availability of resources. The provision of certain assistance or information to one gov-

ernmental or private entity pursuant to this section shall not create a right or benefit, substantive or procedural, to similar assistance or information for any other governmental or private entity.

''(f) SAVINGS CLAUSE.—Nothing in this subtitle shall be interpreted to alter or amend the law enforcement or intelligence authorities of any agency.

''(g) DEFINITIONS.—In this section:

''(1) The term 'Federal systems' means all information systems owned, operated, leased, or otherwise controlled by an agency, or on behalf of an agency, except for national security systems or those information systems under the control of the Department of Defense.

''(2) The term 'critical infrastructure information systems' means any physical or virtual information system that controls, processes, transmits, receives, or stores electronic information in any form, including data, voice, or video, that is—

''(A) vital to the functioning of critical infrastructure as defined in section 5195c(e) of title 42; or

''(B) owned or operated by or on behalf of a State or local government entity that is nec-

essary to ensure essential government operations continue.

**''SEC. 227. IDENTIFICATION OF SECTOR SPECIFIC CYBERSECURITY RISKS.**

''(a) IN GENERAL.—The Secretary shall, on a continuous and sector-by-sector basis, identify and evaluate cybersecurity risks to critical infrastructure. In carrying out this subsection, the Secretary shall coordinate, as appropriate, with the following:

''(1) The head of the sector specific agency with responsibility for critical infrastructure.

''(2) The head of any agency with responsibilities for regulating the critical infrastructure.

''(3) The owners and operators of critical infrastructure and any private sector entity determined appropriate by the Secretary.

''(b) EVALUATION OF RISKS.—The Secretary, in coordination with the individuals and entities referred to in subsection (a), shall evaluate the cybersecurity risks identified under subsection (a) by taking into account each of the following:

''(1) The actual or assessed threat, including a consideration of adversary capabilities and intent, preparedness, target attractiveness, and deterrence capabilities.

''(2) The extent and likelihood of death, injury, or serious adverse effects to human health and safety caused by a disruption, destruction, or unauthorized use of critical infrastructure.

''(3) The threat to national security caused by the disruption, destruction or unauthorized use of critical infrastructure.

''(4) The harm to the economy that would result from the disruption, destruction, or unauthorized use of critical infrastructure.

''(5) Other risk-based security factors that the Secretary, in consultation with the head of the sector specific agency with responsibility for critical infrastructure and the head of any Federal agency that is not a sector specific agency with responsibilities for regulating critical infrastructure, and in consultation with any private sector entity determined appropriate by the Secretary to protect public health and safety, critical infrastructure, or national and economic security.

''(c) AVAILABILITY OF IDENTIFIED RISKS.—The Secretary shall ensure that the risks identified and evaluated under this section for each sector and subsector are made available to the owners and operators of critical infrastructure within each sector and subsector.

''(d) COLLECTION OF RISK-BASED PERFORMANCE STANDARDS.—

''(1) REVIEW AND ESTABLISHMENT.—The Secretary, in coordination with the heads of other appropriate agencies, shall review existing internationally recognized consensus-developed risk-based performance standards, including such standards developed by the National Institute of Standards and Technology, for inclusion in a common collection. Such collection shall include, for each such risk-based performance standard, an analysis of each of the following:

''(A) How well the performance standard addresses the identified risks.

''(B) How cost-effective the standard implementation of the performance standard can be.

''(2) USE OF COLLECTION.—The Secretary, in conjunction with the heads of other appropriate agencies, shall develop market-based incentives designed to encourage the use of the collection established under paragraph (1).

''(3) INCLUSION IN REGULATORY REGIMES.—The heads of sector specific agencies with responsibility for covered critical infrastructure and the head

of any Federal agency that is not a sector specific agency with responsibilities for regulating covered critical infrastructure, in consultation with the Secretary and with any private sector entity determined appropriate by the Secretary, shall propose through notice and comment rulemaking to include the most effective and cost-efficient risk-based performance standards identified in the collection established under paragraph (1) in the regulatory regimes applicable to covered critical infrastructure.

''(e) MITIGATION OF RISKS.—If the Secretary determines that no existing internationally-recognized risk-based performance standard mitigates a risk identified under subsection (a), the Secretary shall—

''(1) work with owners and operators of critical infrastructure and suppliers of technology to appropriately mitigate the identified risk, including determining appropriate market-based incentives for development and implementation of the identified mitigation; and

''(2) engage with the National Institute of Standards and Technology and appropriate international consensus bodies that develop and strengthen standards and practices to address the identified risk.

''(f) COVERED CRITICAL INFRASTRUCTURE DEFINED.—In this section, the term 'covered critical infrastructure' means any facility or function that, by way of cyber vulnerability, the destruction or disruption of or unauthorized access to could result in—

''(1) a significant loss of life;

''(2) a major economic disruption, including—

''(A) the immediate failure of, or loss of confidence in, a major financial market; or

''(B) the sustained disruption of financial systems that would lead to long term catastrophic economic damage to the United States;

''(3) mass evacuations of a major population center for an extended length of time; or

''(4) severe degradation of national security or national security capabilities, including intelligence and defense functions, but excluding military facilities.

''(g) REDRESS.—

''(1) IN GENERAL.—Subject to paragraphs (2) and (3), the Secretary shall develop a mechanism, consistent with subchapter II of chapter 5 of title 5, United States Code, for an owner or operator notified under subsection (f) to appeal the identification

of a facility or function as covered critical infrastructure under this section.

''(2) APPEAL TO FEDERAL COURT.—A civil action seeking judicial review of a final agency action taken under the mechanism developed under paragraph (1) shall be filed in the United States District Court for the District of Columbia.

''(3) COMPLIANCE.—The owner or operator of a facility or function identified as covered critical infrastructure shall comply with any requirement of this subtitle relating to covered critical infrastructure until such time as the facility or function is no longer identified as covered critical infrastructure, based on—

''(A) an appeal under paragraph (1);

''(B) a determination of the Secretary unrelated to an appeal; or

''(C) a final judgment entered in a civil action seeking judicial review brought in accordance with paragraph (2).

**''SEC. 228. INFORMATION SHARING.**

''(a) CYBERSECURITY INFORMATION.—The Secretary shall be responsible for making all cyber threat information, provided pursuant to section 202 of this title, available to appropriate owners and operators of critical infra-

structure on a timely basis consistent with the responsibilities of the Secretary to provide information related to threats to critical infrastructures to the organization designated under section 241.

''(b) INFORMATION SHARING.—The Secretary shall, to the maximum extent possible, consistent with rules for the handling of classified and sensitive but unclassified information, share relevant information regarding cybersecurity threats and vulnerabilities, and any proposed actions to mitigate them, with all Federal agencies, appropriate State or local government representatives, and appropriate critical infrastructure information systems owners and operators, including by expediting necessary security clearances for designated points of contact for critical infrastructure information systems.

''(c) PROTECTION OF INFORMATION.—The Secretary shall designate, as appropriate, information received from Federal agencies and from critical infrastructure information systems owners and operators and information provided to Federal agencies or critical infrastructure information systems owners and operators pursuant to this section as sensitive security information and shall require and enforce sensitive security information requirements for handling, storage, and dissemination of any such informa-

tion, including proper protections for personally identifiable information.

**''SEC. 229. CYBERSECURITY RESEARCH AND DEVELOPMENT.**

''(a) IN GENERAL.—The Under Secretary for Science and Technology shall support research, development, testing, evaluation, and transition of cybersecurity technology, including fundamental, long-term research to improve the ability of the United States to prevent, protect against, detect, respond to, and recover from acts of terrorism and cyber attacks, with an emphasis on research and development relevant to attacks that would cause a debilitating impact on national security, national economic security, or national public health and safety.

''(b) ACTIVITIES.—The research and development testing, evaluation, and transition supported under subsection (a) shall include work to—

''(1) advance the development and accelerate the deployment of more secure versions of fundamental Internet protocols and architectures, including for the domain name system and routing protocols;

''(2) improve, create, and advance the research and development of techniques and technologies for

proactive detection and identification of threats, attacks, and acts of terrorism before they occur;

''(3) advance technologies for detecting attacks or intrusions, including real-time monitoring and real-time analytic technologies;

''(4) improve and create mitigation and recovery methodologies, including techniques and policies for real-time containment of attacks and development of resilient networks and systems;

''(5) develop and support infrastructure and tools to support cybersecurity research and development efforts, including modeling, test beds, and data sets for assessment of new cybersecurity technologies;

''(6) assist in the development and support of technologies to reduce vulnerabilities in process control systems;

''(7) develop and support cyber forensics and attack attribution;

''(8) test, evaluate, and facilitate the transfer of technologies associated with the engineering of less vulnerable software and securing the information technology software development lifecycle; and

''(9) ensure new cybersecurity technologies are scientifically and operationally validated.

''(c) COORDINATION.—In carrying out this section, the Under Secretary shall coordinate activities with—

''(1) the Under Secretary for National Protection and Programs Directorate; and

''(2) the heads of other relevant Federal departments and agencies, including the National Science Foundation, the Defense Advanced Research Projects Agency, the Information Assurance Directorate of the National Security Agency, the National Institute of Standards and Technology, the Department of Commerce, academic institutions, and other appropriate working groups established by the President to identify unmet needs and cooperatively support activities, as appropriate.

**''SEC. 230. PERSONNEL AUTHORITIES RELATED TO THE OFFICE OF CYBERSECURITY AND COMMUNICATIONS.**

''(a) IN GENERAL.—In order to assure that the Department has the necessary resources to carry out the mission of securing Federal systems and critical infrastructure information systems, the Secretary may, as necessary, convert competitive service positions, and the incumbents of such positions, within the Office of Cybersecurity and Communications to excepted service, or may establish new positions within the Office of Cybersecurity

and Communications in the excepted service, to the extent that the Secretary determines such positions are necessary to carry out the cybersecurity functions of the Department.

''(b) COMPENSATION.—The Secretary may—

''(1) fix the compensation of individuals who serve in positions referred to in subsection (a) in relation to the rates of pay provided for comparable positions in the Department and subject to the same limitations on maximum rates of pay established for employees of the Department by law or regulations; and

''(2) provide additional forms of compensation, including benefits, incentives, and allowances, that are consistent with and not in excess of the level authorized for comparable positions authorized under title 5, United States Code.

''(c) RETENTION BONUSES.—Notwithstanding any other provision of law, the Secretary may pay a retention bonus to any employee appointed under this section, if the Secretary determines that the bonus is needed to retain essential personnel. Before announcing the payment of a bonus under this subsection, the Secretary shall submit a written explanation of such determination to the Committee on Homeland Security of the House of Representa-

tives and the Committee on Homeland Security and Governmental Affairs of the Senate.

''(d) ANNUAL REPORT.—Not later than one year after the date of the enactment of this section, and annually thereafter, the Secretary shall submit to the Committee on Homeland Security of the House of Representatives and the Committee on Homeland Security and Government Affairs of the Senate a detailed report that includes, for the period covered by the report—

''(1) a discussion the Secretary's use of the flexible authority authorized under this section to recruit and retain qualified employees;

''(2) metrics on relevant personnel actions, including—

''(A) the number of qualified employees hired by occupation and grade, level, or pay band;

''(B) the total number of veterans hired;

''(C) the number of separations of qualified employees;

''(D) the number of retirements of qualified employees; and

''(E) the number and amounts of recruitment, relocation, and retention incentives paid

to qualified employees by occupation and grade, level, or pay band; and

''(3) long-term and short-term strategic goals to address critical skills deficiencies, including an analysis of the numbers of and reasons for attrition of employees and barriers to recruiting and hiring individuals qualified in cybersecurity.''.

(b) CLERICAL AMENDMENT.—The table of contents in section 2(b) of such Act is amended by inserting after the item relating to section 225 the following new items:

''Sec. 226. National cybersecurity authority.
''Sec. 227. Identification of sector specific cybersecurity risks.
''Sec. 228. Information sharing.
''Sec. 229. Cybersecurity research and development.
''Sec. 230. Personnel authorities related to the Office of Cybersecurity and Communications.''.

(c) PLAN FOR EXECUTION OF AUTHORITIES.—Not later than 120 days after the date of the enactment of this Act, the Secretary of Homeland Security shall submit to the Committee on Homeland Security of the House of Representatives and the Committee on Homeland Security and Governmental Affairs of the Senate a report containing a plan for the execution of the authorities contained in the amendment made by subsection (a).

**SEC. 3. NATIONAL INFORMATION SHARING ORGANIZATION.**

(a) NATIONAL INFORMATION SHARING ORGANIZATION.—

(1) IN GENERAL.—Title II of the Homeland Security Act of 2002, as amended by section 2, is further amended by adding at the end the following:

# ''Subtitle E—National Information Sharing Organization

## ''SEC. 241. ESTABLISHMENT OF NATIONAL INFORMATION SHARING ORGANIZATION.

''(a) ESTABLISHMENT.—There is established a not-for-profit organization for sharing cyber threat information and exchanging technical assistance, advice, and support and developing and disseminating necessary information security technology. Such organization shall be designated as the 'National Information Sharing Organization'.

''(b) PURPOSE.—The National Information Sharing Organization shall serve as a national clearinghouse for the exchange of cyber threat information so that the owners and operators of networks or systems in the private sector, educational institutions, State, tribal, and local governments, entities operating critical infrastructure, and the Federal Government have access to timely and actionable information in order to protect their networks or systems as effectively as possible.

''(c) DESIGNATION.—Not later than 120 days after the date of the enactment of this subtitle, the board of

directors established in section 243 shall designate the appropriate organization or organizations as the National Information Sharing Organization.

''(d) CRITERIA FOR DESIGNATION.—The board of directors shall select the organization or organizations to function as the National Information Sharing Organization by taking into consideration the following criteria and other criteria found appropriate by the board:

''(1) Whether the organization or organizations have received recognition from the Secretary of Homeland Security for its cyber capabilities.

''(2) Whether the organization or organizations have demonstrated the ability to address cyber-related issues in a trusted and cooperative environment maximizing public-private partnerships.

''(3) Whether the organization or organizations have demonstrated the capability to deploy cybersecurity services for the detection, prevention, and mitigation of cyber-related issues.

''(4) Whether the organization or organizations have an operational center that is open 24 hours a day, seven days a week, and is capable of determining, analyzing, and responding to cyber events.

''(5) Whether the organization or organizations have a proven relationship with the private sector critical infrastructure sectors.

''(6) Whether the organization or organizations have experience implementing privacy protections to safeguard, sensitive information, including personally identifiable information, in transit and at rest.

**''SEC. 242. MISSION AND ACTIVITIES.**

''The National Information Sharing Organization shall—

''(1) facilitate the exchange of information, best practices, technical assistance, and support related to the security of public, private, and critical infrastructure information networks, including by—

''(A) ensuring that the information exchanged shall be stripped of all information identifying the submitter and of any unnecessary personally identifiable information and shall be available to members of the National Information Sharing Organization, including Federal, State, and local government agencies; and

''(B) sharing timely and actionable threat and vulnerability information originating through intelligence collection with appro-

priately cleared members of the National Information Sharing Organization;

''(2) create a common operating picture by combining agreed upon network and cyber threat warning information to be shared—

''(A) through a secure automated mechanism to be determined by the board; and

''(B) with designated members of the National Information Sharing Organization, including the Federal Government;

''(3) undertake collaborative research and development projects to improve the level of cybersecurity in critical infrastructure information systems while maintaining impartiality, the independence of members of the National Information Sharing Organization, and vendor neutrality;

''(4) develop language to be incorporated into the membership agreement regarding the transferability and use of intellectual property developed by the National Information Sharing Organization and its members under this subtitle; and

''(5) integrate with the Federal Government through the National Cybersecurity and Communications Integration Center and other existing information sharing and analysis centers, as appropriate.

**''SEC. 243. BOARD OF DIRECTORS.**

''(a) IN GENERAL.—The National Information Sharing Organization shall have a board of directors which shall be responsible for—

''(1) the executive and administrative operation of the National Information Sharing Organization, including matters relating to funding and promotion of the National Information Sharing Organization; and

''(2) ensuring and facilitating compliance by members of the National Information Sharing Organization with the requirements of this subtitle.

''(b) COMPOSITION.—The board shall be composed of the following members:

''(1) One representative from the Department of Homeland Security.

''(2) Four representatives from three different Federal agencies with significant responsibility for cybersecurity.

''(3) Ten representatives from the private sector, including at least one member representing a small business interest and members representing each of the following critical infrastructure sectors and subsectors:

''(A) Banking and finance.

''(B) Communications.

''(C) Defense industrial base.

''(D) Energy, electricity subsector.

''(E) Energy, oil, and natural gas subsector.

''(F) Heath care and public health.

''(G) Information technology.

''(4) Two representatives from the privacy and civil liberties community.

''(5) The Chair of the National Council of Information Sharing and Analysis Centers.

''(c) INITIAL APPOINTMENT.—Not later than 30 days after the date of the enactment of this subtitle, the Secretary of Homeland Security, in consultation with the heads of the sector specific agencies of the sectors and subsectors referred to in subsection (b)(3), shall appoint the members of the board described under subsection (b)(3) from individuals identified by the sector coordinating councils of sectors and subsectors referred to in subsection (b)(3).

''(d) TERMS.—

''(1) REPRESENTATIVES OF CERTAIN FEDERAL AGENCIES.—Each member of the board described in subsection (b)(1) and (b)(2) shall be appointed for a term that is not less than one year and not longer

than three years from the date of the member's appointment.

''(2) OTHER REPRESENTATIVES.—The original private sector members of the board described subsection (b) shall serve an initial term of one year from the date of appointment under subsection (c), at which time the members of the National Information Sharing Organization shall conduct elections in accordance with the procedures established under subsection (e).

''(e) RULES AND PROCEDURES.—Not later than 90 days after the date of the enactment of this Act, the board shall establish rules and procedures for the election and service of members of the board described in paragraphs (3) and (4) of subsection (b).

''(f) LEADERSHIP.—The board shall elect from among its members a chair and vice-chair of the board, who shall serve under such terms and conditions as the board may establish. The chair of the board may not be a Federal employee.

''(g) SUB-BOARDS.—The board shall have the authority to constitute such sub-boards, or other advisory groups or panels, as may be necessary to assist the board in carrying out its functions under this section. The board shall establish an advisory group made up of the members

determined appropriate to participate in the common operation picture described in section 242(2) and to determine information sets, sharing procedures, and operational protocols in creating the common operating picture.

**''SEC. 244. CHARTER.**

''The board shall develop a charter to govern the operations and administration of the National Information Sharing Organization. The charter shall cover each of the following:

''(1) The organizational structure of the National Information Sharing Organization.

''(2) The governance of the National Information Sharing Organization.

''(3) A mission statement of the National Information Sharing Organization.

''(4) Criteria for membership of the National Information Sharing Organization and for termination of such membership.

''(5) A funding model of the National Information Sharing Organization, including costs, if any, for membership.

''(6) Rules for sharing information with members of the National Information Sharing Organization, including the treatment and ownership of intellectual property provided by or to the National In-

formation Sharing Organization, limitations on liability, and consideration of any necessary measures to mitigate anti-trust concerns.

''(7) Technical requirements for participation in the common operating picture and a technical architecture that enables an automated, real-time sharing among members and Federal Government agencies.

''(8) Rules for participating in collaborative research and development projects.

''(9) Protections of privacy and civil liberties to be used by the National Information Sharing Organization and its members, including appropriate measures for public transparency and oversight.

''(10) Security requirements and member obligations for the protection of information from other sources, including private and governmental.

''(11) Procedures for making anonymized cyber incident information available to outside groups for academic research and insurance actuarial purposes.

**''SEC. 245. MEMBERSHIP.**

''Not later than 90 days after the date of the enactment of this subtitle, the board of directors of the National Information Sharing Organization shall establish criteria procedures for the voluntary membership by State and local government departments, agencies, and entities, pri-

vate sector businesses and organizations, and academic institutions in the National Information Sharing Organization.

**''SEC. 246. FUNDING.**

''Annual administrative and operational expenses for the National Information Sharing Organization shall be paid by the members of such Organization, as determined by the board of directors of the Organization.

**''SEC. 247. CLASSIFIED INFORMATION.**

''Consistent with the protection of sensitive intelligence sources and methods, the Secretary, in conjunction with the Director of National Intelligence, shall facilitate—

''(1) the sharing of classified information in the possession of a Federal agency related to threats to information networks with cleared members of the National Information Sharing Organization, including representatives of the private sector and of public and private sector entities operating critical infrastructure; and

''(2) the declassification and sharing of information in the possession of a Federal agency related to threats to information networks with members of the National Information Sharing Organization.

**''SEC. 248. VOLUNTARY INFORMATION SHARING.**

''(a) IN GENERAL.—

''(1) CYBERSECURITY PROVIDERS.—Notwithstanding any other provision of law, a cybersecurity provider may, with the express consent of a protected entity for which such cybersecurity provider is providing goods or services for cybersecurity purposes, use cybersecurity systems to identify and obtain cyber threat information to protect the rights and property of such protected entity.

''(2) PROTECTED ENTITIES.—Notwithstanding any other provision of law, a protected entity may, for cybersecurity purposes—

''(A) share cyber threat information with the National Information Sharing Organization and its membership, including the Federal Government; or

''(B) authorize their cybersecurity provider to share on their behalf with the National Information Sharing Organization and its membership, including the Federal Government.

''(3) SELF-PROTECTED ENTITIES.—Notwithstanding any other provision of law, a self-protected entity may, for cybersecurity purposes—

''(A) use cybersecurity systems to identify and obtain cyber threat information to protect

the rights and property of such self-protected entity; and

''(B) share such cyber threat information with the National Information Sharing Organization and its membership, including the Federal Government.

''(b) USES OF SHARED INFORMATION.—Notwithstanding any other provision of law, information shared with or provided to the National Information Sharing Organization or to a Federal agency or private entity through the National Information Sharing Organization by any member of the National Information Sharing Organization that is not a Federal agency in furtherance of the mission and activities of the National Information Sharing Organization as described in section 242—

''(1) shall be exempt from disclosure under section 552 of title 5, United States Code (commonly referred to as the Freedom of Information Act);

''(2) shall not, without the written consent of the person or entity submitting such information, be used directly by any Federal agency, any other Federal, State, tribal, or local authority, or any third party, in any civil action arising under Federal or State law if such information is submitted to the National Information Sharing Organization for the

purpose of facilitating the missions of such Organization, as articulated in the mission statement required under section 244;

''(3) shall not, without the written consent of the person or entity submitting such information, be used or disclosed by any officer or employee of the United States for purposes other than the purposes of this title, including any regulatory purpose, except—

''(A) to further an investigation or the prosecution of a cybersecurity related criminal act; or

''(B) to disclose the information to the appropriate congressional committee;

''(4) shall not, if subsequently provided to a State or local government or government agency—

''(A) be made available pursuant to any State or local law requiring disclosure of information or records;

''(B) otherwise be disclosed or distributed to any party by such State or local government or government agency without the written consent of the person or entity submitting such information; or

''(C) be used other than for the purpose of protecting information systems, or in furtherance of an investigation or the prosecution of a criminal act;

''(5) does not constitute a waiver of any applicable privilege or protection provided under law, such as information that is proprietary, business sensitive, relates specifically to the submitting person or entity, or is otherwise not appropriately in the public domain; and

''(6) shall not be the basis for any civil or criminal right of action in Federal or State court for a failure to warn or disclose provided that the information is shared with the Federal Government through the National Information Sharing Organization in accordance with the procedures established under this section.

''(c) LIMITATION.—The Federal Advisory Committee Act (5 U.S.C. App.) shall not apply to any communication of information to a Federal agency made pursuant to this title.

''(d) PROCEDURES.—

''(1) IN GENERAL.—Not later than 90 days after the date of the enactment of this subtitle, the board of directors of the National Information Shar-

ing Organization shall establish uniform procedures for the receipt, care, and storage of information that is voluntarily submitted to the Federal Government through the National Information Sharing Organization.

''(2) ELEMENTS.—The procedures established under paragraph (1) shall include procedures for—

''(A) the acknowledgment of receipt by the National Information Sharing Organization of cyber threat information that is voluntarily submitted to the National Information Sharing Organization;

''(B) the maintenance of the identification of such information;

''(C) the care and storage of such information;

''(D) limiting subsequent dissemination of such information to ensure that such information is not used for an unauthorized purpose;

''(E) the protection of the privacy rights and civil liberties of any individuals who are subjects of such information; and

''(F) the protection and maintenance of the confidentiality of such information so as to permit the sharing of such information within

the Federal Government and with State, tribal, and local governments, and the issuance of notices and warnings related to the protection of information networks, in such manner as to protect from public disclosure the identity of the submitting person or entity, or information that is proprietary, business sensitive, relates specifically to the submitting person or entity, and is otherwise not appropriately in the public domain.

''(e) INDEPENDENTLY OBTAINED INFORMATION.—Nothing in this section shall be construed to limit or otherwise affect the ability of a Federal agency, a State, tribal, or local government or government agency, or any third party—

''(1) to obtain or disseminate cyber threat information in a manner other than through the National Information Sharing Organization; and

''(2) to use such information in any manner permitted by law.

''(f) DEFINITIONS.—In this section:

''(1) The term 'cybersecurity provider' means a non-governmental entity that provides goods or services intended to be used for cybersecurity purposes.

''(2) The term 'cybersecurity purpose' means the purpose of ensuring the integrity, confidentiality, or availability of, or safeguarding, a system or network, including protecting a system or network from—

''(A) efforts to degrade, disrupt or destroy such system or network; or

''(B) theft or misappropriation of private or government information, intellectual property, or personally identifiable information.

''(3) The term 'cybersecurity system' means a system designed or employed to ensure the integrity, confidentiality, or availability of, or safeguarding, a system or network, including protecting a system or network from—

''(A) efforts to degrade, disrupt or destroy such system or network; or

''(B) theft or misappropriation of private or government information, intellectual property, or personally identifiable information.

''(4) The term 'cyber threat information' means information that is—

''(A) necessary to describe a method of defeating technical controls on a system or network that corresponds to a cyber threat; and

''(B) omits all other information not necessary to describe such threat.

''(5) The term 'protected entity' means an entity, other than an individual, that contracts with a cybersecurity provider for goods or services to be used for cybersecurity purposes.

''(6) The term 'self-protected entity' means an entity, other than an individual, that provides goods or services for cybersecurity purposes to itself.

**''SEC. 249. ANNUAL INDEPENDENT AUDITS.**

''The board of directors of the National Information Sharing Organization shall commission, on an annual basis, an audit by a qualified, independent auditing firm approved by the Secretary, to review the compliance of the National Information Sharing Organization and its members with the information sharing rules set forth in section 248 and the information sharing rules established by the board pursuant to the National Information Sharing Organization charter required under section 244. Such audit—

''(1) shall identify instances in which information may have been shared in a manner inconsistent with procedures required under section 248 or with the information sharing rules established by the board pursuant to section 244, with the National In-

formation Sharing Organization, with members of the National Information Sharing Organization, or by the National Information Sharing Organization with a National Information Sharing Organization member or other entity or individual;

''(2) shall be provided to the Secretary and to the Committee on Homeland Security of the House of Representatives and to the Homeland Security and Governmental Affairs Committee of the Senate;

''(3) shall be made public, with appropriate redactions to protect the identity of National Information Sharing Organization members; and

''(4) may include a classified annex.

**''SEC. 250. PENALTIES.**

''(a) IN GENERAL.—It shall be unlawful for any officer, employee, representative, or agent of the United States or of any Federal agency, or any employee or officer of the National Information Sharing Organization, its member entities, and any representatives or agents of the National Information Sharing Organization or its member entities to knowingly publish, divulge, disclose, or make known in any manner or to any extent not authorized by law, any cyber threat information protected from disclosure by this title coming to such officer or employee in the course of the employee's employment or official duties

or by reason of any examination or investigation made by, or return, report, or record made to or filed with, such officer, employee, or agency.

''(b) PENALTY.—Any person who violates subsection (a) shall be fined under title 18, United States Code, imprisoned for not more than one year, or both, and shall be removed from office or employment.

**''SEC. 251. AUTHORITY TO ISSUE WARNINGS.**

''The Secretary may provide advisories, alerts, and warnings to relevant companies, targeted sectors, other government entities, or the general public regarding potential threats to information networks as appropriate. In issuing such an advisory, alert, or warning, the Secretary shall take appropriate actions to protect from disclosure—

''(1) the source of any voluntarily submitted information that forms the basis for the advisory, alert, or warning; and

''(2) information that is proprietary, business sensitive, relates specifically to the submitting person or entity, or is otherwise not appropriate for disclosure in the public domain.

**''SEC. 252. EXEMPTION FROM ANTITRUST PROHIBITIONS.**

''The exchange of information by and between private sector members of the National Information Sharing Organization in furtherance of the mission and activities of

the National Information Sharing Organization shall not be considered a violation of any provision of the antitrust laws (as such term is defined in the first section of the Clayton Act (15 U.S.C. 12)).

**''SEC. 253. LIMITATION.**

''For any fiscal year after fiscal year 2015, the amount authorized to be appropriated for the National Information Sharing Organization may not exceed the amount provided by the largest private sector member of the National Information Sharing Organization for that fiscal year.''.

(2) CLERICAL AMENDMENT.—The table of contents in section 2(b) of such Act, as amended by section 2, is further amended by adding at the end of the items relating to title II the following new items:

''Subtitle E—National Information Sharing Organization

''Sec. 241. Establishment of National Information Sharing Organization.
''Sec. 242. Mission and activities.
''Sec. 243. Board of directors.
''Sec. 244. Charter.
''Sec. 245. Membership.
''Sec. 246. Funding.
''Sec. 247. Classified information.
''Sec. 248. Voluntary information sharing.
''Sec. 249. Annual independent audits.
''Sec. 250. Penalties.
''Sec. 251. Authority to issue warnings.
''Sec. 252. Exemption from antitrust prohibitions.
''Sec. 253. Limitation.''.

(b) INITIAL EXPENSES.—There is authorized to be appropriated $10,000,000 for each of fiscal years 2013, 2014, and 2015 for initial expenses associated with the

establishment of the National Information Sharing Organization under subtitle E of title II of the Homeland Security Act of 2002, as added by subsection (a). Such amounts shall be derived from amounts appropriated for the operations of the Management Office for the Directorate of Science and Technology of the Department of Homeland Security.

Æ

**From:** Guy V. Zito
**Sent:** Wednesday, May 09, 2012 2:35 PM
**To:** rsc
**Subject:** HR 3674 Cyber Security Legislation
**Attachments:** BILLS-112hr3674ih.pdf

RSC,

Please note the attached is in the House of Representative of the US Govt. It basically provides the government with added authority to address cyber threats to our critical infrastructure. I have been following this and have concerns that the existing NIST standards that are out there and that the govenment abides by may be made law at some point, especially if the CIP Version 5 fails. Please consider this when as we develop recommended ballot positions for the CIP 5 Standards. I attached it for your convenience. I am unsure when this will be voted on in the "House". See Page 6 Paragraphs 6 and 11. This would effectively give the Secretary of Homeland Security to make compliance to the NIST standards mandatory and enforceable outside of the FPA 215 and create a new law, in my read of it.

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:** Kimberly Mielcarek
**To:** Kimberly Mielcarek
**Subject:** NERC Announcement - New Technical Standard for Synchrophasors Adopted by the International Electrotechnical Commission
**Date:** Friday, May 18, 2012 11:27:09 AM

# Announcement

## New Technical Standard for Synchrophasors Adopted by the International Electrotechnical Commission

**Click here for announcement**

**ATLANTA** – The North American Electric Reliability Corporation (NERC) and the North American SynchroPhasor Initiative (NASPI) is pleased with the International Electrotechnical Commission's (IEC's) adoption of a technical standard that establishes improved synchrophasor data communication. The approval of technical interoperability standards is an important milestone marking the maturity synchrophasor technology and systems. Further, industry consensus allows manufacturers to standardize their offerings.

For more information or assistance, please contact Kimberly Mielcarek.

**3353 Peachtree Road NE**
**Suite 600, North Tower**
**Atlanta, GA 30326**
**404-446-2560 | www.nerc.com**

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION









# Announcement

## New Technical Standard for Synchrophasors Adopted by the International Electrotechnical Commission

May 18, 2012

**ATLANTA** – The North American Electric Reliability Corporation (NERC) and the North American SynchroPhasor Initiative (NASPI) is pleased with the International Electrotechnical Commission's (IEC's) adoption of a technical standard that establishes improved synchrophasor data communication. The approval of technical interoperability standards is an important milestone marking the maturity synchrophasor technology and systems. Further, industry consensus allows manufacturers to standardize their offerings.

"Adoption of this IEC standard supports the integration of synchrophasor technology into day-to-day grid operations," said Mark Lauby, vice president and director of Reliability Assessment and Performance Analysis at NERC. "We appreciate the hard work of volunteer experts from IEC, the Institute of Electrical and Electronics Engineers (IEEE), NASPI and the federal government who contributed to the development of this technical standard."

IEC 61850-90-5 is one of several key technical interoperability standards adopted to advance smart grid technology. The new standard addresses delivery of high-speed data collected by synchronized phasor measurement devices over wide-area communications networks. Further, they incorporate data latency requirements for Wide-Area Monitoring Protection and Control applications and assure cybersecurity protection for this data.

The Department of Energy is working with the National Institute of Standards and Technology (NIST) to accelerate the development of key smart grid interoperability standards, including IEC 61850-90-5, with funding and coordination. NASPI's Performance and Standards Task Team (PSTT), working with NIST, continues to develop standards and guidelines for phasor measurement units, phasor data concentrators, GPS time-stamping of phasor data, and related synchrophasor technology elements.

**CONTACT:**
**Kimberly.Mielcarek@nerc.net**

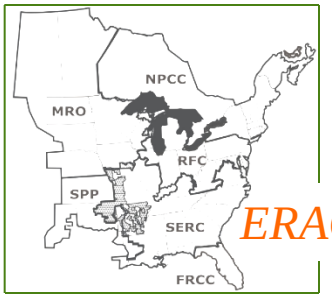
**3353 Peachtree Road NE**
**Suite 600, North Tower**
**Atlanta, GA 30326**
**404-446-2560 | www.nerc.com**

More than 65 transmission owners and operators across North America have deployed synchrophasor systems to monitor transmission grid conditions and improve grid operations. Most of these phasor projects have received financial and technical support from the Department of Energy under the Smart Grid Investment Grants funded by the 2009 American Reinvestment and Recovery Act.

The North American SynchroPhasor Initiative (NASPI) is an international collaborative effort between NERC, the Department of Energy and the North American electric industry focused on accelerating the use of synchrophasor technology to enhance grid reliability. For more information, visit NASPI website.

###

*The North American Electric Reliability Corporation's mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission in the United States to establish and enforce reliability standards for the bulk-power system. NERC has equivalent relationships with provincial and federal authorities in Canada. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast, and summer and winter forecasts; monitors the bulk power system; and educates, trains and certifies industry personnel. Learn more at www.nerc.com*

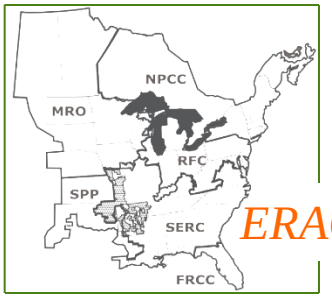


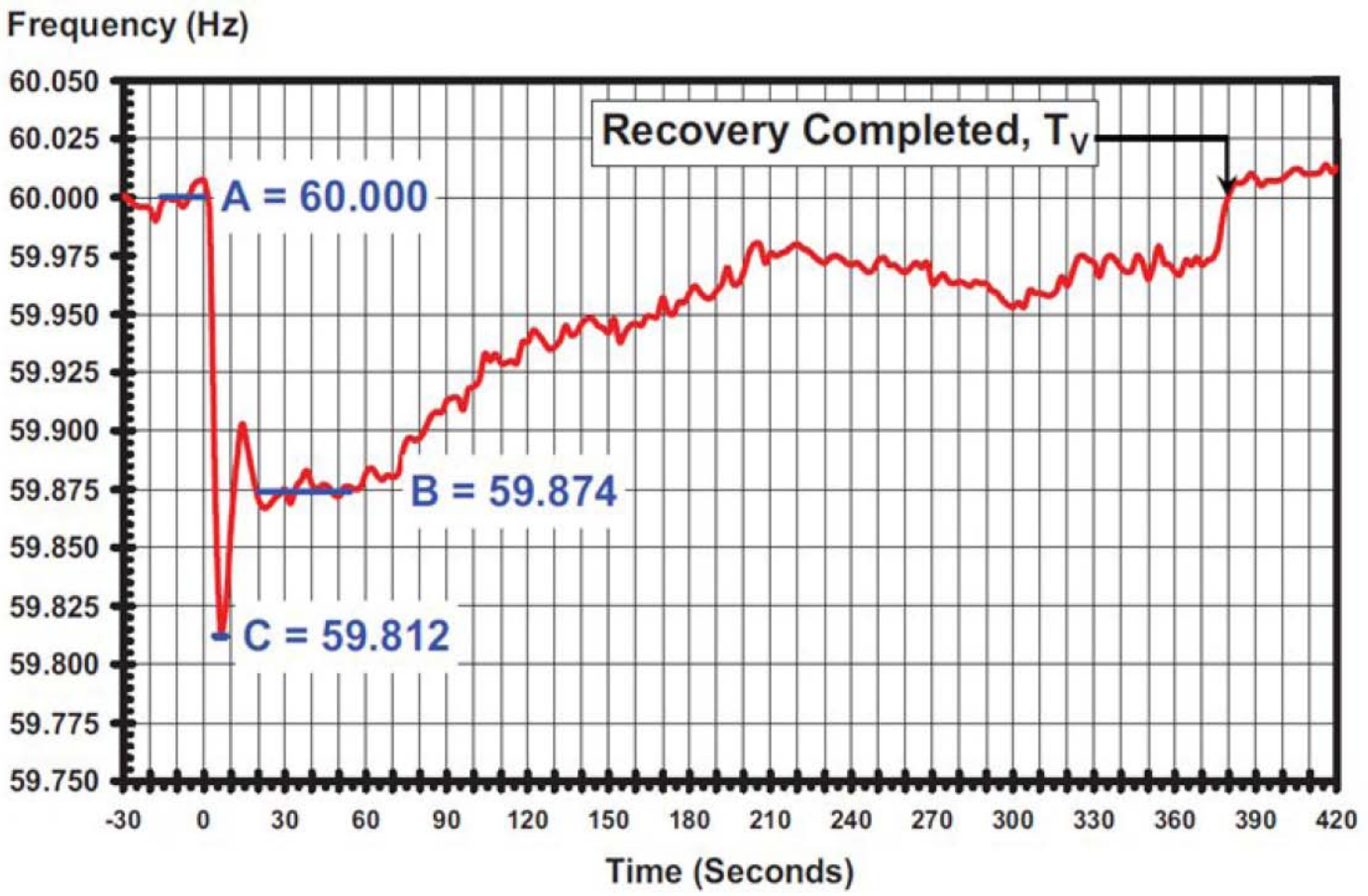

# Eastern Interconnection System Modeling – Frequency Response Modeling

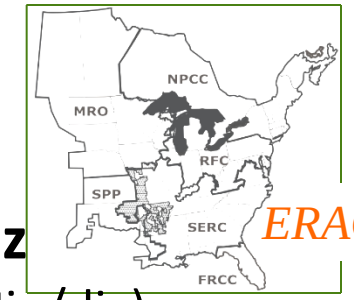
NERC Modeling Workshop, May 2-3, 2012

Paul Roman-Manager, Operations Planning
Northeast Power Coordinating Council-ERAG Management Committee

# Desired System Frequency Recovery

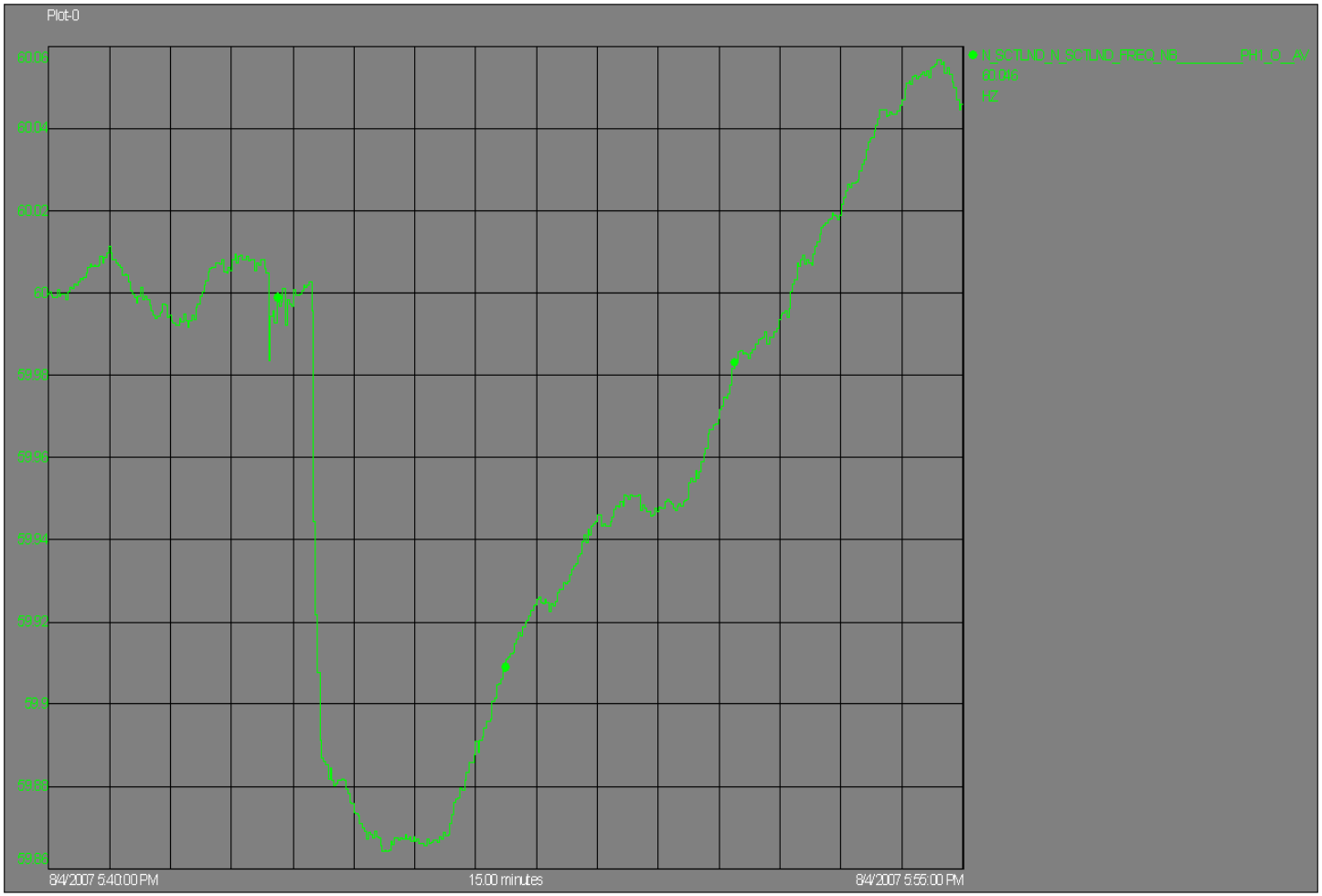


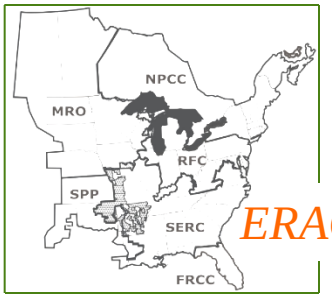






# AUGUST 04, 2007 frequency decline 0.117Hz

Freq. 59.86-60.06 Hz (.02Hz/div), Time 0 to 15 Minutes (1Min/div)

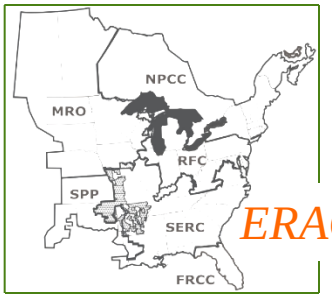





# Frequency Response and Control

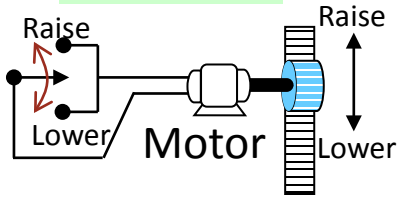
- Inertial Response (Rotating mass of generators and load determine point C)
- Primary Response-Governors-Point B
  - (Unit load controller action can significantly affect governor response)
- Secondary Response-Automatic Generation Control
- Operating Reserves

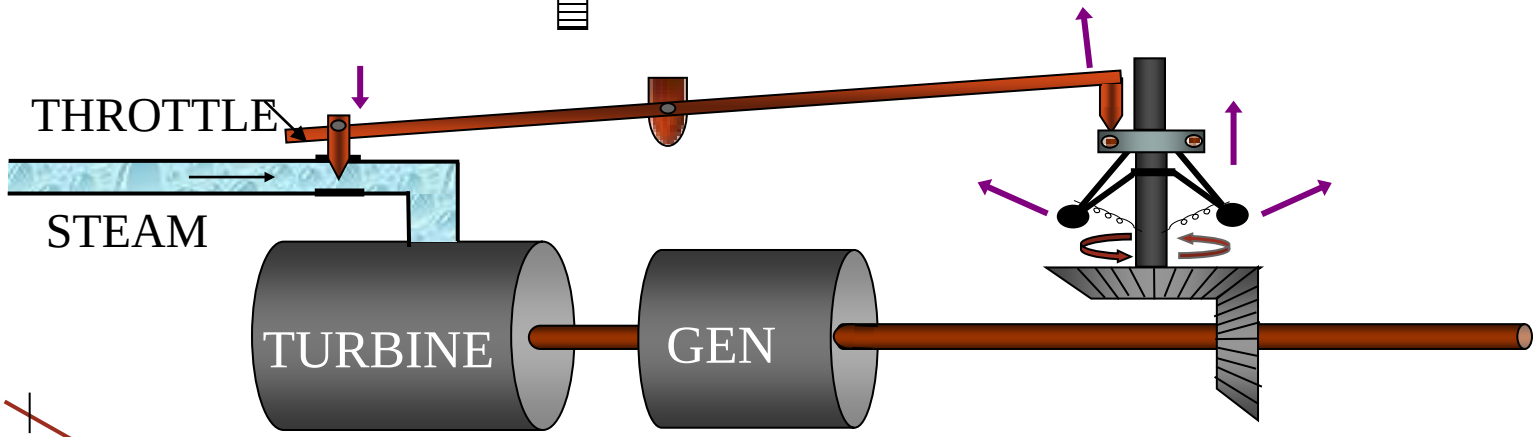
# Response from Governors

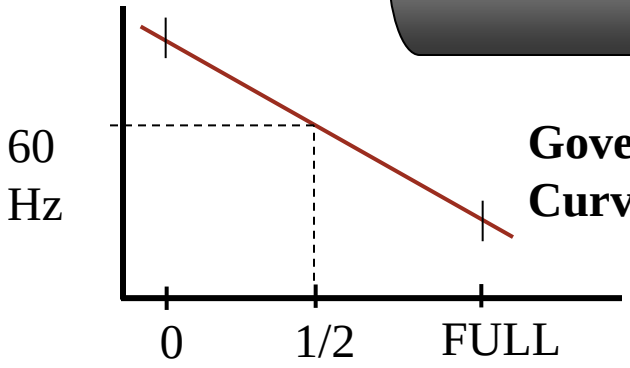



**Speed / Load Control**

**THE GOVERNOR**



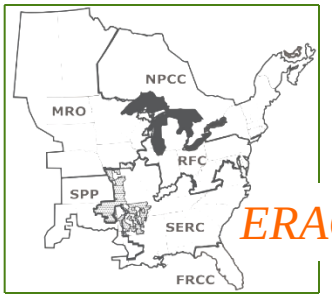




**Governor "Droop" Curve**

$$\text{Slope} = \frac{\Delta \text{Freq}}{\Delta \text{Load}}$$

5% droop = 0.05 Hz/MW




# Governor Droop

-Δ freq/Droop (Hz) = Δ MW/rated MW

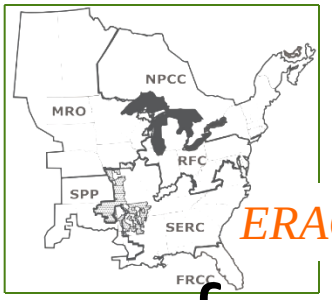
For a 1,000 MW generator, 5% droop and Δ freq of 0.1 Hz

<u>To calculate expected MW output change:</u>

Convert the droop (e.g. 5%) to Freq. .05 x 60 = 3 Hz

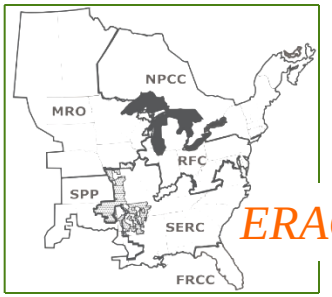
-0.1 Hz/3 Hz = ΔMW/1,000 MW

1,000 x .1 / 3 = 33 MW

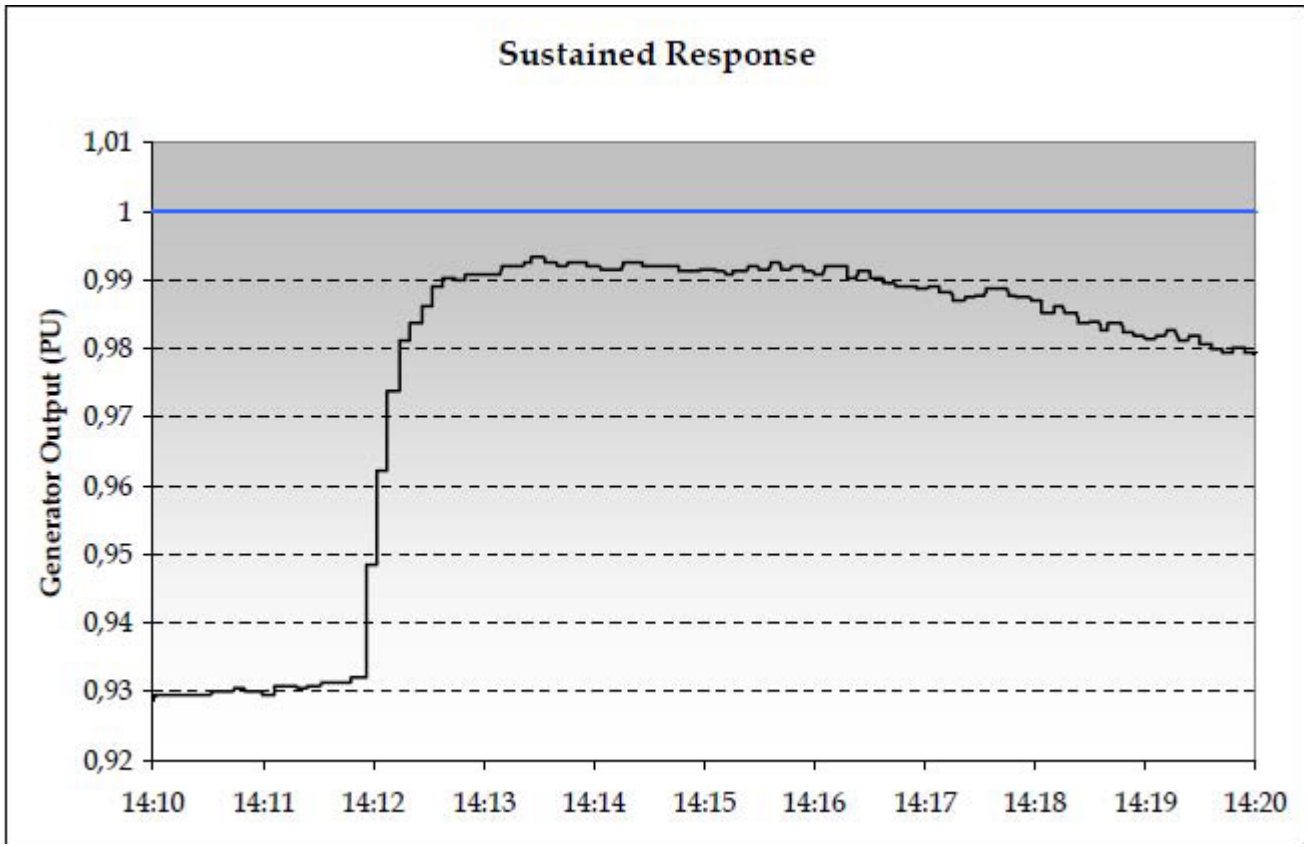


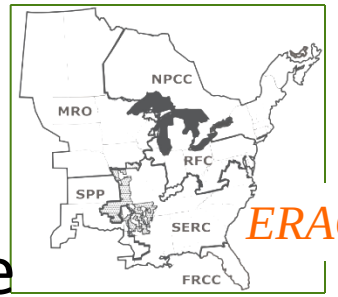

# Frequency Response Examples-by Type of Generator

- Examples are meant to provide approximation of the trends of responses for different generators
- Many responses of generators have been monitored, Similar to what is seen from reviewing many actual unit responses
- Governor response varies by: 1) type of generator and 2) generator to generator
- Examples based on two different large capacity loss events (8/4/2007, 4/27/2011)



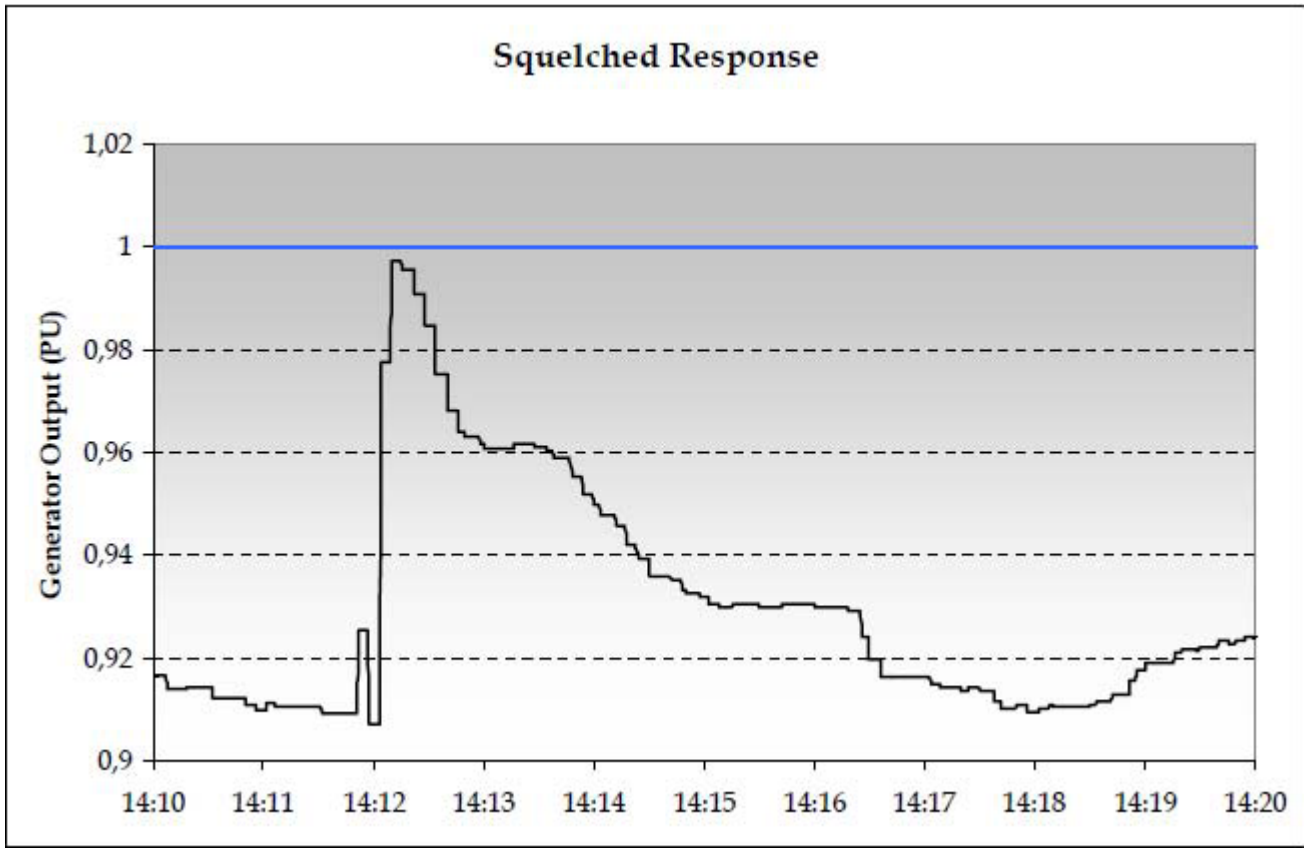

# Sustained Governor Response Example

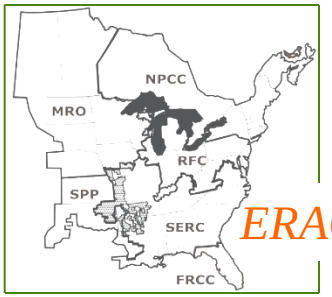




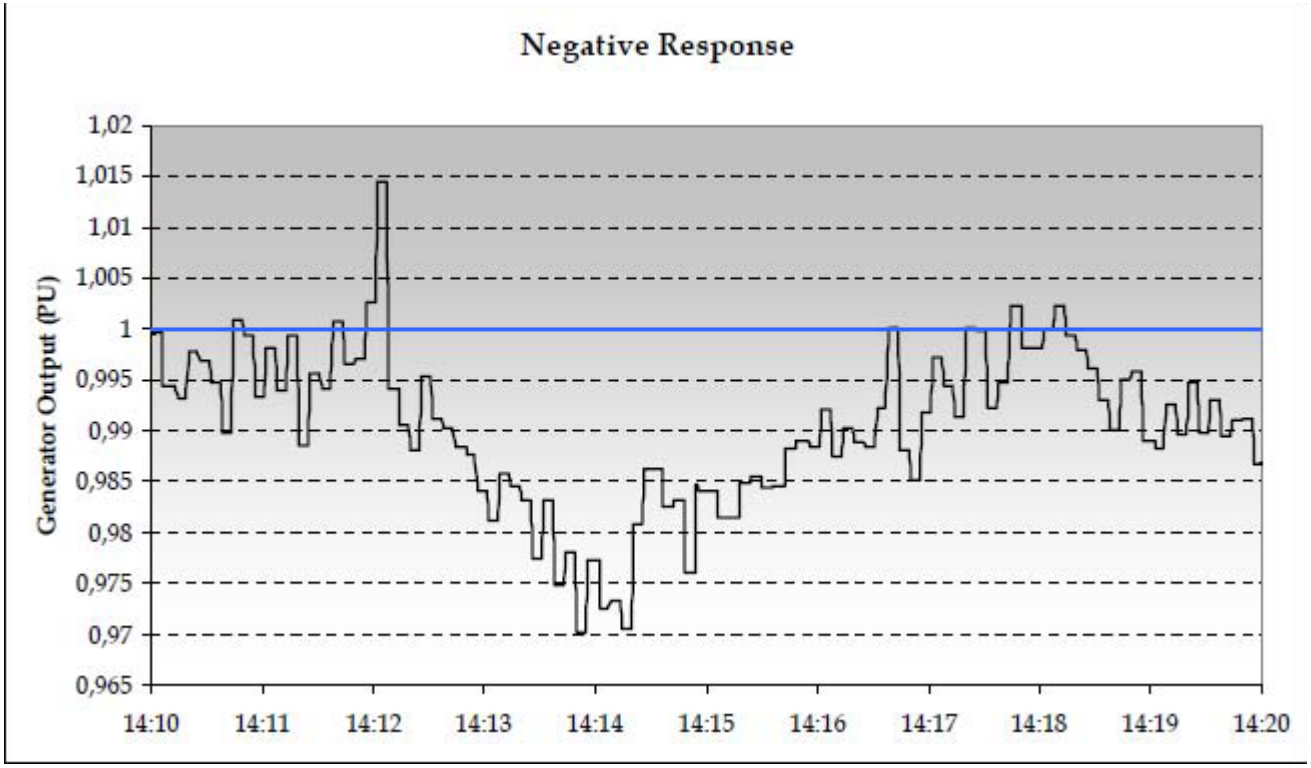

ERAG

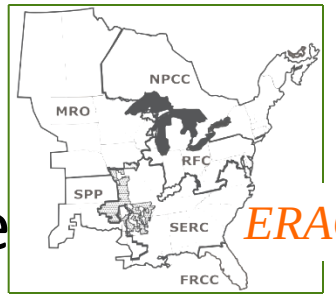
# Squelched Governor Response Example



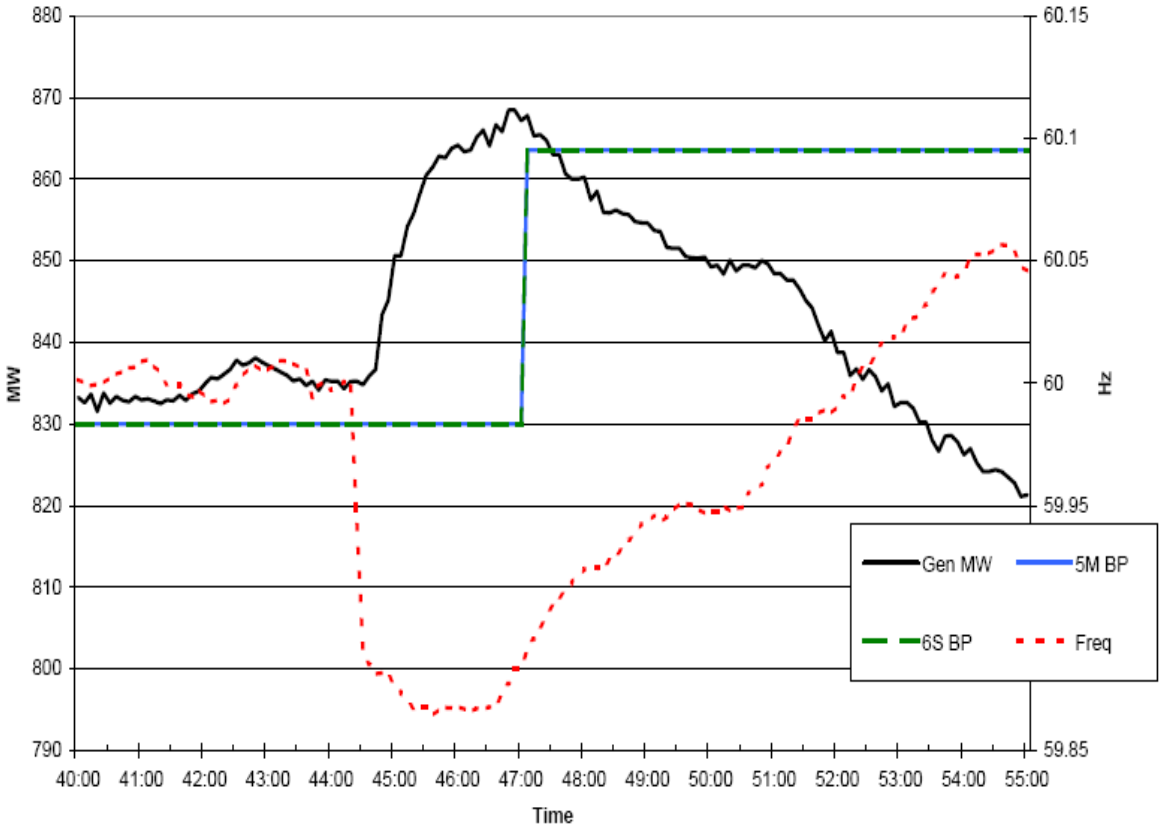



# Negative Governor Response Example

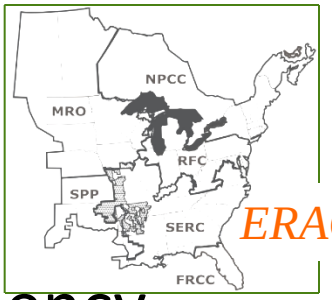





# Example Hydro Generating Plant Response AUGUST 04, 2007 frequency decline

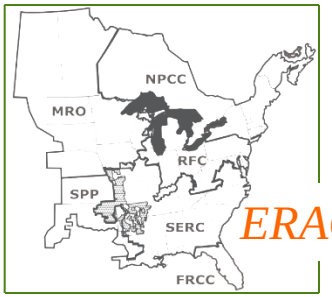



900 MW, based on 5% droop Expect 33 MW

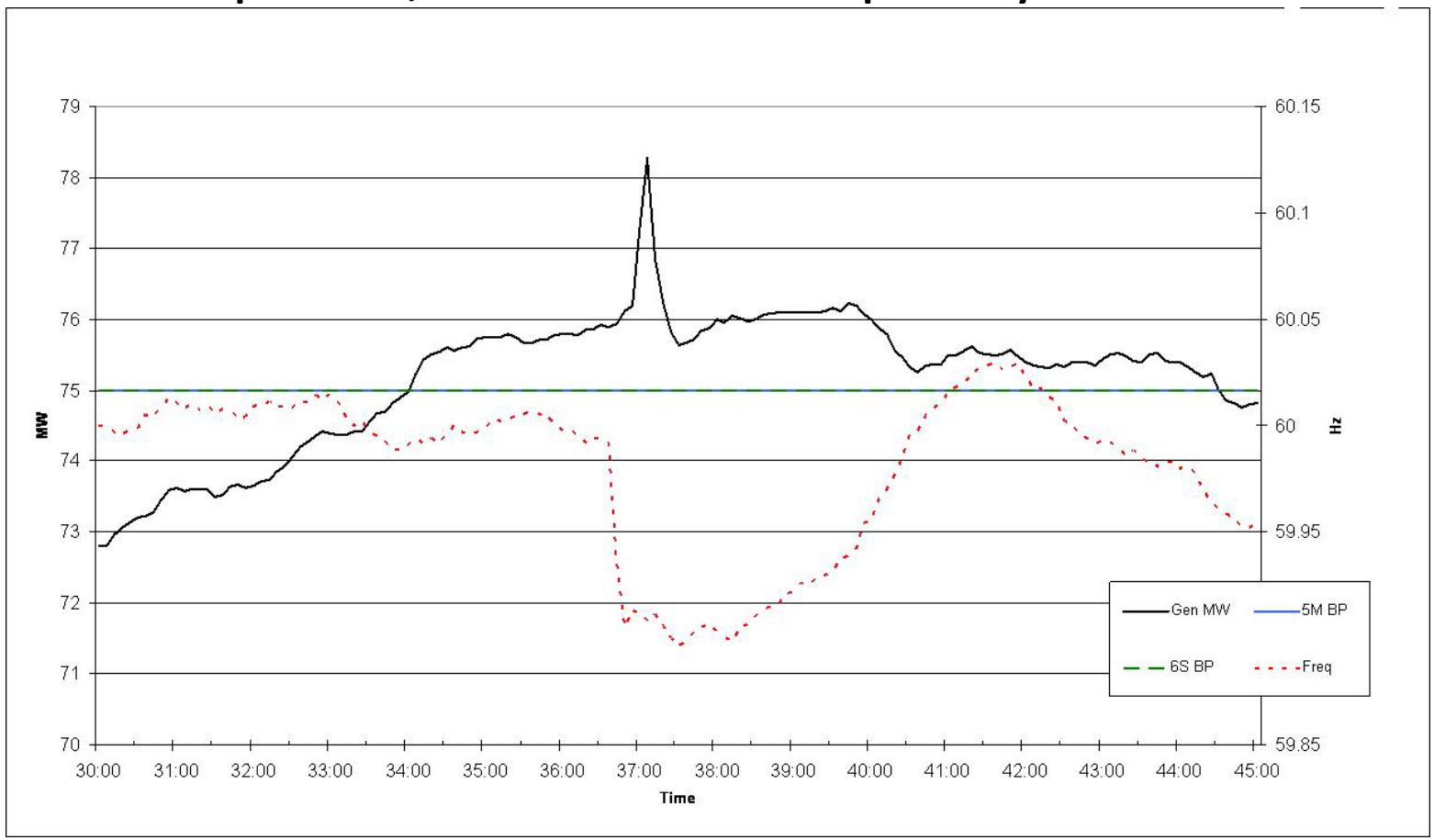



# System Frequency Event and Example Frequency Responses from Various Generators (April 27, 2011)



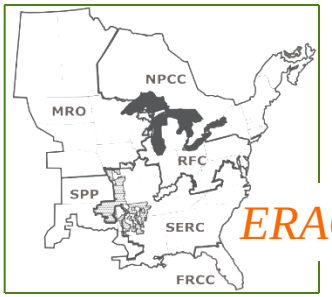



# EX "A" Small Thermal Unit Response
# April 27, 2011 HB17 frequency decline

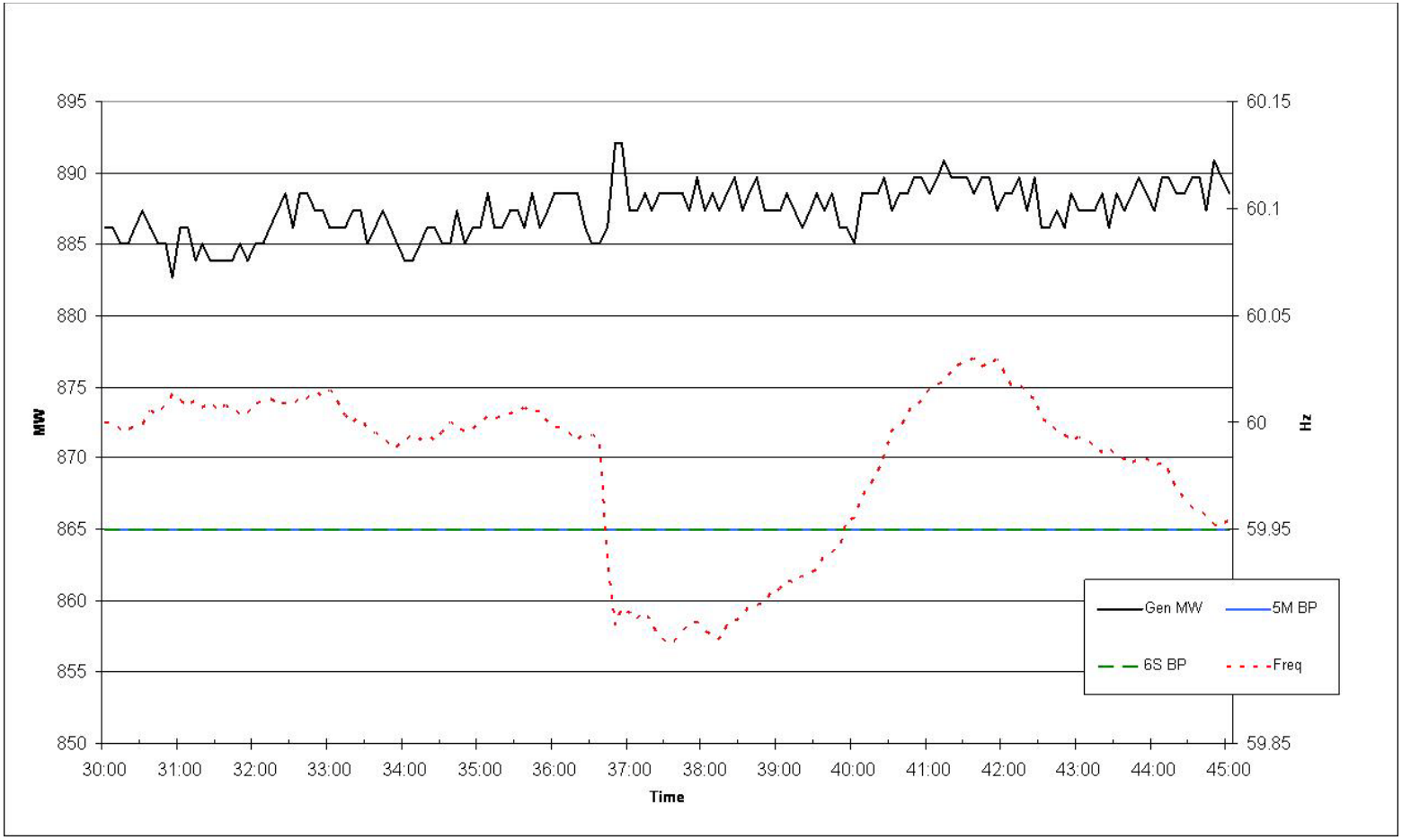




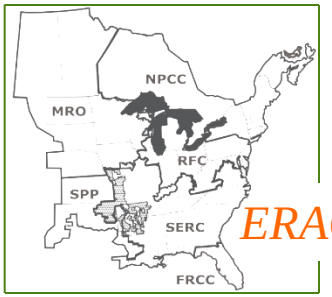

90 MW, Expect 3 MW



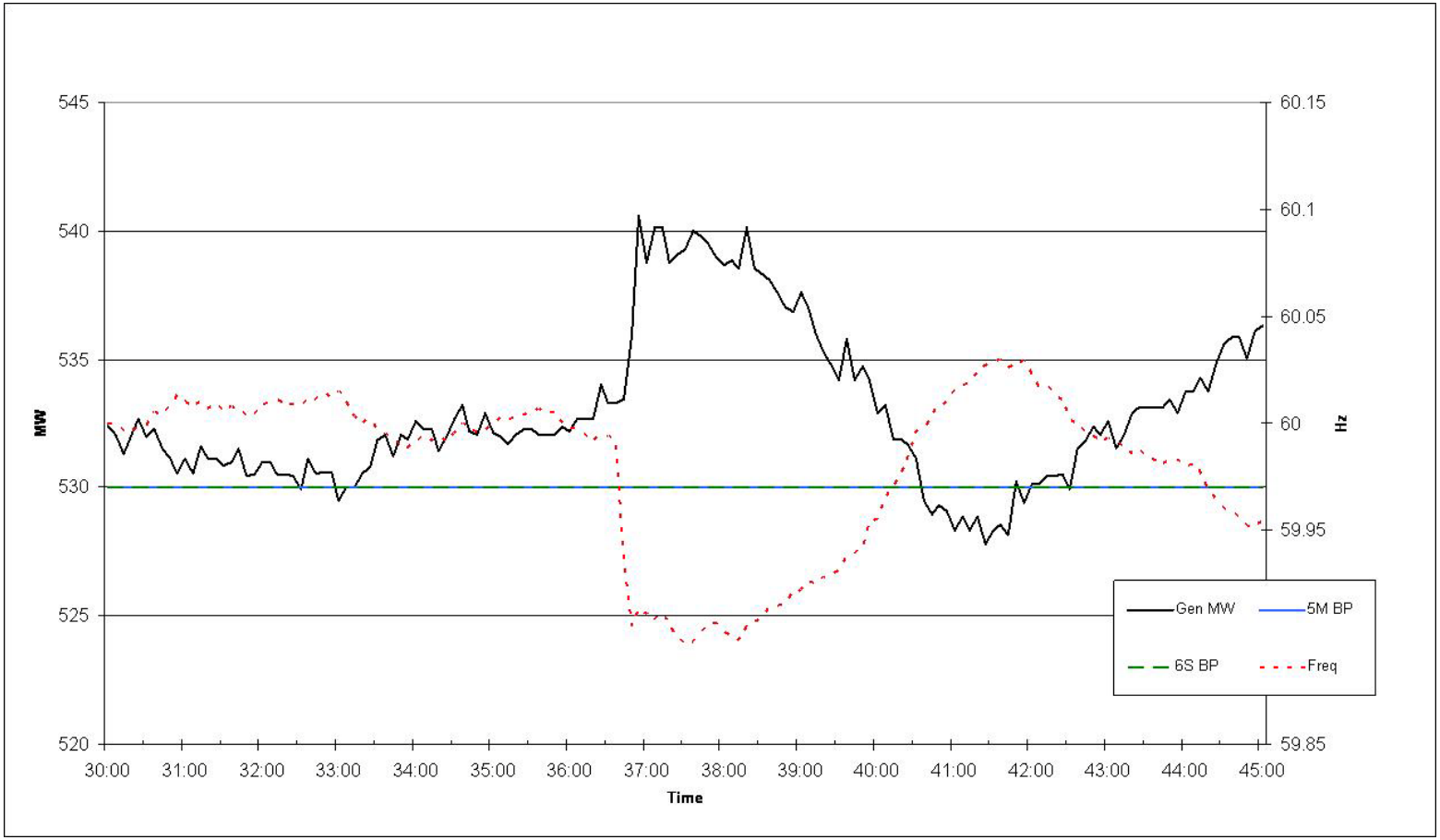

# EX “B” Large Thermal Unit Response
# April 27, 2011 HB17 frequency decline



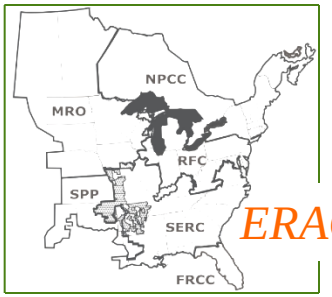

900 MW, expect 35 MW, response 7 MW



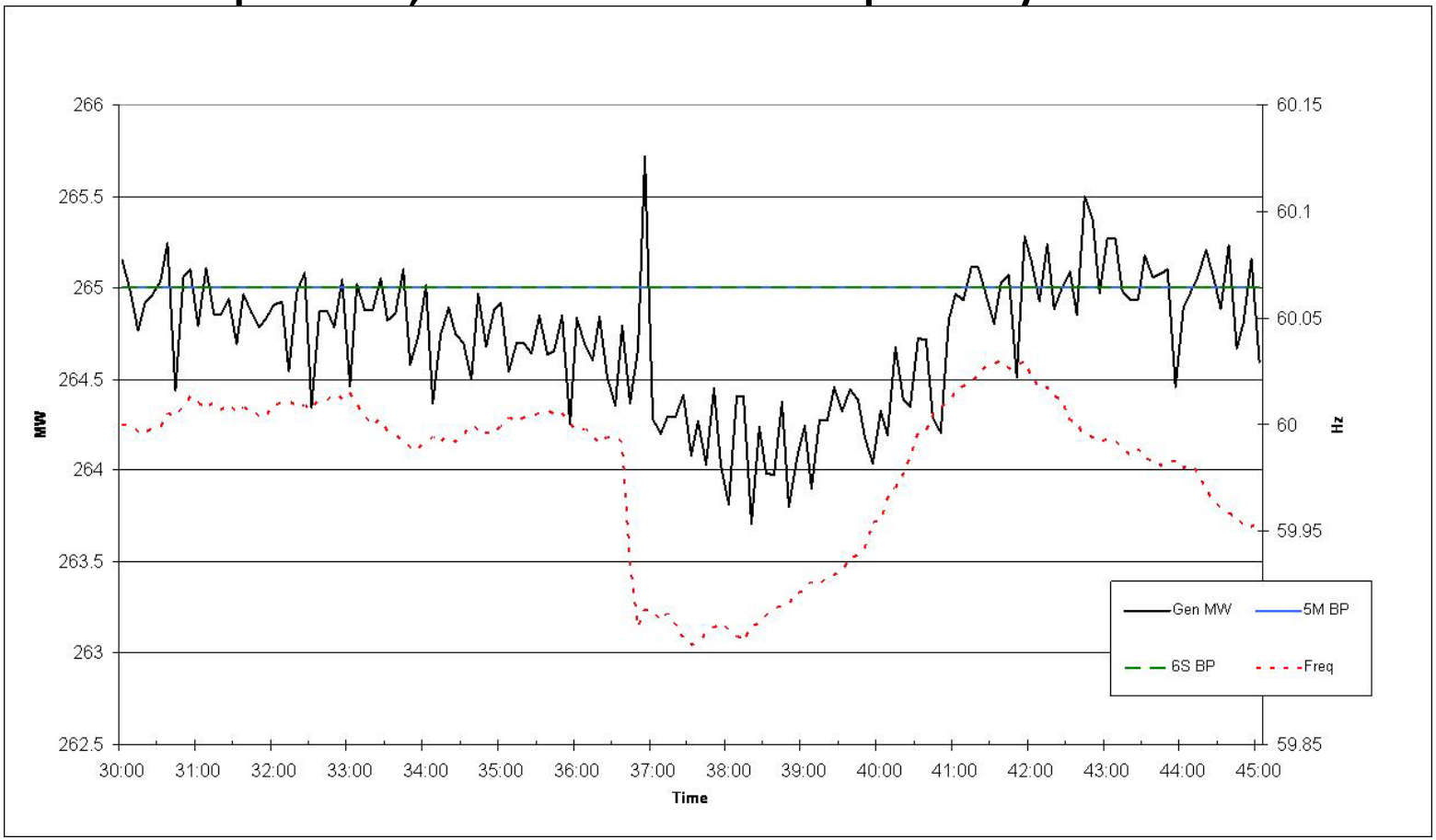

# EX A Combined Cycle Unit Response
# April 27, 2011 HB17 frequency decline



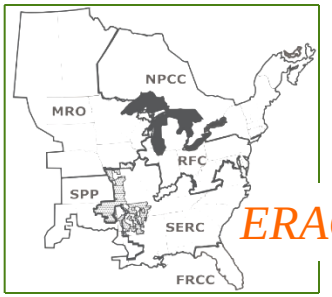

550 MW, expect 21 MW, 7 MW response



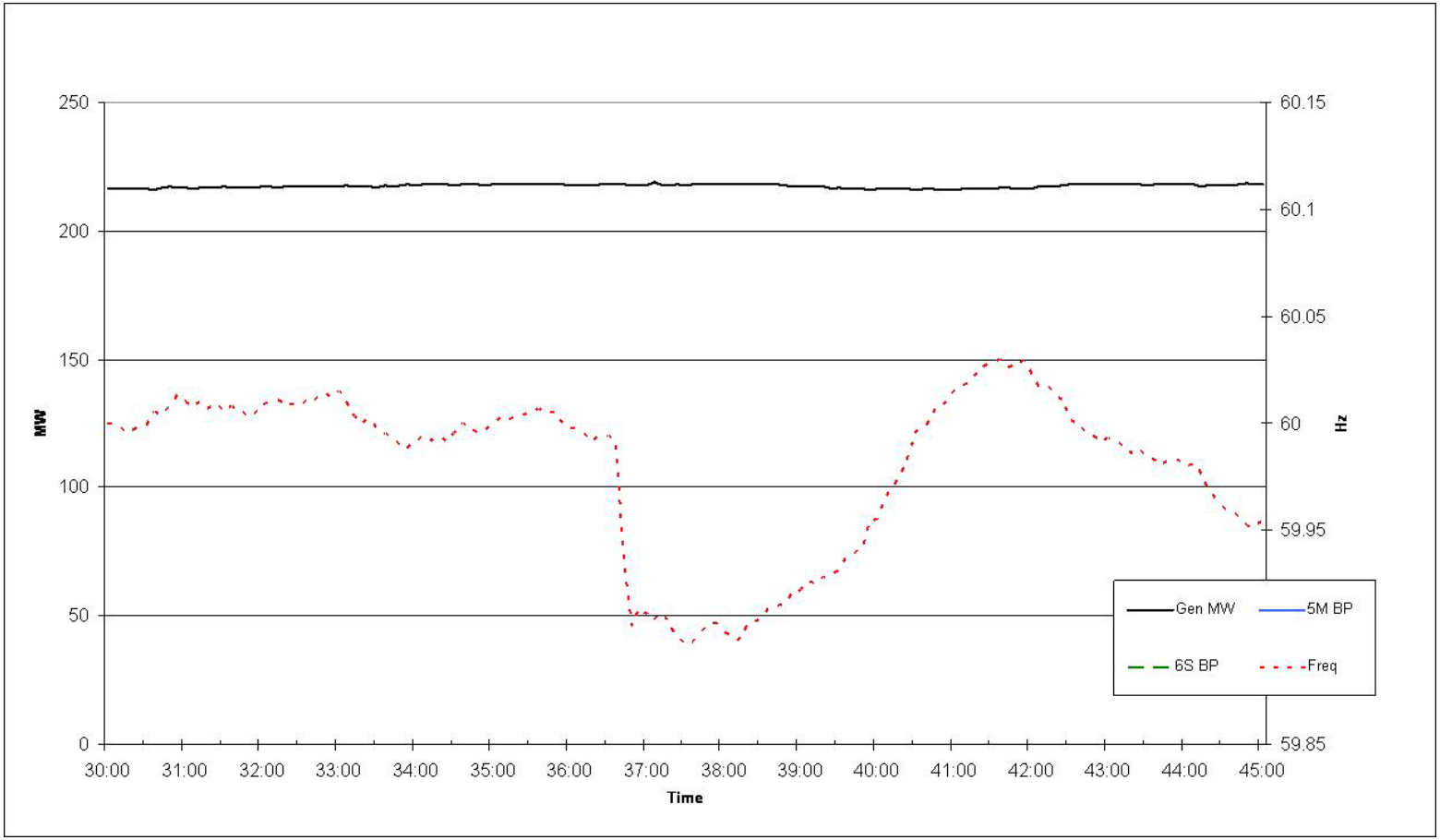

# Ex B Combined Cycle Unit Response
# April 27, 2011 HB17 frequency decline



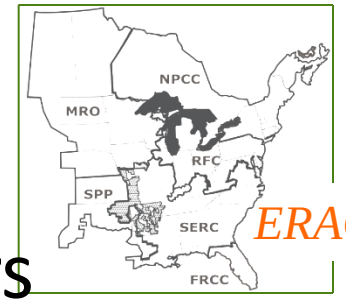

275 MW, expect 11 MW




# Ex “C” Combined Cycle Unit Response
# April 27, 2011 HB17 frequency decline

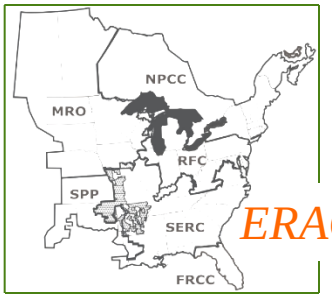



300 MW, expect 6 MW, no response

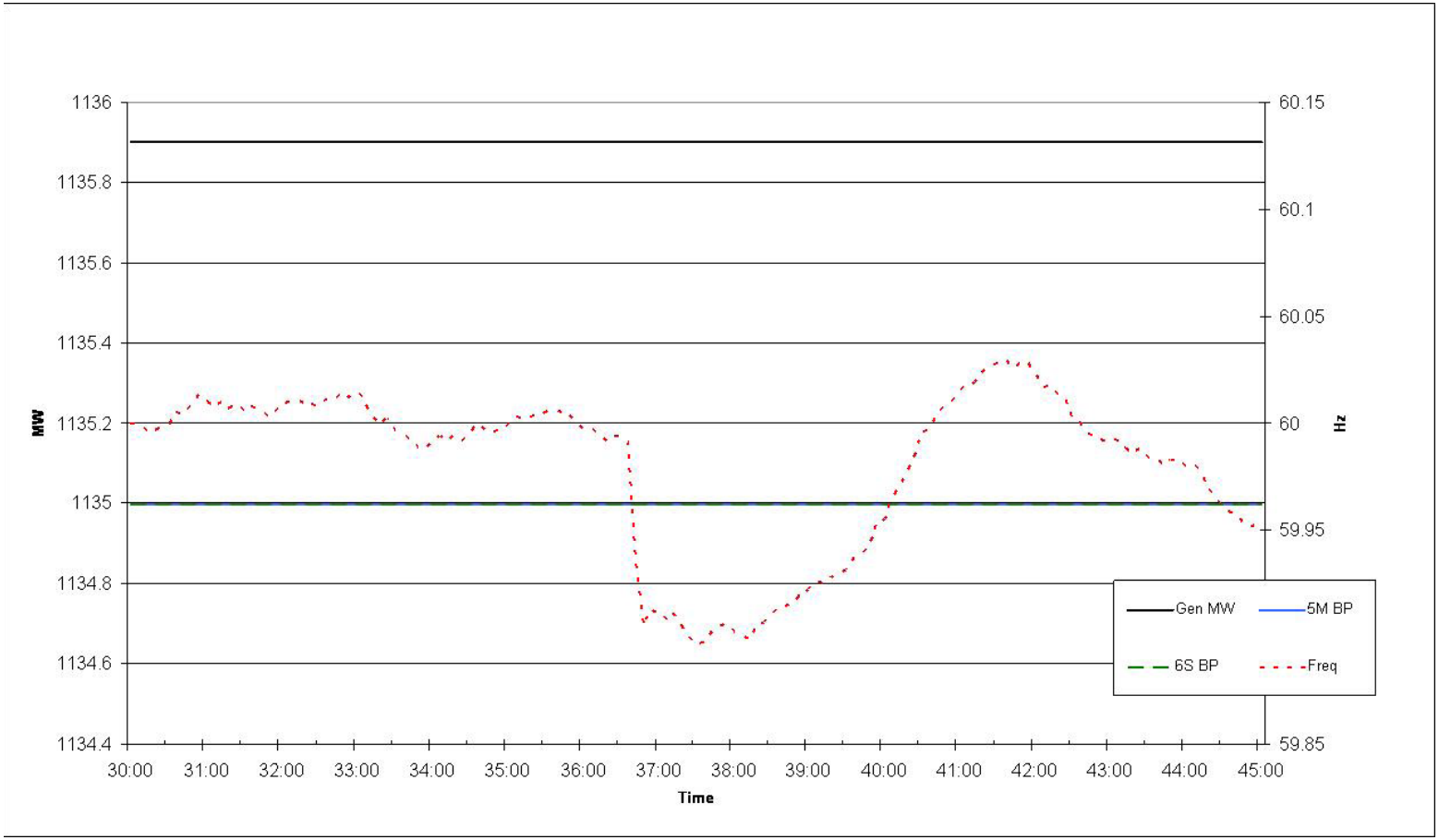



# Nuclear Generating Unit Governors

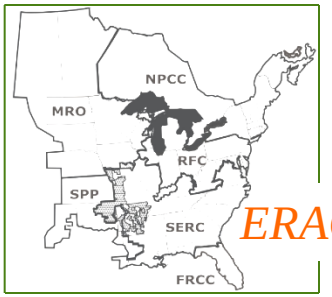
- Modeling issues brought to attention of ERAG Management Committee-NRC Rules for nuclear primary response
- Nuclear unit governors generally do not provide primary frequency response in Eastern Interconnection (near Max P and license requirements)
- 2010 ERAG Dynamic Model Series governor representations updated to reflect status (generally disabled governor action)



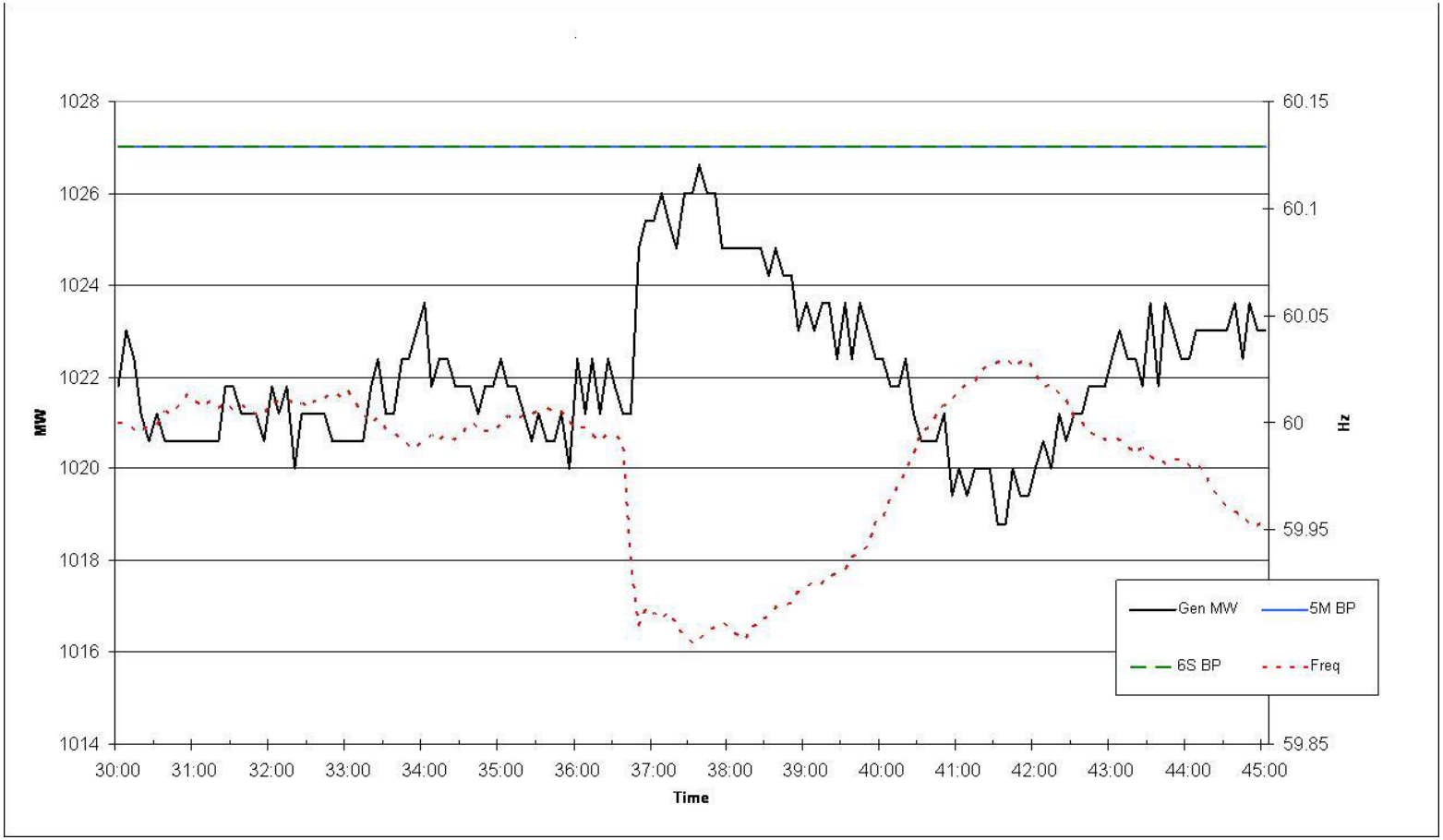

# Ex "A" Nuclear Generating Unit Response
# April 27, 2011 HB17 decline



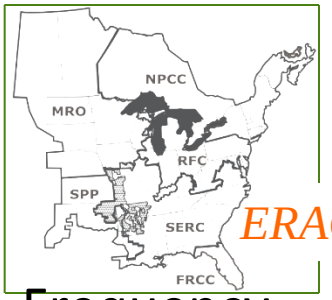

1,150 MW, no response



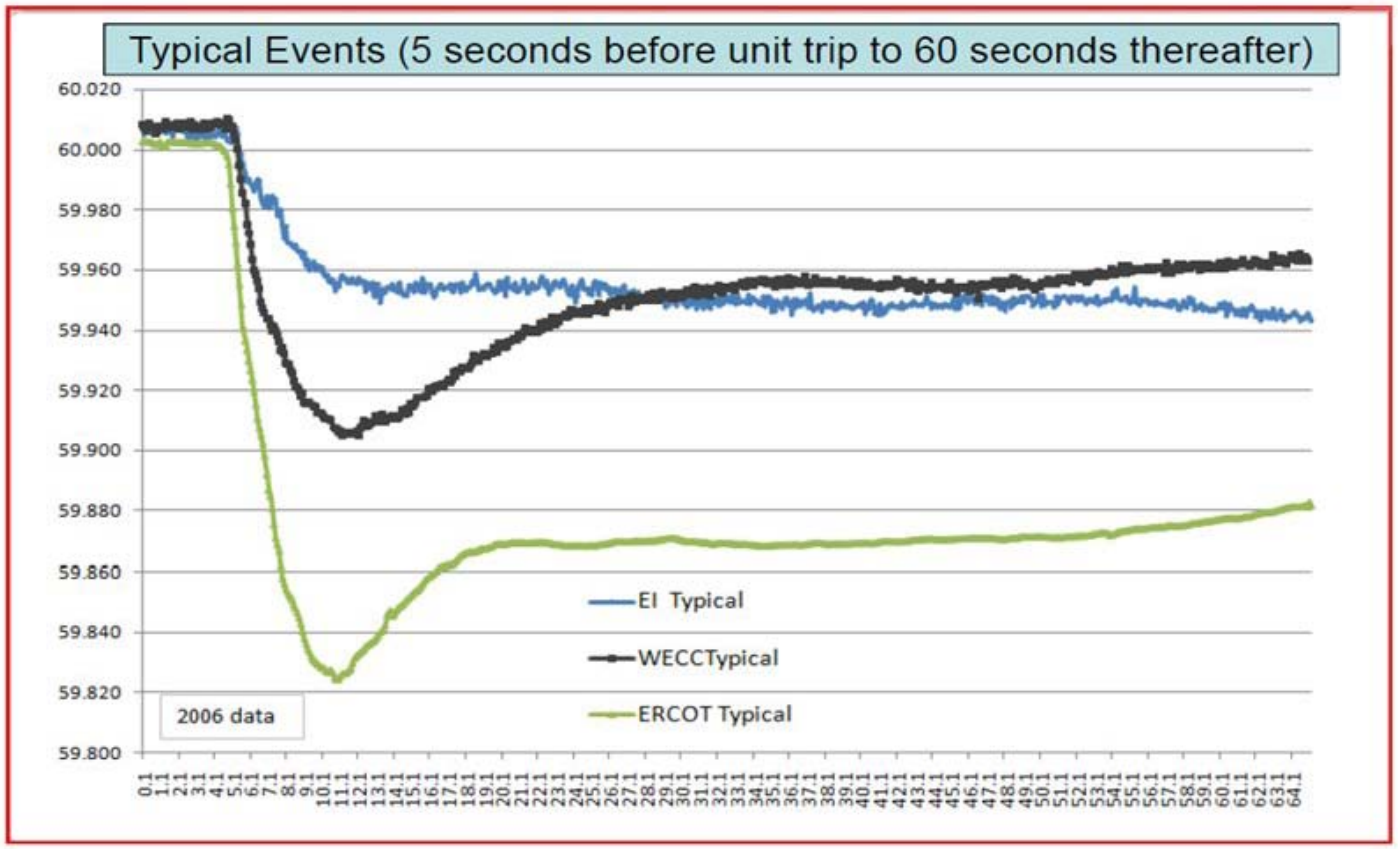

# Ex “B” Nuclear Generating Unit Response
# April 27, 2011 HB17 decline

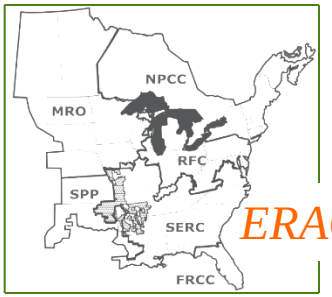



1,040 MW, 4 MW response

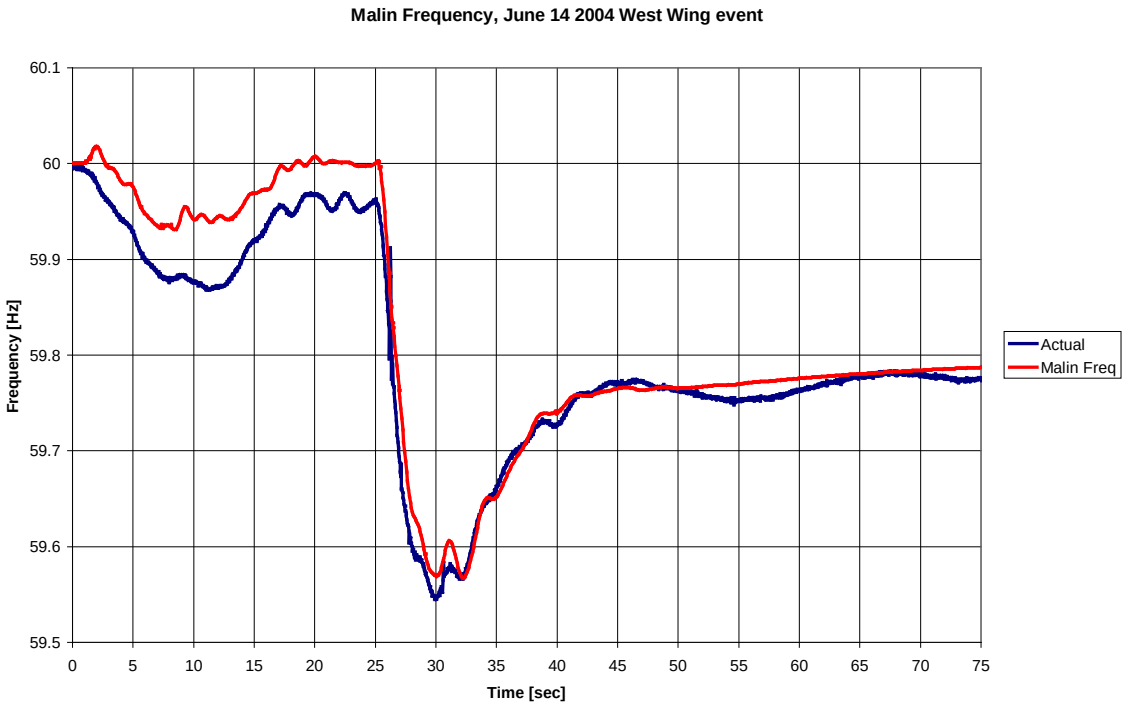



# Comparison of Eastern-Western and Texas Interconnection Frequency Response



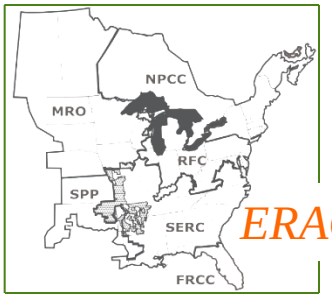


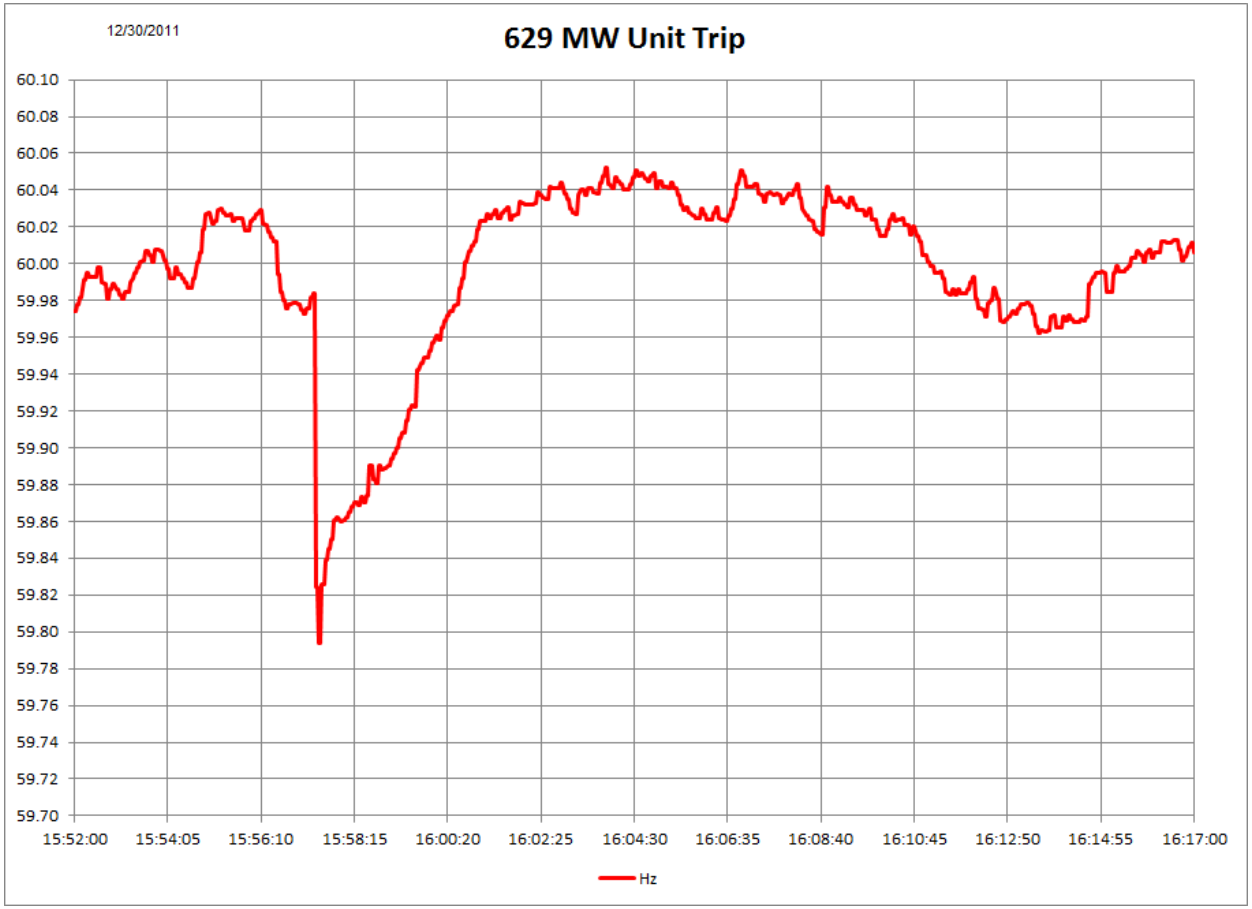

# Example: WECC



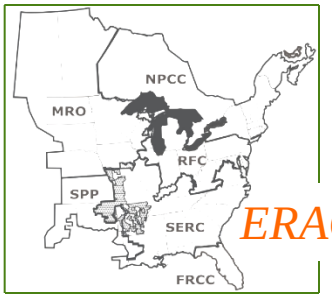

4,000 MW Loss

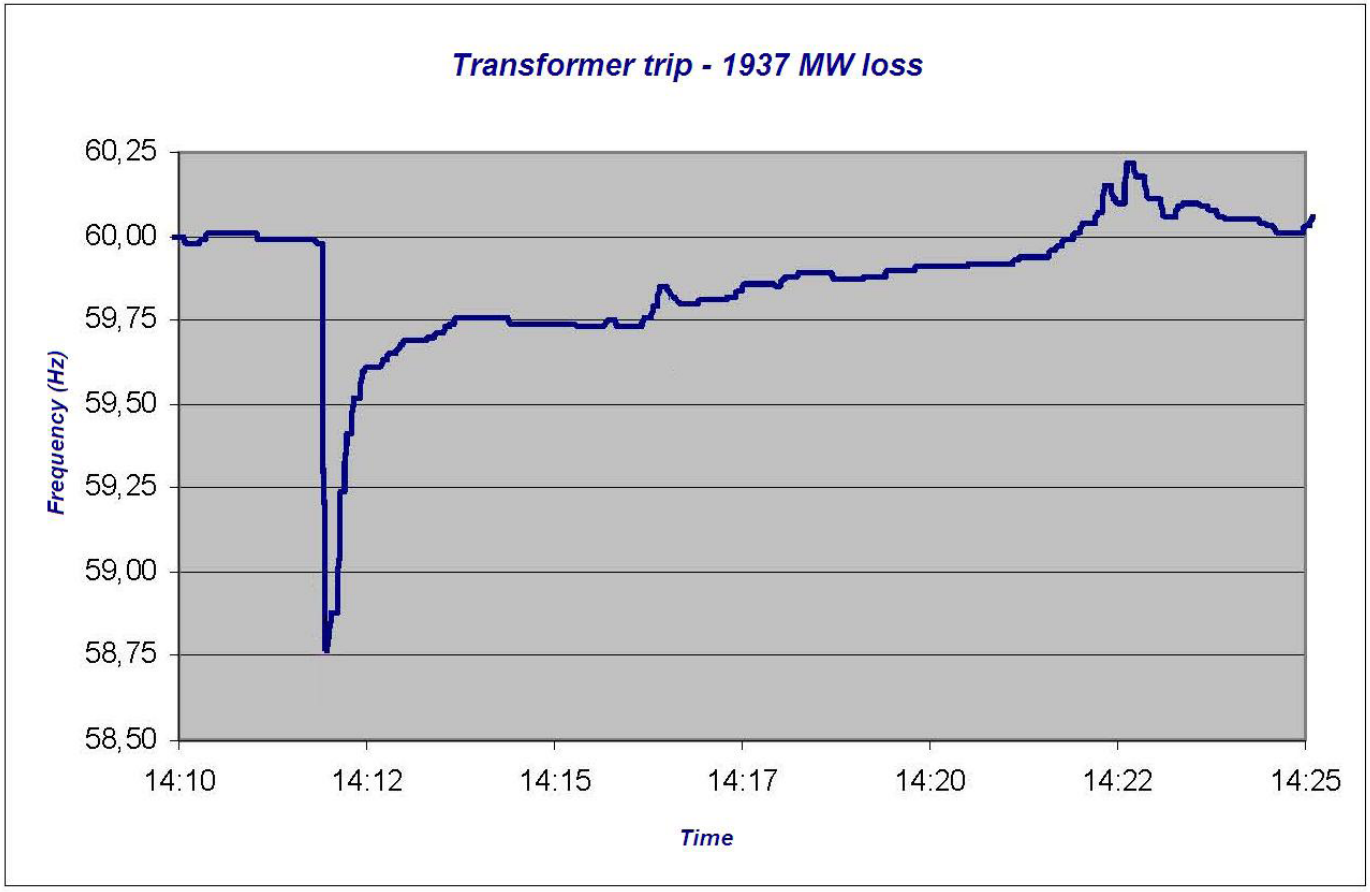
# ERCOT Typical Frequency Response

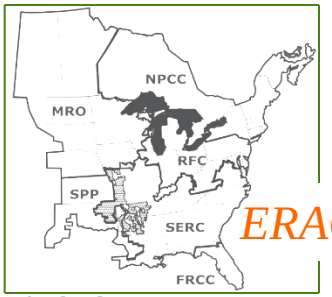


# Quebec Interconnection Example

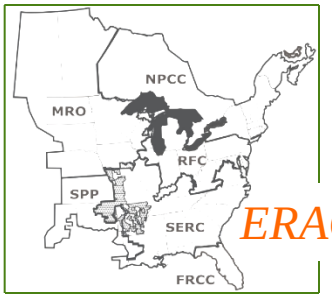




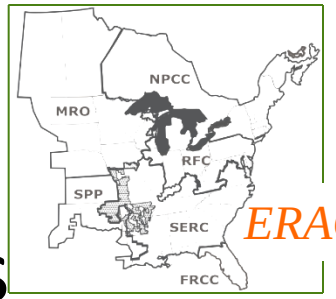

# Variable Generation Modeling Concerns

- Wind & Solar Generating Facilities
  - Plant output not under operator control
  - Improved dynamic models under development
  - Proprietary models restrict information sharing



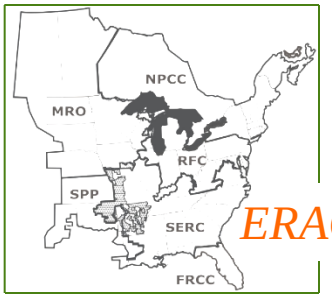

# Aspects of Generation Modeling Improvements

- Verification:
  - Data is accurate
  - All necessary parameters provided
  - Up-to-date
- Validation:
  - Data and model accurately replicate system response of equipment to an event
  - Equipment properly described
  - Equipment operation properly included
  - Often do not take into account the coordination and timing between governor models and other generating plant controls and systems.



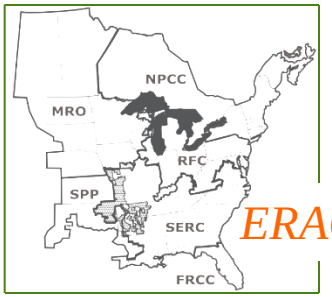

# ERAG outreach and Next Steps

- Detailed sessions-NERC Workshop (NERC coordinates), Sessions in the Reliability Regions to stakeholders (ERAG Management Committee coordinates)
- Focus on improvements in generation models
- Audience:
  - generator owners,
  - regional and sub-regional transmission planners,
  - computer model (software) vendors,
  - research consultants
- Data comes from facility owners (generator owners)
- Planners incorporate information into models
- Software model capability is dependant on vendors
- Researchers develop/update numerical methods for approximating system behaviour




# Contacts

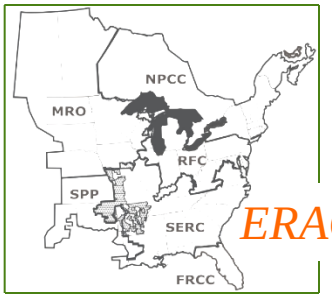
- For more information or assistance with technical requirements contact your region's Management Committee representative :
  - FRCC: Vince Ordax, vordax@frcc.com
  - MRO: Salva Andiappan, sr.andiappan@midwestreliability.org
  - NPCC : Paul Roman, proman@npcc.org
  - RFC: John Idzior, john.idzior@rfirst.org
  - SERC: Joe Spencer, jspencer@serc1.org
  - SPP: John Mills, jmills@spp.org




# Eastern Interconnection System Modeling – need for good models

## NERC Modeling Workshop, May 2-3, 2012

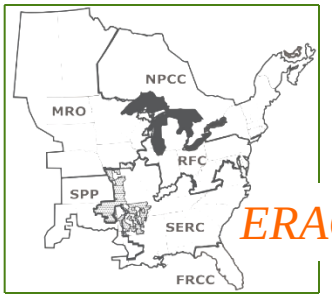
Dan Rochester – Manager, Reliability Assessments, IESO




# Goals of the ERAG presentations

Audience will have a better understanding of:

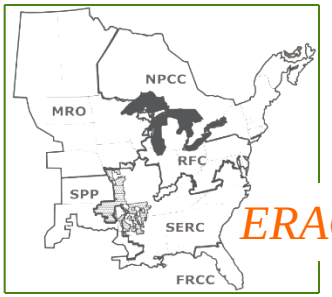
- Reliability-related needs for good interconnection-wide models
- Problems with current models
- Broad areas for improvement - initial focus on generation data
- Action plan for improvement – ERAG contacts, activities and timing




# ERAG

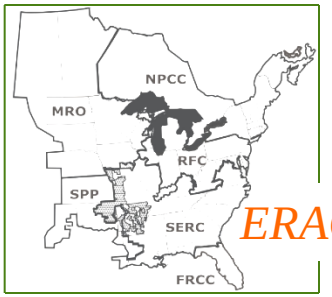
- Eastern Interconnection – largest of four NERC interconnections (others are WECC, ERCOT and Quebec)
- ERAG formed in 2006 under agreement between the six regional entities
  - Management Committee
  - Multiregional Modeling Working Group
  - Seasonal and Future Assessment Study Steering Committees





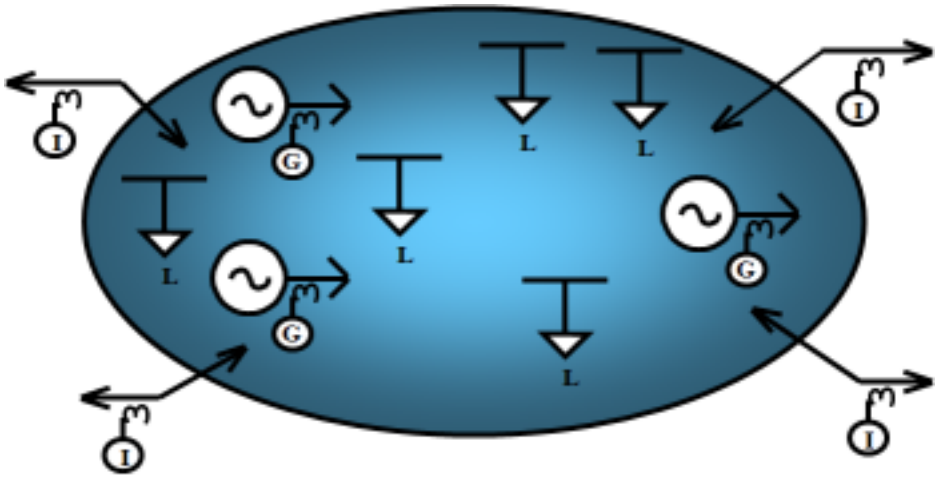

# Power System models

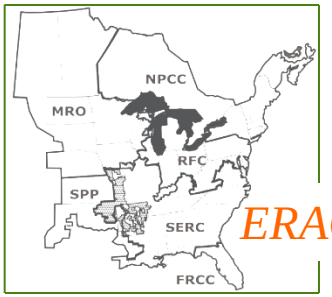
- Complex computer models which represent power system topology, load, generation, dispatch, and interchange
- Used to maintain and enhance reliability through simulation of the power system over various timeframes (applied for operation, short-term planning and long-term planning)
- Typically take one of two forms: Steady State and Dynamics




# Steady State models

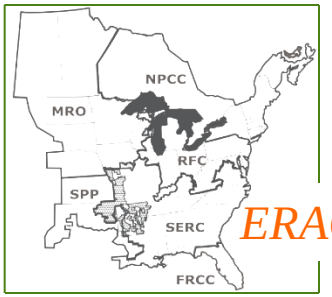
- Steady state models (powerflows or loadflows) are a representation of the power system developed to analyse the performance under static conditions
- Important to get right – steady state models form the base for dynamics cases
  - Alignment of data with actual system parameters is critical,
  - System to system alignment too






# Steady State models -Applications

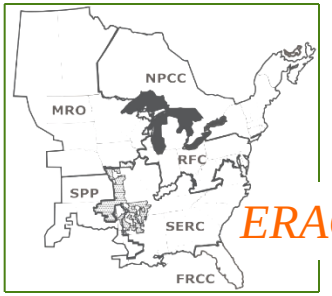
- Multi-regional Modeling Working Group Base Cases—(Industry use cases for various applications)- peak load seasonal, short-term, mid-term, long-term future, light load.
- Used for Eastern Interconnection Inter-regional assessment studies
- NERC Interchange Distribution Calculator (IDC)—Uses MMWG cases for network representation in IDC.
- Used for “outside world” representation in some Energy Management Systems.




# Dynamics models

- Dynamics models look at system response to events (perturbations) over varying timeframes:
- Transient stability: 1/10 second to 20 seconds
- Mid-term dynamics: >20 seconds
- Long-term dynamics: > 2 minutes

# POWER SYSTEM STABILITY




**Switching Transients**

- Voltage Stability
- Rotor Angle Stability
- Small-Signal Stability
- Frequency Control and Stability

**Subsynchronous Resonance**

**Transient Stability**

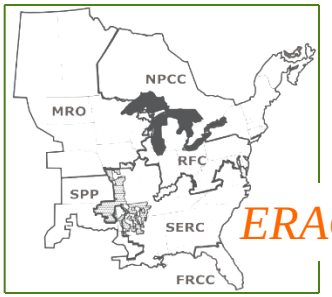
**Small Signal Stability**

**Long-term Dynamics**

$10^{-6}$ $10^{-5}$ $10^{-4}$ .001 .01 .1 1 10 100 1000 $10^{4}$

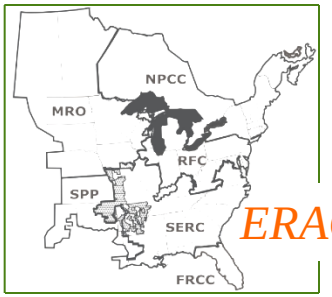
1 cycle 1 minute 1 hour

**TIME (seconds)**



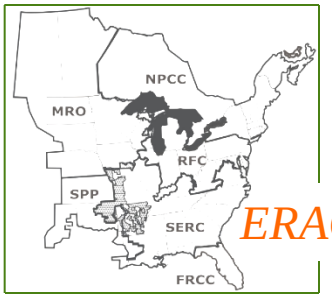

# Control System Types-Time Frames

| Control Means | Response | Effectiveness |
|---|---|---|
| Generator Inertia | Instantaneous | Insufficient |
| Load (MW/Hz) | Instantaneous | Insufficient |
| UFLS | < 1 sec | Locational |
| Over/Under Trip | < 1 sec | Effective but potential to overshoot |
| Governor Resp. | 1 – 30 sec | Problems with matching actual operation to expected |
| AGC | seconds -> minutes | May be capacity limited—coordinated with other controls |
| Op Intervention | > minutes | Too slow |



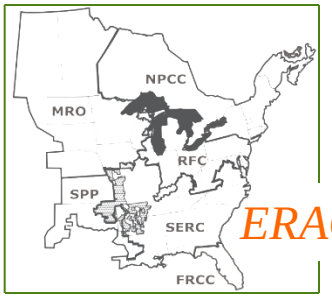

# Importance of good models

- ERAG's initial purpose was the development of an interconnection-wide model by combining detailed regional models
- Need is now emerging for enhanced interconnection-wide models suitable for reliability studies
- NERC's needs (initial focus from 11 item list)
  - frequency response analysis
  - sensitivity studies (especially extreme contingencies)
  - small signal analysis
  - forensic analysis of disturbances



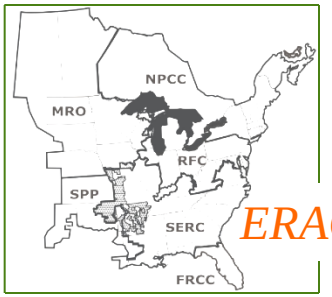

# Importance (cont'd)

- Planners needs
  - Generator interconnection studies (drives need for 5 year look-ahead)
  - Coordinated reliability studies – supporting NERC TPL standards
  - Identification of facilities that may limit
    - ✓inter-regional transfer capability
    - ✓interface limits




# Importance (cont'd)

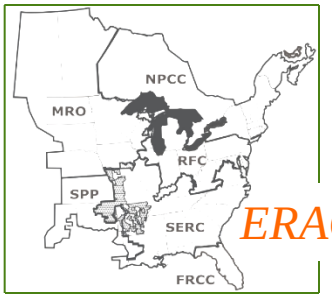
- Benefits to participants: greater reliability, less conservative plans and operational limits →more opportunities
- Compliance with MOD standards
- Small stuff matters – data providers need to work with those who can facilitate understanding
- Achieving improvements requires effort: better models → more testing of equipment may be needed from facility owner




# Steady state model data

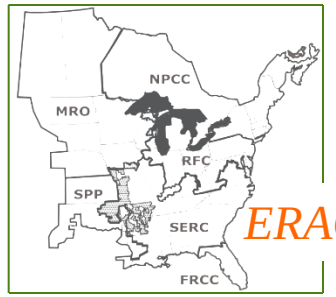
- Generation: real and reactive power output, voltage schedules
- Transmission network: line impedance and charging, transformer impedances and tap positions, reactive power devices (shunt and series) and operating status
- Load: total system, bus level load, real and reactive power (power factor)

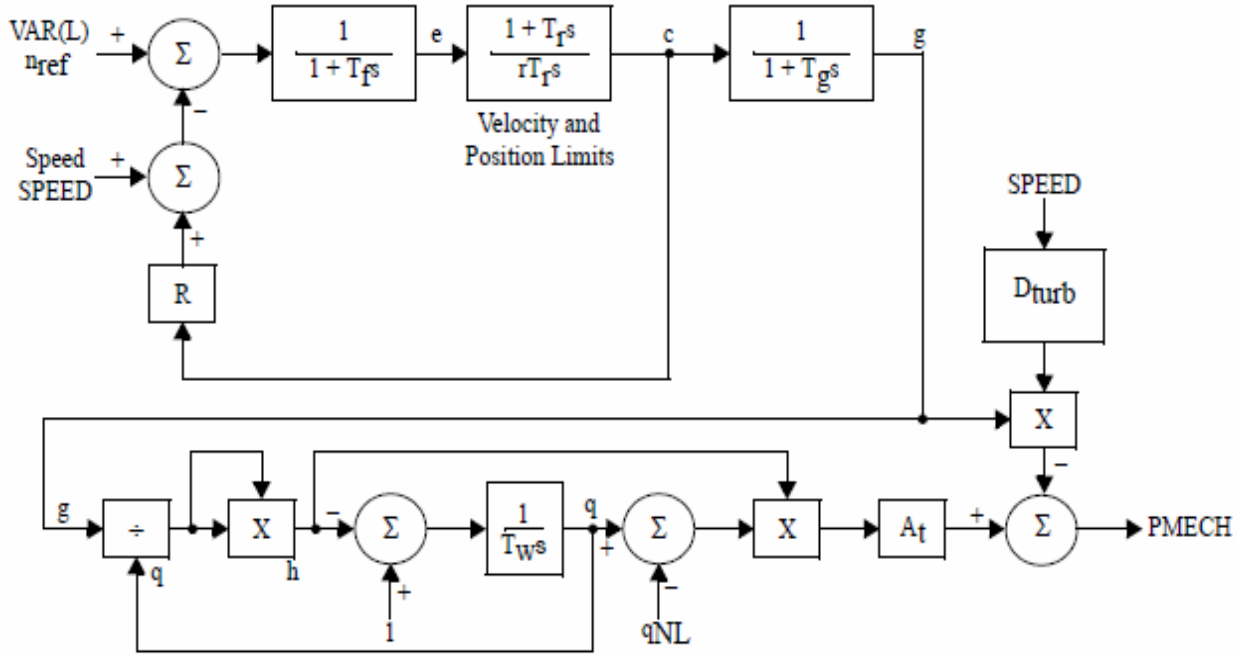
# Dynamics models: Generation data




- For dynamics (transient) models need status, operational and control parameters:
  - Exciters, including over-excitation limiters, under excitation limiters
  - Governor models reflect control mode, turbine control interaction/override,
  - Power system stabilizers,
  - Current compensators, etc
- Typically provided via block diagrams

# Sample dynamics model: HYGOV governor for hydraulic units

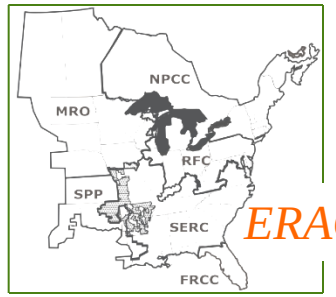


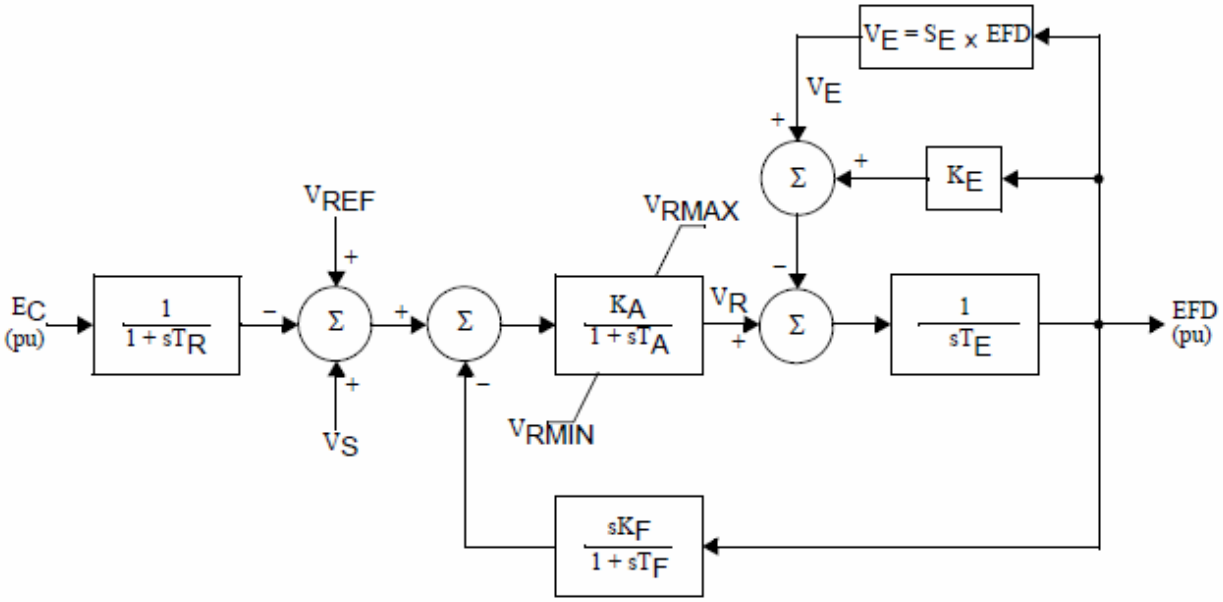




Model Parameters:

- nref: Speed reference
- R: permanent droop
- r: temporary droop
- TW (>0) water time constant
- Tf (>0) filter time constant
- Tg (>0) servo time constant
- Tr (>0) governor time constant
- At: turbine gain
- Dturb: turbine damping
- c: desired gate
- e: filter output
- g: gate opening
- h: turbine head
- q: turbine flow
- qNL: no power flow

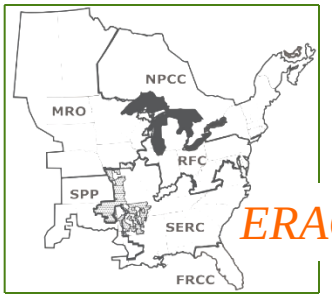
# Sample dynamics model: IEEET1 excitation system



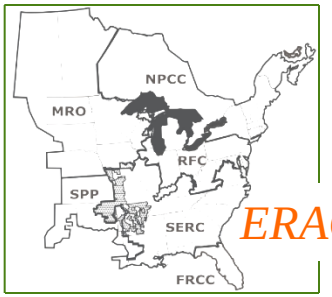

## Model Parameters:

- EFD: Exciter output
- VR: Regulator output
- SE: Saturation function

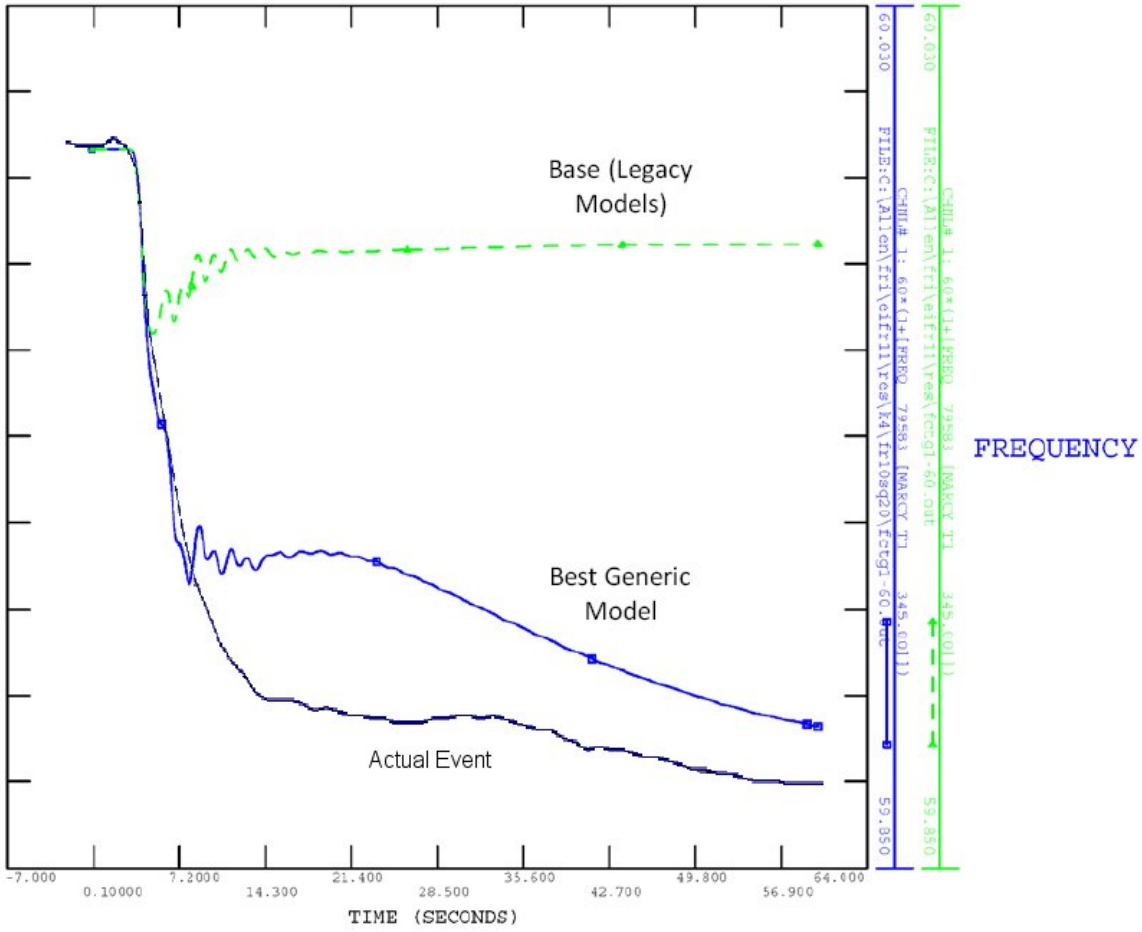



# Dynamics models: Other data

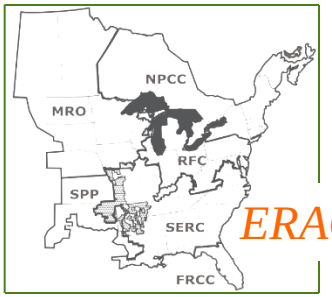
- need status, operational and control parameters
  - **System devices**: static var compensators, DC equipment and controls, flexible AC transmission system (FACTS)devices
  - **Loads**: motors and lighting
  - **Protection systems**: special protections systems (SPS), remedial action schemes (RAS), circuit protection settings, under-frequency or under-voltage relaying, circuit breaker operating times




# So what's the problem

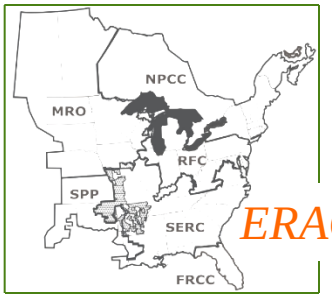


# Problems with current models



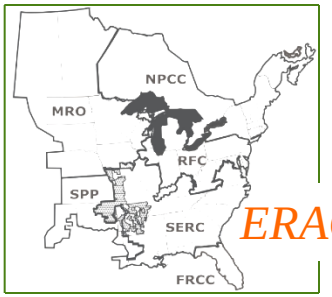

- ERAG's interconnection wide model needs to adequately mimic actual system frequency response
  - Can't make perfect but can improve
  - Multi-pronged approach toward initial improvements

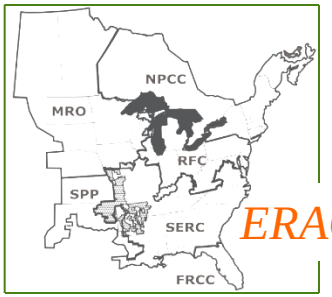
# ERAG modeling focus




- Change management to reduce recurrence of model errors
- Address generation netting and equivalence issues
- Engage in NERC activities (Model Validation TF, standards development)
- ERAG outreach to planners, data suppliers, model vendors and consultants
- Validate dynamics models of generation
- Improve generator and load models
- Learn from others: WECC, ERCOT

# Questions????






# Contacts

- For more information or assistance with technical requirements contact your region's Management Committee representative :
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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Cyber Attack Task Force

## Final Report

Board of Trustees Accepted: May 9, 2012

RELIABILITY | ACCOUNTABILITY



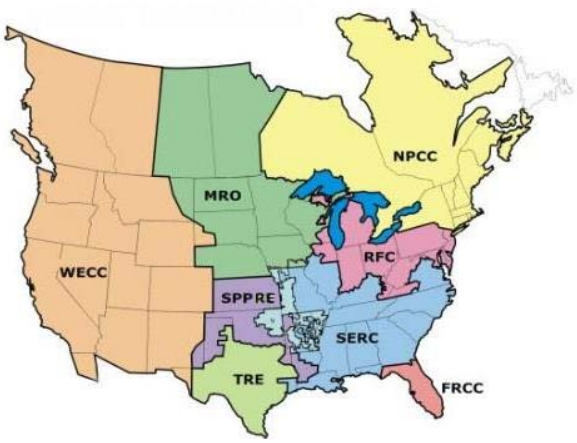



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Atlanta, GA 30326
404-446-2560 | www.nerc.com

## NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to enhance the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the BPS; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American BPS, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the BPS within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.




| Table A: NERC Regional Entities | |
|---|---|
| **FRCC**<br>Florida Reliability Coordinating Council | **SERC**<br>SERC Reliability Corporation |
| **MRO**<br>Midwest Reliability Organization | **SPP**<br>Southwest Power Pool, Incorporated |
| **NPCC**<br>Northeast Power Coordinating Council | **TRE**<br>Texas Reliability Entity |
| **RFC**<br>Reliability*First* Corporation | **WECC**<br>Western Electricity Coordinating Council |

**Note:** *The highlighted area between SPP and SERC denotes overlapping regional area boundaries: For example, some load serving entities participate in one region and their associated transmission owner/operators in another.*

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NERC's reliability standards are also mandatory in Nova Scotia and British Columbia. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

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# Executive Summary

The North American bulk power system (BPS) is one of the most critical of infrastructures and is vital to society in many ways. The electric power industry has well-established planning and operating procedures in place to address the "normal" emergency events (e.g., hurricanes, tornadoes, and ice storms) that occur from time to time and disrupt electricity reliability[2]. However, the electricity industry has much less experience with planning for and responding to high-impact events that have a low probability of occurring or have not yet occurred.

To help the electricity industry better understand these low probability risks, in June 2010, NERC and the U.S. Department of Energy issued a report titled, "*High-Impact, Low-Frequency Event Risk to the North American BPS*"[3]. Subsequently, the NERC board approved a *Coordinated Action Plan*[4] under the leadership of the NERC Technical Committees to establish four Task Forces needed to address this work. This report provides the conclusions of one of them – the Cyber Attack Task Force (CATF).

This effort has challenged the CATF in a number of ways.

- The industry already recognizes cybersecurity risks, in part by addressing the requirements of the NERC Critical Infrastructure Protection standards CIP-002 – CIP009. As a result, some entities may feel they are already prepared.
- While entities are challenged on a daily basis by new cybersecurity vulnerabilities and attempted intrusions, a successful coordinated cyber attack affecting the North American bulk power system has not yet occurred. Therefore, it is difficult to confidently determine the potential impact on the reliability of the bulk power system and what additional actions may need to be taken.
- Through the course of its work, the CATF shared sensitive information related to threats, vulnerabilities, and impacts. While this information was essential to develop the recommendations found in this report, the CATF could not include these details in this public report.

The CATF has recognized these challenges and through this report offers electricity industry owners and operators (entities) a number of suggestions and recommendations. The report highlights 8 key recommendations that will help entities prevent, deter, detect, and respond to a coordinated cyber attack and further enhance the resilience of the bulk power system.

[2] Ref. NERC Adequate Level of Reliability http://www.nerc.com/docs/standards/Adequate_Level_of_Reliability_Defintion_05052008.pdf
[3] Ref. High Impact Low Frequency report http://www.nerc.com/files/HILF.pdf
[4] Ref. Coordinated Action Plan http://www.nerc.com/docs/ciscap/Critical_Infrastructure_Strategic_Initiatives_Coordinated_Action_Plan_BOT_Apprd_11-2010.pdf

## Defining a Coordinated Cyber Attack

The CATF adopted an approach that assumed a coordinated cyber attack has occurred. It did not attempt to determine the likelihood of such an attack either today or at some time in the future. The CATF also did not attempt to determine which functional entities[5] might be more susceptible or vulnerable to attack. The CATF determined that it was more important to assume that an attack has occurred, and consider what actions need to be taken to prevent, deter, detect, and respond.

The CATF adopted the following scenario to guide their work:

An organized cyber disruption disables or impairs the integrity of multiple control systems, or intruders take operating control of portions of the bulk power system such that generation or transmission system are damaged or operated improperly.

1. Transmission Operators report unexplained and persistent breaker operation that occurs across a wide geographic area (i.e., within state/province and neighboring state/province).
2. Communications are disrupted, disabling Transmission Operator voice and data with half their neighbors, their Reliability Coordinator, and Balancing Authority.
3. Loss of load and generation causes widespread bulk power system instability, and system collapse within state/province and neighboring state(s)/province(s). Portions of the bulk power system remain operational.
4. Blackouts in several regions disrupt electricity supply to several million people.

## Enhancing Resilience

"Resilience" is generally defined as the ability to recover or adjust to misfortune or change. More specifically, the ASIS SPC.1-2009 standard on Organizational Resilience[6] defines, "Resilience is the ability of an organization to resist being affected by an event or the ability to return to an acceptable level of performance in an acceptable period of time after being affected by an event." In recent years, in the context of strategies needed to enhance the reliable operation of critical infrastructures, resilience has come to be valued as much as protection. But what exactly is meant by resilient critical infrastructures? How is resilience measured and how much is needed?

### Infrastructure Resilience

Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event.

[5] E.g., Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator

[6] ASIS SPC.1-2009, http://www.asisonline.org/guidelines/ASIS_SPC.1-2009_Item_No._1842.pdf

In October 2010, a study group[7] of the National Infrastructure Advisory Council issued its report "A Framework for Establishing Critical Infrastructure Resilience Goals[8]". The report provides a broader construct for resilience originally conceived by resilience expert Stephen Flynn. The construct is based on four features organized in a sequence of events prior to, during, and after a severe emergency event.

NERC's Severe Impact Resilience Task Force[9] has proposed a number of recommendations and considerations from the perspective of the reliable operation of the bulk power system, regardless of the cause of the emergency event. The CATF has focused its efforts on the measures that can be taken to prevent, deter, detect, and respond to a coordinated cyber attack from the perspective of the assets, systems, and networks used to monitor, operate and control the bulk power system such as Supervisory Control and Data Acquisition (SCADA), energy management systems (EMS), and generation management systems (GMS).




[7] The NIAC Study Group included a number of representatives from the electricity industry, including several members of the Electricity Sub-sector Coordinating Council.

[8] Ref. http://www.dhs.gov/xlibrary/assets/niac/niac-a-framework-for-establishing-critical-infrastructure-resilience-goals-2010-10-19.pdf

[9] Ref. report *Severe Impact Resilience: Considerations and Recommendations* http://www.nerc.com/filez/sirtf.html

## Key Recommendations

The CATF has considered what aspects of cybersecurity would be particularly challenged through a coordinated cyber attack and considered options to protect the assets, systems, and networks that are critical to the reliable operation of the bulk power system. The following summarizes the key recommendations of this report that are described in the body of the report in further detail. While some of the recommendations identify areas that require further study coordinated through NERC's Technical Committees, others recommend that entities take certain actions to enhance their ability to prevent, deter, detect, and respond to a coordinated cyber attack.

1. **Continue Work on Attack Trees** – A separate working group under NERC's Critical Infrastructure Protection Committee (CIPC) should be established to further develop attack trees with the goal of populating the nodes, performing detailed analysis, and providing recommendations to industry from this analysis.

| Prevent Deter | Detect | Respond |
|---|---|---|
| ✔ | | |

2. **Continue to Develop Security and Operations Staff Skills to Address Increasingly Sophisticated Cyber Threats** – Entities should develop strategies to attract cybersecurity talent and further develop the knowledge, skills, and abilities of existing staff to address increasingly sophisticated cyber threats and technology challenges that accompany grid modernization efforts.

| Prevent Deter | Detect | Respond |
|---|---|---|
| ✔ | ✔ | |

3. **Augment Operator Training with Cyber Attack Scenarios** – Several cyber attack scenario templates are included in Appendix C of this report. Entities should consider enhancing training to incorporate cyber attacks that raise operator awareness for a coordinated cyber attack.

| Prevent Deter | Detect | Respond |
|---|---|---|
| | ✔ | ✔ |

4. **Conservative Operations** – The *Severe Impact Resilience: Considerations and Recommendations* report prepared by the Severe Impact Resilience Task Force offers a number of recommendations regarding conservative operations. Entities should review this report and consider the practices that would apply to a coordinated cyber attack scenario.

| Prevent Deter | Detect | Respond |
|---|---|---|
| | | ✔ |

5. **Conduct Transmission Planning Exercise** – Working with Department of Energy's national labs and a pilot group of electricity utilities, a transmission planning exercise should be coordinated by NERC to simulate a coordinated cyber attack that creates a cascading event and blackout. The event should attempt to

| Prevent Deter | Detect | Respond |
|---|---|---|
| ✔ | | ✔ |

identify the point at which current transmission planning criteria is exceeded and allow for dynamic resilience and mitigation exercise.

6. **Continue to Endorse Existing NERC Initiatives That Help Entities Prepare for and Respond to a Cyber Attack –** Entities should consider greater participation and support of NERC's initiatives that can help the industry with cyber attack identification, defense, and response. Three examples are**:**

| Prevent Deter | Detect | Respond |
|---|---|---|
| ✔ | | ✔ |

   - Cyber Readiness Preparedness Assessments (CRPA)
   - NERC Grid Security Exercise
   - ES-ISAC portal and collaboration

7. **Increase Awareness for Department of Energy Initiatives –** The Energy Sector Control Systems Working Group recently released the *Roadmap to Achieve Energy Delivery System Cybersecurity*. NERC's Critical Infrastructure Protection Committee should review these initiatives and support further development and implementation of these initiatives to help ensure protection of critical systems supporting bulk power system.

| Prevent Deter | Detect | Respond |
|---|---|---|
| ✔ | | |

8. **Continue to Extend Public / Private Partnership –** Entities should review their cyber incident response plans to ensure an appropriate mix of operational, security, technical, and managerial staff are aware of how they need to evaluate, respond, and make timely decisions to slow or stop a coordinated cyber attack. This could include participating in ES-ISAC and government sponsored programs to share security-sensitive or classified information regarding cyber threats and vulnerabilities. In the event standard information sharing protocols are unavailable (e.g. between utilities, ES-ISAC, etc), alternative methods need to be defined.

| Prevent Deter | Detect | Respond |
|---|---|---|
| | | ✔ |

## Introduction

A highly coordinated and structured cyber, physical, or blended attack on the bulk power system, could result in long-term, difficult to repair damage to key system components in multiple simultaneous or near-simultaneous strikes. Unlike "traditional," probabilistic threats (i.e. severe weather, human error, and equipment failure), a coordinated attack would involve an intelligent adversary with the capability to bring the system outside the protection provided by current planning and operating practices. An outage could result with the potential to affect a wide geographic area and cause large population centers to lose power for extended periods.

Security practitioners have always found it difficult to provide convincing demonstrations that the countermeasures they deploy are effective in preventing an attack. It is fundamentally difficult to provide conclusive proof of why an event did not happen.

Though no such attack has been successfully executed to date on the North American grid, the bulk power system remains an attractive target for acts of both physical and cyber terrorism. Goals of these adversaries are wide-ranging and could involve extortion, societal damage, and, in the case of state-sponsored attacks, acts of war.[10]

The purpose of the Cyber Attack Task Force (CATF) is to consider the impact of a coordinated cyber attack on the reliable operation of the bulk power system, and identify opportunities to enhance existing protection, resilience, and recovery capabilities.[11]

## Approach

The scenario itself allows for a consequence driven approach. The premise is that the outcome of the attack has unacceptable consequences. It is impossible to consider and evaluate every type of risk to the bulk power system. As a result, we focus on the risks that matter as defined by consequences.

To address the objectives and goals the task force utilized a combination of industry expertise (both IT and operational), discussions with federal agencies and law enforcement, and incorporated lessons learned from current and past initiatives.

In addition, the task force attempted to capture and catalog different attack paths that could be utilized to create specific results from the given scenario. In other words, leverage intelligence from the community of interest to define what a coordinated attack would look like. We started to capture the many steps associated with different attack paths in what is called an Attack Tree.

Security practitioners have always found it difficult to provide convincing demonstrations that the countermeasures they deploy are effective in preventing an attack. It is fundamentally

[10] High-Impact Low-Frequency Event Risk to the North America Bulk Power System (June 2010)

[11] NERC Scope – Cyber Attack Task Force

difficult to provide conclusive proof of why an event did not happen. This is one of the reasons that the task force did not focus on the adequacy of the NERC CIP standards to prevent a coordinated cyber attack. Instead the task force included references to the CIP standards, both approved and under development, along with other tools, processes and recognized standards and guidelines from ISA and NIST as part of the industry's defensive capabilities to combat a coordinated attack. This problem is exacerbated further when dealing with unprecedented or infrequent events. Yet the threat environment going forward is likely to demand and feature a capability to prevent attacks or mitigate their impacts through coordinated response and effective information sharing.

Attack Trees are constructed from the point of view of the adversary. Creating good Attack Trees requires "*we think like an attacker".* The task force did not focus on how to defend a utility's systems when the model was originally started. Instead the task force thought about what an attacker wants to achieve and ways to accomplish it. In this case, the attacker wants to achieve blackouts in several regions disrupting distribution supply to several million people[12]. This approach was useful as those engaged for the project have a very good understanding of the mechanics associated with the elements required to severely impact the bulk power system.

One of the constraints encountered by the task force is the sensitivity of the information being gathered and determining a way to translate from sensitive to public so the larger industry can benefit from subject matter expert recommendations. This situation manifested itself on numerous occasions from discussions with law enforcement and the intelligence community on threat actor capabilities to detailed steps captured in the Attack Trees.

[12] Ingoldsby, Terrance R., 2010 Amenza Technologies Limited: Attack Tree-based Threat Risk Analysis, page 2

# Adversaries, Motivations, and Capabilities

In the cyber realm, the ability to climb the line of consequences versus likelihood is very different than physical risks. The resources and requirements to execute an attack that can cause a catastrophic effect are much more available, and is really a matter of how an adversary chooses to manifest attack type or target selection. Attacker sophistication should be measured less in technical "craft" skills and more in terms of intent fitted to environment. Disrupting or hijacking system resources is one thing….destroying trust and confidence by poisoning data or compromising privacy information is another. [13]

The defense against a cyber attack scenario will include physical as well as cyber-based elements, some procedural and others involving strategic investments in physical infrastructure, capabilities, spares, and training.

There are a variety of interventions or attacks that adversaries might contemplate and each carries unique defensive planning and resource requirements. A holistic, tailored defensive posture prioritizes and balances these to achieve the optimal cost/benefit value delivery for the defender. The defense against a cyber attack scenario will include physical as well as cyber-based elements, some procedural and others involving strategic investments in physical infrastructure, capabilities, spares, and training.

There does not appear to be a universally accepted classification or grouping of advisories. Work done by the FBI, DHS, NERC, and security consulting groups with many years of experience do not all agree what the threat actor categories should be. In this report you will see references to Groups 1-3; High, Medium and Low Threat Actors; Criminals, Hackers, Hacktivists, Nation States, Organized Crime, Structured Criminals, Terrorists, and Foreign States. As you read about these groups from the different sources, the focus should be on intent and capabilities to conduct a coordinated cyber attack on the bulk power system. But also recognize that intent and capabilities can change very quickly.

Training offered as part of the Department of Homeland Security's Control System Security Program (CSSP) discusses three categories of threat actors: Group 1 Main Stream Threats, Group 2 Organized Threats, and Group 3 Terrorist and Nation State Threats

Group 1 is the largest threat group although they are typically not organized. These types of threats often compete for notoriety, fame, or personal research and members of this group can be anyone. There is some element of minor organization in this group, but historically the members of this group are lone actors. Often, as they become better known, and there is an increase in the demand for their services, both legal and illegal, their activity increases. It needs to be understood that there are capabilities within this group that can be used in the activities performed by group 2 and group 3 threat actors. Just because group 1 actors are not organized

[13] Likelihood and Consequences Chart – Mike Assante 2011

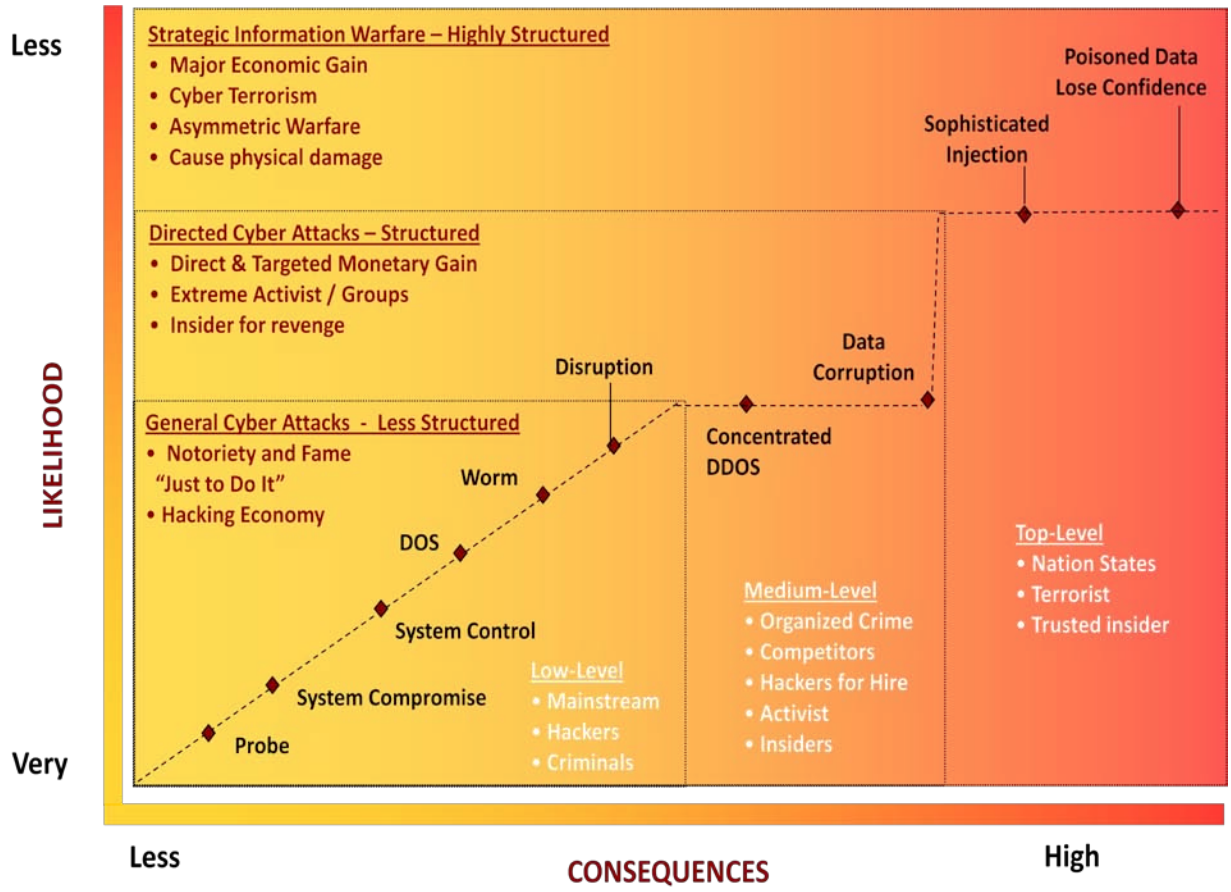
in numbers, and may not have a specific modus operandi or methodology, there is a good chance that unique capabilities exist that could be very useful in group 2 and group 3 activities.

Group 2 are more organized, and it is the organizational aspect that is cause for concern. By having a structure, this group can have membership elements that are diversified across a very large area, and may have access to disparate information systems that would normally be only accessible by a single actor. Often, collective intelligence is pooled together by group 2 members to help shape more effective and efficient attack strategies. Group 2 threats are most likely to develop specific target folders and use the information in those folders to plan, test, and perform targeted attacks.

The motivation for these attacks can be quite diversified, but it is generally observed that these attacks involve group level efforts supporting a common cause. Group 2 typically target a particular group or groups, and their motivation may be financial, revenge, theft of trade secrets or drawing attention to a cause (hacktivists). The capabilities in group 2 would be found useful in group 3 type activities, as group 2 factors often aggregate tools and methods to be more powerful. The end state of this aggregation may be attractive to group 3 actors (depending, of course, on what the goals are). Their attacks are more structured and sophisticated than group 1 attacks, but group 2 attacks often incorporate methods used by group 1. This would be expected considering that the attack lifecycle of target acquisition, system penetration, privilege escalation, and covert action is fairly ubiquitous across all group activities.

Group 3, asymmetric threats (often associated with terrorist or nation state), occurs when two forces of disproportionate size and capability are engaged in conflict. The goal of these types of attacks is to disrupt, terrorize or eliminate major aspects of society. Targets include financial institutions, political establishments, military organizations, and media outlets. Organizations involved in national security activities are also concerned about critical infrastructure, and how such threats could launch debilitating cyber attacks that include an impact on restoration and reconstitution activities. In addition to asymmetric threats, nation states that may have well-funded cyber warfare programs are also a concern.

Both asymmetric and nation state threats have significantly more resources than group 1 and 2 threats and as a result they can launch very sophisticated attacks. However, it should be understood that it is not unlikely for a group 3 actor to utilize tools, techniques, and procedures used by either group 1 or group 2. This reasoning could be extended to suggest that, when possible, group 3 actors will recruit the services of group 1 and 2 thread elements and capabilities. The impact or consequences of group 3’s attack could be catastrophic.




The risk equation that is often most appropriate for critical infrastructure is one that involves threat, vulnerabilities, and consequence. Using what are commonly known as 'threat curves', we can plot different types of threats and their associated elements against the likelihood of such activities happening. In its simplest form, we can plot consequence against likelihood and then plot the activities of the three types of groups discussed earlier.

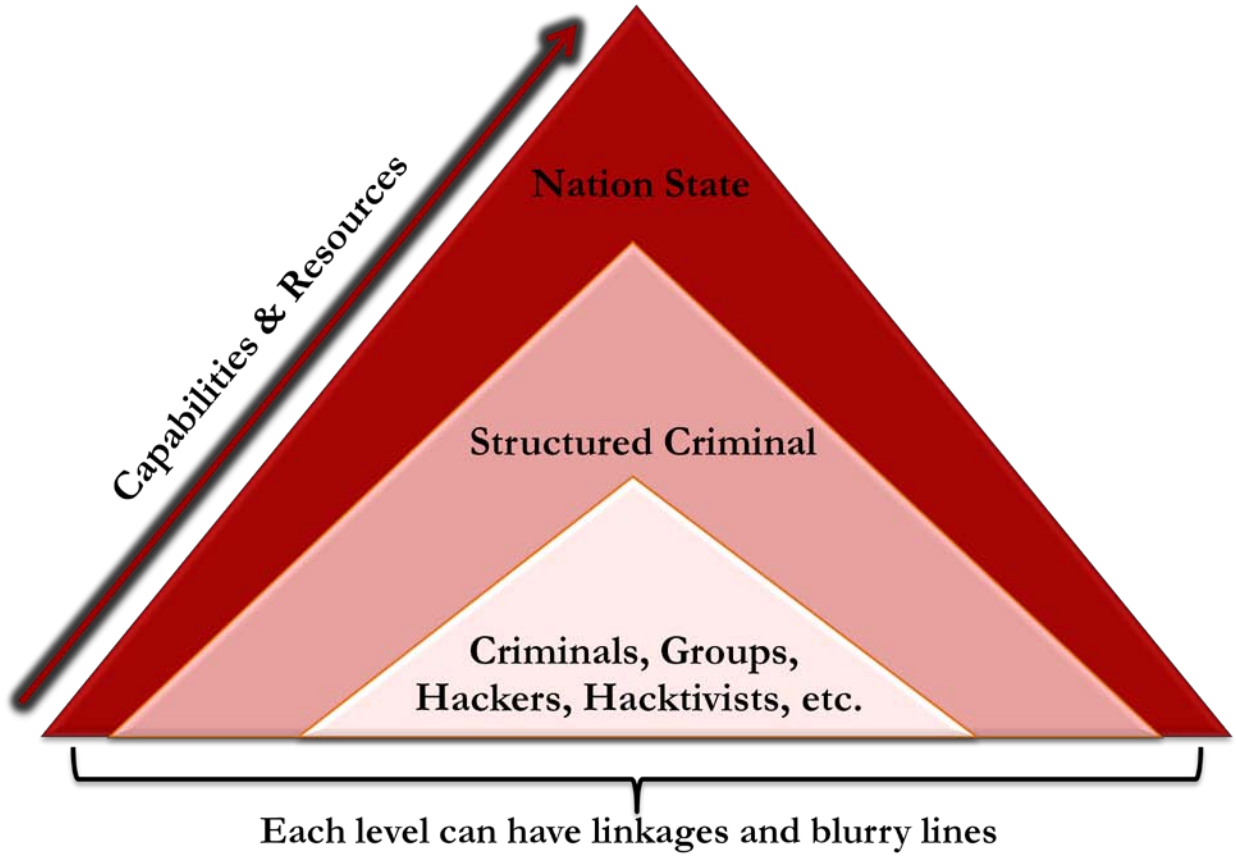
We notice from the graphic that the more benign activities would occur in the bottom left-hand corner of the graph with the most critical actions or consequences in the upper right. As the plot moves towards the top, the top right-hand element of the curve is referred to as the 'high impact low frequency' domain. This is the area of the graph containing the most severe consequences.

But looking at the way the curve starts in the bottom left-hand corner, we can see how the strategies of the group 1 actor curve up into the right. This is because we anticipate that the activities being performed in an attempt to generate greater consequence become more difficult to accomplish. Taking into consideration that group 1 type actors are usually lone actors, and if they do exist in small groups there is limited organization, the level of effort increases noticeably as they try to increase their attack complexity. This is not necessarily true if the lone actor is an insider. See the reference to insiders later in this document.

The curve flattens when it gets to the group 2 domain, the primary reason being that the characteristics of group 2 suggest that the organization and the cultural make up of the group

will have an ability to increase consequences without necessarily having any less likelihood of success. The reasons for this are many, but can include the fact that the group 2 structure facilitates for advanced reconnaissance and the development of target folders which would be used specifically to ensure there is enough intelligence to ensure successful attack. Group 2 may use elements and perhaps membership from group 1, but the motivations of group 2 combined with an advanced and collaborative technical capability results in an increase in consequence with no deterioration likelihood for success.

Lastly, group 3 is assumed to have very specific goals and intentions with regards to consequence. As these consequences are desired to be extreme, such as widespread economic impact and the degradation of recovery capabilities, the level of effort is significant. The interesting thing about group 3 activities in the high impact low frequency domain is that we could expect well-planned and well-funded cyber attacks to have cascading effects across critical infrastructure elements. Currently, there is an abundance of available information suggesting that national critical infrastructures have significant interdependencies and interconnectedness. The 2003 Blackout illustrated the interdependencies of critical infrastructure, and showcased how a catastrophic failure in one specific sector has extremely far-reaching results in others.




**Low Level Threat**

**Criminals, Hackers, Hacktivists**

- Can be less experienced
- Limited financial resources
- Opportunistic in nature
- Target known vulnerabilities
- Use packaged attack tools
- Can be motivated by bragging rights, theft, activism, and exploration
- Market provided defenses are usually effective

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**Medium Level Threat**

**Structured Criminal**

- Can be experienced and skilled
- Access to financial resources
- Targeted in their attacks
- Posses objectives
- Use a range of attack tools
- Can be detected
- Exploit known vulnerabilities very quickly

**High Level Threat**

**Nation State**

- Draw upon skilled people
- Demonstrate sophisticated tactics
- Deep financial resources
- Rely on recon and planning
- Target specific technologies & data
- Develop customized attacked tools
- Can exploit unknown vulnerabilities
- Well defined goals & objectives Difficult to detect & remove
- Can use insider access
- Access to supply chains

Attacker capabilities vary greatly based on skill level and resources. High Level Threat Actors have the capability to employ or exploit all of the following:

| |
|---|
| Network traffic capture and analysis |
| Intercept and modify data inputs and outputs |
| Inject values or data into bidirectional traffic (Man-In-The-Middle attacks) |
| Physical layer (tampering, inputs, and add-ons) |
| Data & datalink layer (MAC address spoofing, root bridge, enable unauthorized DHCP server, VLAN trunking, etc.) |
| Network layer (injecting blackhole, rerouting, route manipulation, inject packets and malformed packets, source route IP packets, etc.) |
| Application layer (DNS cache poisoning, web browser attacks, digital certificate impersonation, TCP session hijacks, injects) |
| System layer (Operating System attacks, privilege escalation, remote control, computer resource management, etc.) |
| Behavioral (people) layer (man-to-machine interface and process) |
| Compromising and owning a connected device with administrative privileges |
| Denial of service attacks (Complete, Selective, etc.) |
| Weak authentication/authorization |
| Buffer Overflows |
| Integer Over/Underruns |
| Format String Flaws |
| Use of fuzzers and other logic flaws |
| Operating System and application flaws (evaluate common code weaknesses/programming errors and IT vulnerabilities) |
| Connected devices, servers, and databases (injection attacks) |
| Access to computer resource management (the actual board) |
| Consider the process for updates (supply chain, vendor patches)[14] |

Recent work by the FBI has classified threat groups into six major categories with references to methods of reaching their goal. Cyber Network Exploitation (CNE) is considered non-destructive while Cyber Network Attack (CNA) is destructive. CNE activity could be part of a long term effort to amass CNA capabilities with kinetic impacts, or generate new novel techniques, tactics, and procedures.

CNE may include expansion of threat actor understanding. CNE may also increase future CNA capability. For example, CNE in the form of exfiltration may be non-destructive in the present, but crucial to future destructive CNA capabilities or power projection.

CNA could be conducted as a means to an end in isolation, or as part of a larger, more complex effort to achieve broader goals beyond the effects of its own specific kinetic impacts. For example, CNA goals could extend to creating policy movement or fear among governments or populations.

[14] Scipio Group, LLC 2011

| Cyber Threat Group | Primary Motivation | What They Want | How They Get It |
|---|---|---|---|
| Foreign State | National Interest<br>Warfare | Information<br>Control | CNE<br>CNA |
| Terrorists | Ideology | Attention | CNA |
| Criminal | Money | Personally Identifiable Information<br>Ransom | CNE<br>CNA |
| Hacker | Personal Interest | Methods | CNE |
| Hacktivist | Cause | Support | CNA |
| Insider | Anger<br>Personal Enrichment | Revenge<br>Information | CNA<br>CNE[15] |

## Insiders

Insiders pose the greatest threat, especially if they are working with a Foreign State or other High Level Threat Actors, because of their detailed knowledge of system operations and security practices. In addition, they have legitimate physical and electronic access to key systems and the controls designed to protect them. Insider individuals can provide qualitative, technical or physical assistance to the team requirements of sophisticated adversaries or pose a unique unilateral threat detection challenge, if acting alone.

Individuals with the highest level of access pose the greatest threat. Furthermore, an individual with access to grid infrastructure could unwittingly or inadvertently introduce malware into a system through portable media or by falling victim to social engineering e-mails or other forms of communication.[16]

[15] FBI Presentation, NERC CIPC meeting, September 14, 2011, "US Electricity Sector Faces High Cyber Exploitation Threat, Low Cyber Attack Threat

[16] Department of Homeland Security Office of Intelligence and Analysis Note – Insider Threat to Utilities

# What a Coordinated Attack Looks Like

Depending on the capability and intent of an attacker, it can be very difficult to determine in advance that a coordinated cyber attack is occurring. A sophisticated attack, such as the Stuxnet worm, could have some or all of the following characteristics:

- First seen (new type of attack) or very rare
- Requires resources & skill to develop (thousands of hours of planning, development, and testing
- Usually highly structured threat actors
- Can be specific & directed
  - Technology (hardware) targeted
  - Application (software) targeted
  - Objective-based (e.g. impact BPS reliability)
- Can contain counters or responses to neutralize anticipated protective measures
- Difficult to attribute
- High reliability (usually tested before use)[17]

Cyber attack paths and methods (i.e. attack vectors) can also vary significantly based on the capability of the attacker, resource constraints, the intended target, and consequence. Attack vectors include:

- Via communication link between data and decision layers (e.g. Historian or real-time database server)
- Via connected WAN (e.g. Transmission SCADA Network, Corporate Network, etc.)
- Via connected device (e.g. Travel upstream from a data concentrator or application server)
- Via telecommunication network (e.g. POTS into dial-up accessible equipment)
- Via Wireless network (e.g. Blue tooth, 802.11x, etc.)
- Via remote connection (e.g. VPN for maintenance)
- Via portable media (e.g. USB stick)
- Physical access to the system[18]

A coordinated cyber attack may be timed to coincide with routine or abnormal bulk power system wide operational vulnerability periods in the daily or seasonal Demand-Response cycle. Cyber attacks may be combined with physical attacks which might be used to soften the system for a cyber knockout punch or to gain access to key facilities.

[17] Scipio Group, LLC 2011
[18] Ibid

## Prerequisites of an Attack

Three conditions must be present in order for an attacker (also known as a *threat agent*) to carry out an attack against a utility's system.

1. The defender must have **vulnerabilities** or weaknesses in their system.
2. The attacker must have sufficient **resources** available to exploit the defender's vulnerabilities. This is known as **capability.**
3. The attacker must believe they will **benefit** by performing the attack. The expectation of benefit drives **motivation**.

Condition one is completely dependent on the utility. Whether condition two is satisfied depends on both the utility and the attacker. The utility has some influence over which vulnerabilities exist and what level of resources will be required to exploit them. Different attackers have different capabilities.[19]

Condition three is associated with intent. Does the attacker have intent to disrupt or destroy the target or to exploit the target without disruptions?

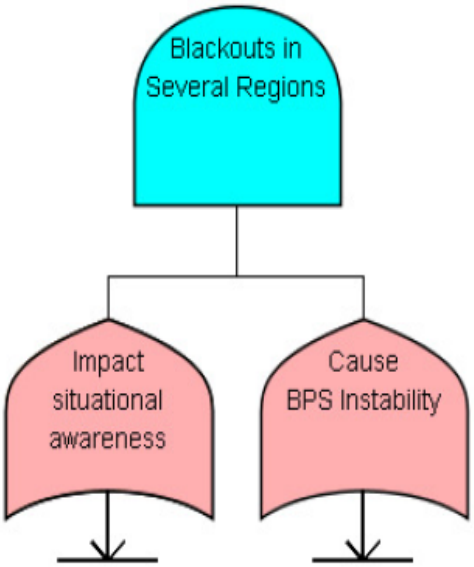
The task force chose to use an attack tree methodology to begin to build a picture of what a coordinated cyber attack could look like based on the attacker's intent to disrupt.

Attack Trees allow you to incorporate the capabilities of the attacker using specific profiles. The task force created attacker profiles that corresponded to low, medium, and high threat levels. In addition, resources (i.e. technical capability, noticeability, cost of attack, and attributability) associated with each leaf on the tree can be pruned or eliminated based on the profile of the attacker. In other words, an attacker with only medium technical ability would not be able to successfully navigate certain attack paths because steps (leaf nodes) required strong technical capabilities.

See Appendix A for an overview of attack trees.

[19] Ibid, page 3

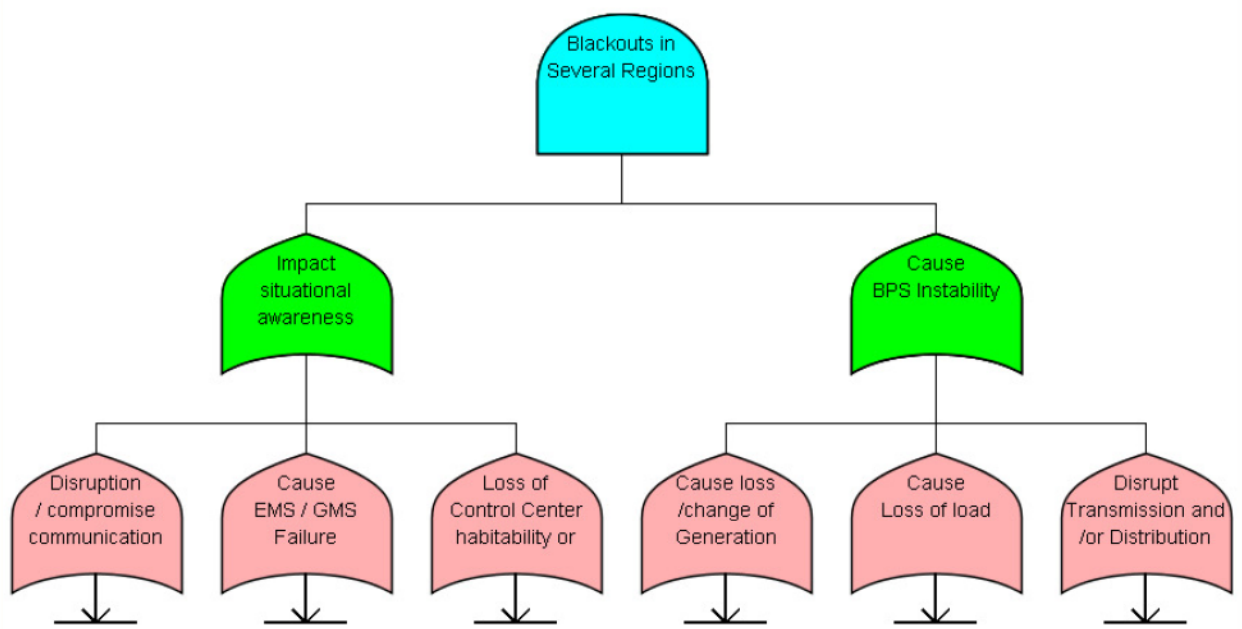
## Coordinated Cyber Attack Scenario and Assumptions:




1. BPS Instability - Transmission Operators report unexplained and persistent breaker operation that occurs across a wide geographic area (i.e. within state/province and neighboring state(s)/province(s).)
2. Impact Situational Awareness - Communications are disrupted, disabling Transmission Operator voice and data with half their neighbors, their Reliability Coordinator, and Balancing Authority.
3. BPS Instability - Loss of load and generation causes widespread BPS instability, and system collapse within state/province and neighboring state(s)/province(s). Portions of the grid remain operational.
4. Attack Result - Blackouts in several regions disrupt distribution supply to several million people.

The foundation assumption for a successful attack that results in a blackout in several regions is that two events need to occur: 1) situational awareness needs to have been compromised and 2) there must be a bulk power system event or instability.

Operational events regularly occur on the bulk power system without any noticeable impact to consumers. Operators are trained to take actions to mitigate the impact of such events. However, if the operator is unaware of wide area operating conditions, he/she can't implement mitigation actions and the result can be significant.




Expanding each of the two events:

Situational Awareness is impacted IF

- There is a Disruption / Compromise in Communications OR
- There is a failure of the Energy Management System or Generation Management System OR
- The Control Center is inaccessible or uninhabitable

The BPS Instability can occur IF

- There is a Loss/Change in Generation OR
- A Loss of Load OR
- A Disruption to Transmission or Distribution

Beyond the second layer of the Attack Tree are multiple layers that expand into literally millions of steps and paths (nodes) to accomplish the attacker's intent – blackouts in several regions. Work continues in the development of comprehensive attack trees and is the subject of a task force recommendation.

# Detection Capabilities

The ability to respond to an attack is contingent on the utility knowing that the attack could occur, is occurring or has occurred. The earlier the alert or warning, the better the chances that the operator, security teams and response tools can implement mitigation measures to minimize the impact of the attack on the bulk power system. However, operators can only go to the fight with the tools, awareness and training they have, so the effectiveness of mitigation depends critically on strategic preparations and investments necessarily taken over a long period of time at significant expense.

Operators must also be cognizant that the attacker may adapt to the implementation of defensive measures. But detection allows system defenders to manage the situation and make decisions to limit consequences or increase the effort required by the attacker throughout the process.

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Coordinated attacks require a significant amount of planning. Consequently, indicators of an attack could be identified far outside the operator's normal field of vision. Indicators could occur at a neighboring utility, within a balancing authority, in another region or interconnect or even in another country. Indicators may arise in areas totally outside the electricity sector, such as in the finance, IT or communications sectors.

Monitoring information sources for indicators of an attack is essential to maintaining situational awareness. Effective sector information sharing is key to obtaining useful indicators and warnings of a cyber attack and bulk power system risk.

An important nexus for collaborative information sharing on threats, vulnerabilities, prevention, and mitigation is the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). Operated by NERC, ES-ISAC is a center for sector-wide cybersecurity coordination, trust, and engagement. This vision is achieved through rapid sharing and analysis of information with the sector and its partners, providing sector-wide visibility and situational awareness. ES-ISAC staff are integrated with activities of the National Cybersecurity and Communications Center (NCCIC), a major government fusion cell operated by Department of Homeland Security (DHS).

In the event an attack, disables the ES-ISAC's ability to communicate with the electricity sector, a backup plan for distribution of critical information would need to be established. This is part of NERC's Crisis Plan, which is still under development. This is also true for inter-utility communication.

## Global Monitoring of Internet Activity

A number of security firms and IT service providers have sensors on sections of the Internet and for a fee will provide analysis of a company's network traffic offering alerts and indicators of potential attacks or reconnaissance.

In addition, some utilities have established partnerships with IT service providers to share advanced threat information. Some of these service providers also work with Department of Defense information, and can take advantage of other information sharing sources such as the DoD Cyber Crime Center's DIBNet. For example, Lockheed Martin announced a program called Palisade intended to provide utility and energy industry IT analysts with advanced threat detection and forensic tools, actionable intelligence to effectively identify and mitigate cyber security threats.[20]

## Federal Initiatives

Several federal agencies have initiatives in progress that are designed to assist the electricity sector in identifying indicators of a coordinated attack

- Department of Energy's Electricity Sector Network Monitoring (ESNM) program coordinated with Pacific Northwest National Laboratory (PNNL).
- The Department of Defense's program with Defense Industrial Base companies and their Internet Service Providers. DoD is providing attack signatures to help identify potential attackers. This program is expected to expand into the electricity sector.
- Department of Homeland Security - The Einstein system is intended to provide the government with early warnings about cyber attacks against federal networks, near real-time identification of malicious attacks, and automated disruptions of those strikes. The first version of Einstein dates back to 2003 and the second phase rolled out in 2008. It is now deployed at 15 out of 19 departments and agencies and in 2010, Einstein 2 sensors picked up 4.5 million "hits" or alerts based on pre-determined intrusion detection signatures. The Department of Homeland Security is currently working on Einstein 3, "which will provide DHS with the ability to automatically detect and disrupt malicious activity before harm is done to critical networks and systems."

While these types of programs for monitoring and identification of attacks have a solid foundation, there are limitations. Attacks can be crafted and implemented where there are no observable signatures in place.

## Peer Groups

NESCO, working with the National Electric Sector Cybersecurity Organization Resource (NESCOR), serves as a focal point bringing together utilities, federal agencies, regulators, researchers, and academics. This group, along with domestic and international experts, developers, and users help to focus cybersecurity research and development priorities, to identify and disseminate effective common practices, organize the collection, analysis and

[20] http://s1.securityweek.com/lockheed-martin-launches-cyber-security-solution-utility-and-energy-industry

dissemination of infrastructure vulnerabilities, and threats. NESCO works to identify and support efforts to enhance cybersecurity of the electric infrastructure. This project is being partially funded by the Department of Energy.

NESCO has established interest groups associated with intrusion detection, security architecture, threat assessment, and forensics.

The Electric Power Research Institute (EPRI) is coordinating several complimentary initiatives associated with industry and federal agencies. These efforts include 1) assessing combined cyber-physical attacks where the deliverables involve attack scenarios to feed into risk assessment models; 2) creating a scalable Advanced Metering Infrastructure (AMI) Incident response. The intent is a logical architecture for a scalable AMI intrusion detection system, a set of alarms and alerts to be standardized across vendors and guidelines for responding to AMI alarms.

A number of utilities have informal information sharing arrangements so sensitive information can be communicated to trusted sources.

## Alerts

There are multiple sources of alert information that the electric industry can reference to better identify early signs of a coordinated cyber attack. NERC's ES-ISAC and DHS's Industrial Control System – Computer Emergency Response Team (ICS-CERT) are import providers of relevant threat and vulnerability information related to Industrial Control Systems.

Many software and hardware manufacturers have e-mail or other alert distribution methods to notify customers of vulnerabilities and associated mitigation measures.

In addition to software and hardware vendors, utilities can look to activity in other countries as a potential precursor to a coordinated attack in North America.

Specialized Industrial Control Systems software along with off-the-shelf software is utilized in other critical infrastructure sectors that have close ties to the electricity sector. For example, PLCs are used in oil and nature gas and water facilities as well as power stations. Monitoring for malicious activity in other sectors can be an early indicator of a coordinated attack in the electricity sector.

See Appendix B for a list of sources and associated links.

## Precursors and Local Indicators

Experienced operators and support staff usually develop a 6th sense in regards to their job. Many times it is this "feeling" that something isn't right that heads off larger problems. While using this 6th sense is certainly valuable, establishing a baseline of expected values and then comparing those against real-time data points is an excellent method of comparison to determine if an unexpected situation exists. Following anomaly detection, trained staff can then follow-up with detailed analysis.

Appendix F contains a list that can be used as a starting point for indications of an unusual event. By developing real-time monitoring for these key metrics and comparing them to the base line, potential cyber attacks could be identified. However, these indicators do not take into consideration loss of data integrity where values are still within tolerances established by the entity. The industry eventually needs security state monitoring tools that trigger autonomic (i.e., quick device response) and/or dynamic (i.e., can evolve) corrective actions within the control system, while allowing operators to override them, if necessary[21] One potential proxy for this type of capability is the North American Synchro Phasor Initiative.

Synchrophasors are precise grid measurements now available from monitors called phasor measurement units (PMUs). PMU measurements are taken at high speed (typically 30 observations per second – compared to one every four seconds using conventional technology). Each measurement is time-stamped according to a common time reference. Time stamping allows synchrophasors from different utilities to be time-aligned (or "synchronized") and combined together providing a precise and comprehensive view of the entire interconnection. Synchrophasors enable a better indication of grid stress, and can be used to trigger corrective actions to maintain reliability (i.e. improving situational awareness)[22].

This type of technology provides indication of electrical network issues and could be used as an early warning indicator on a large scale. However, due to the speed of cascading events whether man-made or natural and their PMU indication, response to this type of detection may need to be automatic using predefined programmatic actions.

[21] Roadmap to Achieve Energy Delivery Systems Cybersecurity – September 2011, page 29

[22] North American Synchro Phasor Initiative - https://www.naspi.org/

# Deterrence / Defensive Capabilities

In broad terms, we can envision protecting the electricity sector with three separable, but complementary, layers of capability. The first layer is deterrence—capabilities and policies designed to convince an adversary not to launch a cyber attack. This is the job of the U.S., Canadian and Mexican governments. The second layer is defense—capabilities designed to reduce the effectiveness of the adversary's cyber attack. This layer is a primarily the responsibility of the electricity sector asset owners but does include governmental assistance. The third layer is reconstitution and robustness—capabilities designed to enable the bulk power system to continue functioning once it has suffered cyber damage and to enable the electricity sector to restore and rebuild its infrastructure after being damaged. Again, this is primarily the responsibility of the asset owners.

These layers achieve their objectives in different ways. Deterrence influences the adversary's intentions, convincing an adversary not to attack; defense works against the adversary's capabilities, defeating attacks that the adversary launches; reconstitution and robustness reduce the implications of successful attacks by the adversary. The layers complement each other by making up for limitations in other layers. If deterrence were known to be perfect, defense and reconstitution would be unnecessary; similarly, if defense were perfect, deterrence and reconstitution would be unnecessary. But, when none of the layers is perfect, each contributes to the sector's overall ability to protect itself.

Deterrence is frequently divided into two types—deterrence by punishment and deterrence by denial. When relying on a strategy of deterrence by punishment, the U.S., Canadian, and Mexican governments threaten to inflict costs (i.e. punishment) in retaliation for the bulk power system being attacked. The effectiveness of deterrence by punishment depends on both the size of the costs being threatened and the credibility of the threat. Credibility depends on both the ability to retaliate and the will to retaliate.

Deterrence by denial works by a different logic: in this approach, the electricity sector deploys capabilities to convince its adversary that the probability of its attack succeeding are low; this reduces the expected benefits of the attack and can therefore result in successful deterrence.[23]

The scope of this document will focus on the electricity sector's defensive and reconstitution/ robustness (i.e. survivability) capabilities.

A defense in depth security architecture has been, and continues to be, the foundation entities rely on to defend against cyber attacks. However, the engineering design of the electrical system also provides redundancy and resiliency that can help in minimizing or slowing down the impact or progress of an attack.

The NERC Critical Infrastructure Protection standards, CIP002 – CIP009 version 3, provide a minimum level of control and protection for what an entity believes are their critical assets and

[23] Deterrence of Cyber Attacks and the U.S. National Security, Charles L. Glaser

associated critical cyber assets. Specific electronic and physical controls and processes are mandated for all critical cyber assets and any cyber assets within the defined electronic and physical security perimeters.

CIP-002 – CIP-009 Version 4, which has not been approved by FERC, and CIP-002 – CIP-011 Version 5, which is still under development seek to clarify the breadth of assets that should be protected to provide adequate resiliency to the BPS in response to cyber and physical attack.

Other well known standards and documents that serve to help entities protect their key assets include;

**ANSI/ISA-99** is a complete security life-cycle program, with best practices for developing and deploying policy and technology solutions to address security issues in control systems. One aspect of the standard involves containing communication in control sub-systems to avoid having security issues in one area migrate to another area. ISA-99 introduces the concepts of "zones" and "conduits" as a way to segment and isolate the various sub-systems in a control system. A zone is defined as a grouping of logical or physical assets that share common security requirements based on factors such as criticality and consequence. Equipment in a zone has a security level capability. If that capability level is not equal to or higher than the requirement level, then extra security measures, such as implementing additional technology or policies, must be taken.

- **NIST SP800-53**, "Recommended Security Controls for Federal Information Systems," was developed primarily for Information Technology systems, but has been updated to address industrial control systems as well. It contains information for securing electronic systems from cyber intrusion. The standard is organized in sections or families of security categories.

- **NIST SP800-82**, "Guide to Industrial Control Systems (ICS) Security," is a guideline for securing industrial control systems. It is organized much the same as NIST SP800-53, but focuses on industrial control systems.

- **SANS 20 Critical Security Controls** - These Top 20 controls were agreed upon by a powerful consortium brought together by John Gilligan (previously CIO of the US Department of Energy and the U.S. Air Force) under the auspices of the Center for Strategic and International Studies. Members of the Consortium include NSA, US Cert, DoD JTF-GNO, the Department of Energy Nuclear Laboratories, Department of State, DoD Cyber Crime Center plus the top commercial forensics experts and pen testers that serve the banking and critical infrastructure communities.

In addition to the CIP standards, NERC alerts (e.g. Aurora, Stuxnet, and other vulnerabilities) provide guidance on additional controls to protect vulnerable or at risk equipment from attack.

Appendix H contains a list of some common defensive capabilities that have been or could be employed by electric utilities as part of their overall defense in-depth security architecture.

## Education / Training

As a coordinated attack has not been experienced to date, an operator faced with such an attack would have no real-life experience to draw on when responding to it. Further, little training presently exists to drill responses to these events, though certain organizations have recently begun to incorporate this material into their training programs.[24]

Training needs to include not only operators but field technicians as well. Focus should be on establishing a baseline to judge if "something looks or acts differently.".Then, the training needs to exercise the entities incident response plan which includes reporting.

Appendix C contains sample cyber attack scenarios that could be used to augment operational training.

More formal attacker/defender exercises such as those offered by Idaho National Laboratory (INL) are extremely beneficial in making entities aware of how attackers can respond.

NERC's Cyber Risk Preparedness Assessment (CRPA) is complementary to the program offered by INL. Using cyber threat and attack scenarios, this NERC-sponsored project conducts a qualitative, expert-based assessment of the preparedness of BPS entities to detect, respond to, and limit the potential damage caused by plausible cyber incidents.

These assessments focus on BPS entities' abilities to protect their cyber assets and improve preparedness regarding their cybersecurity posture. This is done by examining an entity's ability to defend its information systems, deter/deny attacks against those systems, detect attacks against its own or its peer systems, and respond to cyber attacks in a timely and efficient manner. The exercise also assesses the ability of BPS entities to isolate and limit attacks so that a system is able to withstand subsequent equipment losses and quickly be restored.

The objective is to leverage technically grounded cyber threat scenarios as the basis for assessing how BPS entities might detect, respond to, mitigate, and report cyber incidents, and to identify any capability gaps in their cybersecurity postures. In turn, this assessment will be used to identify steps required to improve overall BPS preparedness. [25]

## Incident Response Plans

Many entities have existing emergency plans that can complement or provide a foundation for cyber incident response planning. CIP008 requires the establishment and testing of a cyber incident response plan on an annual basis. Some of these plans address NERC or Regional Transmission Operator (RTO) requirements to ensure operational continuity, so backup or redundant assets could be leveraged to provide on-going capabilities from an incident.

[24] High Impact, Low-Frequency Event Risk to the North American Bulk Power System, June 2010

[25] NERC Cyber Risk Preparedness Assessment – Tabletop Exercise Report April 2010

For example:

- NERC Reliability Standard EOP-005 requires a restoration plan to recover from a partial or total shutdown of the bulk power system. This plan would identify assets that would be utilized for such a recovery. The incident response plan could be enhanced to include processes for addressing cyber incidents affecting restoration plan assets.

- NERC Reliability Standard EOP-008 establishes requirements to ensure continued reliable operation of the BPS in the event of the loss of a primary control center. A cyber incident response plan could be enhanced to assess this loss from a cyber perspective and provide information to complement the loss of control center plan.

The Severe Impact Resilience: Considerations and Recommendations report created by the Severe Impact Resiliency Task Force contains recommendations to address the loss of both primary and backup control centers.

NERC Reliability Standard COM-001 establishes requirements for adequate and reliable telecommunications and operating information. Entities would establish levels of redundancy or resiliency (or both) and provide an operational plan to recover from a loss.

Incident response plans could define crucial planning materials to allow for smooth response activities. This includes defining accurate and precise roles and responsibilities between IT, operations, and other support teams. Listing potential options for containing an incident, suggested measures for removing a threat such as malware or compromised accounts, suggested forensic methods, escalation methods, third party notification procedures, including vendors and law enforcement.

Defining roles and responsibilities will assist in the escalation and mobilization of response activities. Clear delineations between teams should be defined. Additionally, particular individuals should have clear authority to make decisions surrounding investigation and response activities as well as recovery activities.

At the industry level, NERC is in the process of finalizing their Crisis Response Plan. At the national level is the National Response Framework (NRF). The National Response Framework presents the guiding principles that enable all response partners to prepare for and provide a unified national response to disasters and emergencies – from the smallest incident to the largest catastrophe. This important document establishes a comprehensive, national, all-hazards approach to domestic incident response.

The framework defines the key principles, roles, and structures that organize the way we respond as a nation. It describes how communities, tribes, states, the federal government, private-sector, and nongovernmental partners apply these principles for a coordinated, effective national response. It also identifies special circumstances where the federal government exercises a larger role, including incidents where federal interests are involved and catastrophic incidents where a state would require significant support. The framework enables

first responders, decision-makers, and supporting entities to provide a unified national response.

Complimentary to the NRF is the DHS National Cyber Incident Response Plan (NCIRF). The National Cyber Incident Response Plan (NCIRP) was developed according to the principles outlined in the National Response Framework (NRF) and describes how the nation responds to significant cyber incidents.

ES-ISAC has developed a policy protected communications corridor which delineates special protections and handling for security discussions to encourage participation from the entities and insulate against excessive compliance concerns which might otherwise impede vital security dialogue. Policies like this set the stage for enhanced security by establishing venues for effective information sharing crucial to BPS risk management and response.

Rules of engagement for detecting, containing, and eradicating various incident scenarios will help guide personnel who are familiar with the incident response plan. This may include checklists for containment methods, procedures for forensic capture and evidence handling, and guidelines for disabling compromised accounts or reimaging server equipment.

One of the most important roles of any incident response plan involves communication. Communication could involve coordination:

- Between Reliability Coordinators
- Between Balancing Authorities
- Between Transmission Operators – minimize activities (i.e. maintenance outages) that would constrain an interface
- Between utilities
- With law enforcement
- With National Security Staff
- With regulators
- With ES-ISAC
- Between other sectors (oil and natural gas, nuclear, and dams)
- With and among technology vendor community participants

Creating an incident response plan is only one step towards being prepared for a security incident. It is invaluable to hold multi-team exercises or drills which develop familiarity with the incident response plans and defined roles and responsibilities during such events. Additionally, scenario-based drills which offer a plausible situation are a powerful tool to prepare staff on the potential confusion and hesitation which is inherent in an ongoing security incident. As part of any drill and in the case of an actual coordinated attack, it is imperative to communicate significant operational actions taken including their success or failure in mitigating or stopping the attack. This information is vital to partners so their responses are complimentary and not disruptive.

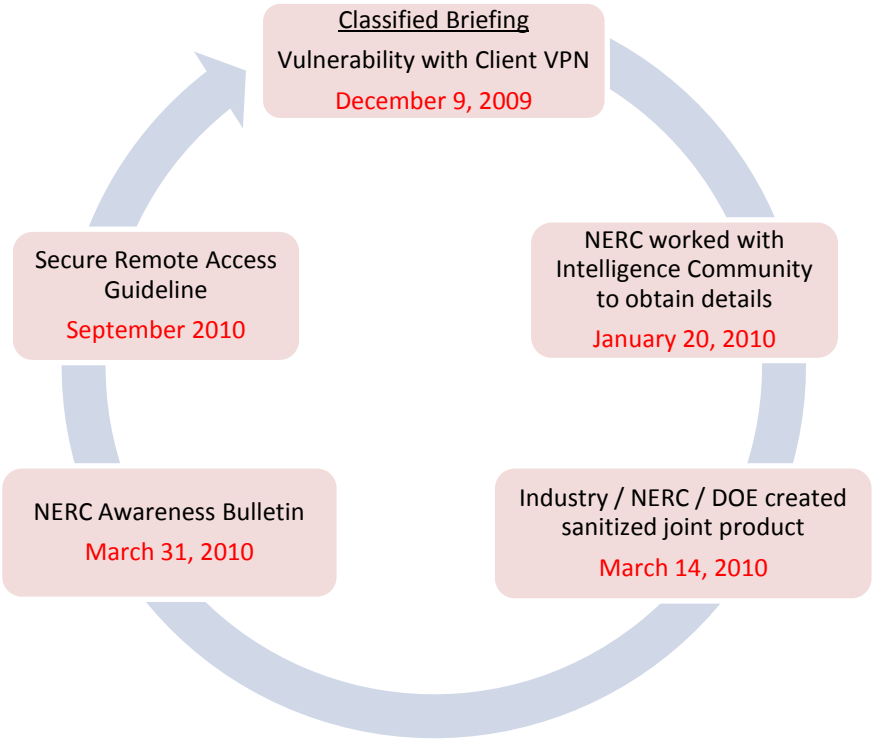
Auxiliary preparedness materials such as customer communication templates, emergency contact lists and preplanned secure/alternative communications methods (e.g. phone conference bridges; Government Emergency Telecommunications System (GETS) & Wireless Priority System (WPS) for priority access to telecommunications; satellite phone communications for the occurrence where landline and cellular facilities are not available) will enable a more rapid response operation. Creating customer communication templates may help customer support line representatives address calls from customers while other prepared documents may act as a template for communications staff to engage the local news media or government officials during or shortly after any impact from a security related incident. Emergency contact lists may list mobile contact information for management escalation and support staff such as operations staff, IT or cyber security team members. Additionally, it may list outside parties such as ES-ISAC, local, state or federal law enforcement, managed security service providers and system vendor technical support lines.

## Information Sharing

Information sharing is a critical component of any preparation as well as part of the actual response plan. Besides the formal, regulatory requirements for reporting unusual events outlined in the NERC CIP standards and the Department of Energy's OE-417, there exists an informal communication network between utilities and non-regulatory entities such as the North American Transmission Forum and the North American Generation Forum.

There have been successes between the industry, regulatory agencies and the intelligence community with taking classified intelligence, having industry experts assess sensitive information in a classified setting, remove or translate sensitive data and create an alert that can be distributed to a wider audience in the electricity industry.

A case study of success:




This exercise of having industry experts work with NERC and the Intelligence Community demonstrates the process can work. Future team efforts should strive to reduce the amount of time from briefing to awareness/alert.

Existing formal and informal sources of information include: NERC ES-ISAC, RCIS / CIPIS, North American Transmission Forum, North American Generation Forum; US-CERT, ICS-CERT, RRO and RTO "communities" – mail distribution groups, newsletters, etc. and Vendor "User Communities" such as EMS users' groups.

Energy Security Public-Private Partnership (ES3P) Joint Working Group has been formed under the Electricity Sub-Sector Coordinating Council (ESCC) and the Energy Sector Government Coordinating Council (ES-GCC). With co-Chairs from Department of Energy and NERC, as well as representation from Departments of Defense and Homeland Security, industry trade groups and interdependent sectors (such as Oil and Natural Gas, Water, Nuclear), ES3P offers a protected venue for sensitive critical infrastructure and mission assurance discussion.

Gaining awareness of a cyber attack before it occurs and stopping its effects is the best case scenario for information sharing. Sharing of information during the attack's reconnaissance phase or early delivery phase will help achieve this end.

Sharing of concise indicators of compromise (IOC) or attempted compromise will allow for quicker analysis of information and development of mitigations to prevent future incidents. These indicators of compromise may take the form of file MD5 hashes, IP addresses, targeted

phishing email header information, captured network traffic, or other detailed activity. Such IOCs will be detected by the industry and must be shared with its various partners such as the ES-ISAC to 'connect the dots'. The correlation of related indicators of compromise reported from independent industry members will create an industry view of attacks and will lead to informed preventative and detective measures which reduce overall risk to the BPS.

## Post-Event Analysis (Lessons Learned)

In order to properly prepare for the next security incident it is critical to capture lessons learned from prior incidents such as Stuxnet, Aurora, Night Dragon, Shady Rat and even events such as major hurricanes or tornados that resulted in disruptions. The lessons learned process should strive to identify how to prevent future attacks, prevent or limit disruption if they do occur, and create early visibility of such attacks through enhanced awareness and security monitoring.

Additionally, analysis of publicly disclosed attacks may provide a level of learning which may be incorporated into incident response plans, protective measures, resilience activity and preparedness. The FBI is working with the Pacific Northwest National Laboratory to evaluate and trend cases related to the electricity sector. The results of this analysis will be an important reference.

The NERC enterprise-wide event analysis program is based on the recognition that bulk power system events that occur, or have the potential to occur, have varying levels of significance. The manner in which registered entities, regional entities, and NERC evaluate and process these events is intended to reflect the significance of the event and/or specific system conditions germane to the reliability of the bulk power system and the circumstances involved.

The key ingredients of an effective post-event analysis program are to:

- Identify what transpired – sequence of events;
- Understand the causes of events;
- Understand the vulnerabilities that were exploited;
- Identify and ensure timely implementation of corrective actions;
- Develop and disseminate recommendations and valuable lessons learned to the industry to enhance operational performance and avoid repeat events;
- Develop the capability for integrating risk analysis into the event analysis process; and
- Feed forward key results to facilitate enhancements in and support of the various NERC programs and initiatives (e.g., performance metrics, standards, compliance monitoring and enforcement, training and education, etc.)[26]

While the full or partial loss of a single EMS or SCADA system may not result in the blackout depicted in the task force scenario, analysis of the causes of such a loss could be helpful in correcting conditions on the utility's EMS or SCADA system and possibly lead to the identification of useful lessons learned for the industry. However, in the case of a coordinated

[26] NERC Event Analysis Program

attack, impacting potentially multiple EMS and SCADA systems, it is imperative to capture the relevant actions and responses across each utility to create an accurate timeline similar to the 2003 Blackout.

Details of intrusions or compromises should also be incorporated into attack trees to continue to build on the catalogue of attack vectors and vulnerabilities.

## Procurement Language

A significant amount of work has been done by DOE, DHS, the national labs and electricity industry to create contractual language that entities can use when acquiring systems and equipment from vendors. EMS, SCADA and field devices often have a much longer operational lifetime then traditional IT business systems. By obligating vendors to provide documentation and evidence of security features, entities are better equipped to do adequate acceptance testing as well as properly design defensive measures when built-in security features need to be augmented.

See reference section for a link to the Cyber Security Procurement Language for Control Systems.

## Independent Testing of Systems and Equipment

Identifying and alerting the electricity sector of vulnerabilities so mitigation steps can be implemented is an important way to limit the number of successful attack vectors. Establishing partnerships between independent testing groups, hardware and software vendors and ICS-CERT and ES-ISAC encourages vulnerabilities to be identified and industry alerts issued in concert.

Unfortunately, the independent testing community is not always in synch with the hardware and software community when it comes to prioritizing the threats or even agreeing that there is a vulnerability. Recent examples involve the S4 Project Basecamp initiative where six ICS devices were evaluated, vulnerabilities identified, and exploit code made publically available. This partnership needs further development so the time between discovery of the vulnerability, disclosure of exploit code and release of patches or alerts is minimized as much as possible.

# Responses to Attack

## Background

Since the 2003 Blackout Report, the electricity sector has stressed the importance for system operators to maintain situational awareness of their respective systems. In the case of Reliability Coordinators (RC) there is also the need for these RC's to maintain situational awareness over a wide area (an area the extends beyond the operating zone of the RC). To achieve situational awareness the electricity sector has over the past decades developed increasingly sophisticated network applications, meters, and telemetry to paint the view of the system in ever more accurate terms. Often times these systems refresh for the operators every few minutes and in some case every few seconds.

Cyber Security experts often stress the importance of being able to protect the confidentiality and integrity of data and information, and the availability of systems/applications. While the confidentiality of our customers and member's data is very important a breach of this pillar of security does not necessarily jeopardize system reliability.

In spite of these applications having availability rates in the 99% range, these systems do occasionally fail. As such, every operating entity has back-up, call-out, and response plans to rapidly diagnose and address the rare application crashes.

Just as important as the system operations applications is the data and communication paths that feed these applications. These applications typically pull in thousands of data points from transmission sub-stations, lines, and generators every few seconds. In addition, entities are dependent on understanding and reacting to systems conditions with their neighbor's assets as well.

Cyber Security experts often stress the importance of being able to protect the confidentiality and integrity of data and information, and the availability of systems/applications. While the confidentiality of our customers and member's data is very important a breach of this pillar of security does not necessarily jeopardize system reliability.

In contrast the impacts associated with attacks on integrity (are outputs trusted?) and availability (are outputs meaningful and timely?) can have profound impacts on reliability.

The ideal response for these systems when under attack is to gracefully degrade in terms of capability without a material effect on operational reliability. This might mean, for example, that non-essential tools and functionality are shed, but control and communication with generating plants is maintained. If not already in place, this would require clear separation between core system reliability functionalities and business and market systems, external networks, and non-essential inputs. Networks should be designed such that these services can be quickly and easily disconnected from critical reliability functions at a moment's notice

without affecting operational reliability. This will essentially allow system operators to "fly with fewer controls."[27]

Identification of those core systems and functions that are essential to maintaining operational reliability would include:

- EMS (energy management system) – a control system with a suite of applications that provides decision support capability to monitoring and controlling the transmission system.
    - "Model" the heart of the EMS which replicates the portion of the grid the entity is responsible for operating,
    - State Estimation (SE) the way in which the model/EMS can estimate points not physically monitored (i.e. calculate the readings in the middle of a line with data from the readings on both ends of the line) and,
    - Security Analysis (SA) the more advanced applications of the EMS that conduct the "What If" contingency analysis so that operators can always position the system in a conservative/reliable state.
- GMS (generation management system) – the suite of applications that enable an entity to keep generation and other resources in balance with load.
- Ability to maintain communications control centers and field equipment (i.e. RTUs) to provide input to EMS/GMS.
- Core skilled workforce availability.

## Isolation and Survivability

Survivability involves focusing on protecting those systems and functions that are essential to maintaining reliable operations. Reliable operations will degrade, over time, resulting in the gradual reduction in services and functions until essential operations are no longer possible. The key is trying to maintain reliable operations in a reduced state for as long as possible. This resilience characteristic is known as graceful degradation of service.

A number of survivability and isolation tactics are outlined in Appendix G.

There are difficulties associated with isolation. Monitoring and situational awareness suffers as automated processes designed to inform operational staff are systemically severed. This includes both internal monitoring as well as connectivity with neighboring utilities. Bulk Power System control centers can pose risks to other BPS control systems via essential communication links. Internal data corruption, man in the middle scenarios, malicious code injections are all possible scenarios that must be considered when evaluating the operational impact that one control system may have on other externally connected control systems. Physically deploying

[27] High-Impact Low-Frequency Event Risk to the North American Bulk Power System page 37

staff to locations to determine status and relay information to operators in control centers would be challenging for an extended period of time.

Once integrity has been verified on end devices and communication paths, connectivity can be re-established. However, monitoring should be continued to ensure a re-occurrence of the disruption does not happen nor develop without operator recognition.

## Restoration

Restoration from a coordinated cyber attack could introduce conditions that are not normally encountered during restoration from hurricanes or other types of probabilistic events.

Restoration from a coordinated cyber attack could introduce conditions that are not normally encountered during restoration from hurricanes or other types of probabilistic events

During a cyber attack and the following aftermath, responders may be lulled into the false sense of security that there is only one wave of assault. As with a storm, once the storm passes, everyone pitches in to begin the restoration process with a clear and understood recovery plan. If the attack vector(s) and techniques/tools for the attack are not fully understood and mitigated, the attacker could launch subsequent attacks to disrupt recovery efforts or respond to mitigation efforts. These later attack waves may hold devastating impact potential if not understood and expected.

To ensure the attack vector(s) and methods have curtailed and can't be restarted, entities may need to restore application files and operating systems to a safe or trusted release. This can introduce problems or delay recovery due to any entity installed modifications. In addition, certain types of attacks can render hardware or other equipment inoperable. Consequently, new equipment may have to be acquired and installed. Manufacturer assistance may need to be obtained.

Restoration of situational awareness may have to be manually implemented with staff physically stationed at key locations until communication with monitoring equipment and associated telemetry is restored. Restoration may also involve repair or replacement of parts suffering physical damage from a cyber event. Some of these may require long lead times for replacement due to supply chain or skilled installation workforce availability issues.

Safety plays an even more important role during recovery than before. Because systems and equipment may behave unpredictably during restoration, extra caution should be communicated to staff to make them aware of this issue.

## Forensics

Determining the actual cause of an attack is difficult at best even with logs and other monitoring and intrusion detection capabilities found on business system networks. On the operational side of the Bulk Power System, equipment and software are not always capable of capturing information necessary to do a proper forensic analysis. Nonstandard protocols,

legacy architectures that can be several decades old, and irregular or extinct proprietary technologies can all combine to make the creation and operation of a cyber forensics program challenging.[28]

To aid asset owners and operators in this preparation, ICS–CERT has identified key elements for developing incident response capabilities necessary to collect data and perform follow-on actions to restore systems to normal operation.

One of the key elements is preserving forensic data. This includes methods for collecting, analyzing, and reporting these data, all of which are important components of any plan to avoid loss of essential information, provide for rapid operational restoration, and improve both near and long-term mitigation and security strategies. The following activities are recommended for preserving these important data in the event of a suspected incident.

- Keep detailed notes of what is observed, including dates/times, mitigation steps taken/ not taken, strange or unusual operational behavior, device logging enabled/disabled, and machine names for suspected compromised equipment. More information is generally better than less information.
- When possible, capture live system data (i.e., current network connections and open processes) prior to disconnecting a machine suspected of being compromised from the network.
- Capture forensic images of the system memory and hard drive prior to powering down the system.
- Avoid running any antivirus software "after the fact" as the antivirus scan changes critical file dates, which impedes discovery and analysis of suspected malicious files and timelines.
- Avoid making any changes to the operating system or hardware, including updates and patches, because they will overwrite important information about the suspected malware.[29]

The ICS-CERT provides onsite incident response, free of charge, to organizations that require immediate investigation and resolve in responding to a cyber attack. Upon notification of a cyber incident, ICS-CERT will perform a preliminary diagnosis to determine the extent of the compromise. At the customer's request, ICS-CERT can deploy a fly-away team to meet with the affected organization to review network topology, identify infected systems, image drives for analysis, and collect other data as needed to perform thorough follow-on analysis. ICS-CERT is able to provide mitigation strategies and assist asset owners/operators in restoring service and provide recommendations for improving overall network and control systems security.[30] ICS-CERT cannot, however, conduct criminal investigations.

[28] Recommended Practice: Creating Cyber Forensics Plans for Control Systems

[29] ICS-CERT Monthly Monitor July/August 2011

[30] DHS – Industrial Control System Computer Emergency Response Team (http://www.us-cert.gov/control_systems/ics-cert/more_information.html)

Entities that utilize outside services to assist with forensics or possible criminal prosecution should make sure the service provider or law enforcement agency is aware of all operational requirements and obligations. This could preclude on inhibit the collection of certain evidence (i.e. hardware and software) as part of the investigation.

See reference section for links to documents related to establishing a forensics program for control systems.

If prevention eventually fails, preparedness to detect the compromise before impact is realized is the next goal. The same data sources that lead to a sound post-incident forensics analysis will also provide the mechanisms to proactively detect and deter successful compromises.

These data sources include standard IT infrastructure logging such as firewall and intrusion detection systems. Secondary data sources that have proven to be invaluable during detection and forensics include Netflow data, Domain Name Resolution (DNS) logging, proxy logging, Email (SMTP) Logging, Remote Access (VPN) logging and full packet captures. It is recommended to extend the retention of these logs as long as feasible to maintain the historical forensics capability.

Once the above data sources are logged, they may be correlated together to give context of the source of the intrusion and the methods the adversary may be using. This correlation of key artifacts may be distilled into what is known as Indicators of Compromise (IOCs) which can allow for detection for follow-on attempts or sharing with the industry through trusted partners such as the ES-ISAC or ICS-CERT.

# Recommendations

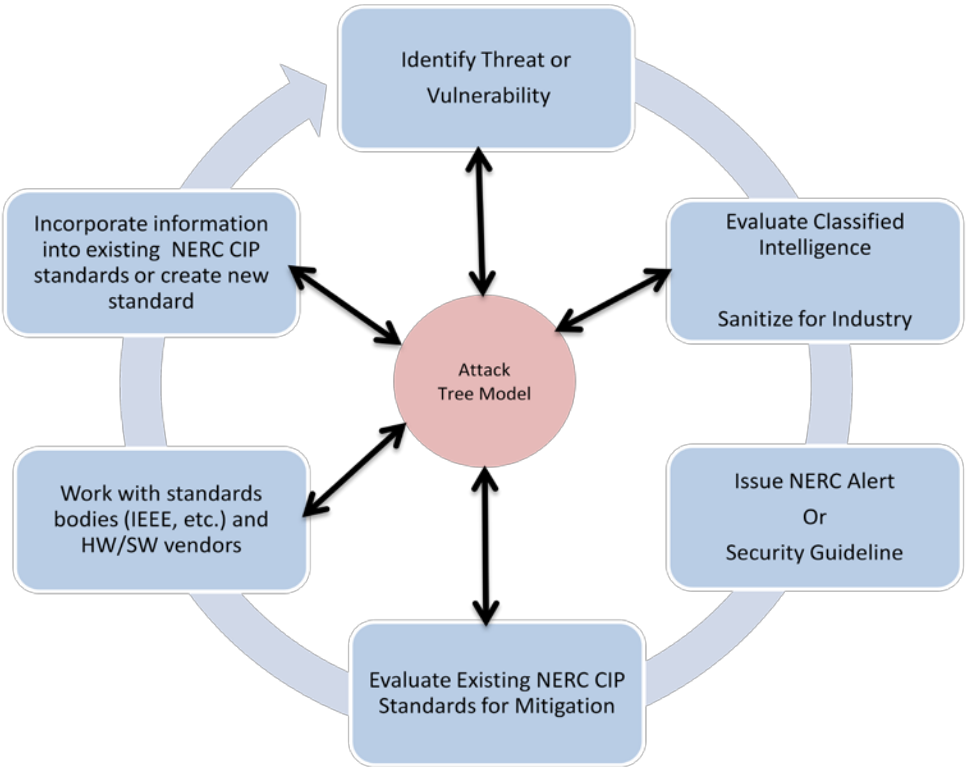
Following are the recommendations from the task force:

- **Continue to build on the Attack Trees -** A significant amount of work has gone into creating the attack tree framework, however recommendations from detailed analysis have not been completed. The top level root node of the attack tree is very specific to the task force scope, but lower level branches are applicable to many other scenarios such as attacks on generation, transmission/distribution or disrupting situational awareness.

  A separate working group under NERC's Critical Infrastructure Protection Committee (CIPC) should be established to further develop attack trees with the goal of populating the nodes, performing detailed analysis and providing recommendations to industry from this analysis.

  While these trees will never be finished, they do provide a solid structure to build on. For example, for each revision to the CIP standards the new requirements could be incorporated into the attack trees and analysis rerun to determine any positive or negative consequences of the propose changes. Prior to release of a NERC Alert, compare mitigation measure actions against the attack trees to determine if the recommendations provide the greatest likelihood of reducing the potential for compromise. At least annually evaluate the attack trees to incorporate new information.

  Because of the sensitive information captured and developed, the attack trees should be stored and managed as part of the NERC ES-ISAC documentation library, or in some cases, on classified systems.



- **Continue to develop security and operations staff skills to address increasingly sophisticated cyber threats -** Utilities should seek or develop methods to rapidly build the cybersecurity skills needed to enhance the security and reliability of the nation's electricity delivery system. Training programs should create development plans based on job roles and identified competencies to ensure that content and delivery addresses both knowledge and skill building. Hands-on development trainers are needed to provide practice opportunities and customize training. Aptitude assessments should be used to help tailor development efforts to meet the needs of individuals and teams and assess development effort effectiveness.

  Development efforts should include challenging cyber attack scenarios that are customized to the utility's technology environments and business operations. Development efforts should recognize gaps in the knowledge, skills, and abilities of cybersecurity personnel in detecting and responding to these threats.

  Entities should maintain an understanding of the current cyber threat as it applies to the electric sector; develop the skills to maintain situational awareness of that threat; strengthen the capability to match the external threat environment to the internal environment; and develop staff capability to use threat intelligence to best protect their organizations.

  Development programs should identify the skill components most in need by both security and operations job roles, and use assessment tools that will ensure that the programs produce the right skills and knowledge. These efforts should be applied beyond traditional information security environments and include the SCADA emergency management system, automated generation control, plant-level control systems, protection/safety systems, and field equipment.

- **Augment Operator Training with Cyber Attack Scenarios** – Several cyber attack scenario templates are included in Appendix C of this report. Existing Operator Training Simulators (OTS) or Dispatcher Training Simulators (DTS) should be leveraged to include cyber attacks. If these scenarios can be realistically captured and simulated, operators and technical staff could train under realistic conditions to recognize, react, respond, and defend against cyber-attacks before they ever encounter one in a production setting. The training should include collaboration and teamwork with physical and cyber security experts.

- **Conservative Operations -** Conservative Operations is an operational state resulting from the intentional actions taken in response to unknown, insecure, or potentially risky system conditions in order to move to a known, secure, and low-risk operating posture.

  A significant amount of work in preparing for conservative operations is documented in the Severe Impact Resilience: Considerations and Recommendations report created by the Sever Impact Resiliency Task Force. Entities should review this document for applicable best practices.

- **Continue to endorse existing NERC initiatives that help entities prepare for and respond to a cyber attack –** NERC has a number of initiatives that can help the industry with cyber attack identification, defense and response. Three examples are:
    - Cyber Readiness Preparedness Assessments (CRPA)
    - NERC Grid Security Exercise
    - ES-ISAC portal and collaboration

  The 2010 CRPA report identified eight observations and associated recommendations that came from 10 utility assessments. Each company should review the recommendations outlined in Appendix I for applicability to their program.

  Over 70 entities participated in the first NERC Grid Security Exercise. This provided an opportunity to test both internal and industry responses and communication capabilities.

  The CIPC should encourage entities to participate in all three efforts to fine tune their response plans. NERC should continue to fund and provide the necessary resources to expand the number entities that can participate in these programs.

- **Conduct exercise with Transmission Planners –** The bulk power system is inherently highly resilient to threats. Probabilistic planning criteria consider a wide range of potential contingencies and consider probabilistic failure (i.e. equipment failure, human error, and weather events) yet do not consider a structured, coordinated, and intelligent attacker. Additionally, the definition of a "single asset" under this criterion is often based on the probabilistic failure of a given system component (i.e. a single bus or circuit breaker or a single unit at a generating plant) and may not cover the loss of every component at multiple given physical locations (i.e. several entire substations or generating plants), as could be effected by a physical attack. Cyber attacks take this one step further by creating the possibility that an asset could be misused to affect assets connected to it. Consider the example of a large substation with multiple generating units connected to it. Though this capability has not been successfully demonstrated to date, an experienced cyber attacker could use relays and breakers within that substation to affect the operation of each of those plants.

  In order to accurately evaluate the system's resilience to structured attacks, the sector should work to incorporate these new perspectives and take a broader view of the system than is generally provided by traditional system planning and operating criteria. Entities within the sector have conducted such analyses with results that indicate the system would retain its integrity in the event of certain targeted attacks, however this practice should be considered more widely as planning methods evolve. Priority should be given to designing for survivability, such that the system could withstand and recover from a structured multi-

node attack. At a minimum, system planners and operators should be able to model the effects of such an attack and drill restoration measures.[31]

Working with Department of Energy national labs and a pilot group of electricity utilities, a transmission planning exercise should be coordinated by NERC to simulate a coordinated cyber attack that creates a cascading event and blackout. The event should attempt to identify the point at which current transmission planning criteria is exceeded and how to deal with dynamic mitigation. The results could provide insight into additional facilities/locations that might need protection beyond what is called for with the CIP and Transmission Planning (TPL) standards.

The exercise scenarios should be selected from a comprehensive hazard analysis method, such as using the attack tree work completed by the CATF or selecting another rigorous approach to identify and bound the attack scenarios.

- **Increase Awareness for Department of Energy Initiatives -** The Energy Sector Control Systems Working Group recently released the latest Roadmap to Achieve Energy Delivery System Cybersecurity. There are numerous initiatives that will help ensure protection of critical systems supporting the Bulk Power System going forward. In addition, the document serves as an excellent reference document that all entities can benefit from reading. Two initiatives that can have an immediate benefit are:

    - **Digital Bond / DOE – Bandolier initiative:** Digital Bond's Bandolier project helps asset owners and vendors identify and audit optimal security configuration for industrial control system (ICS) servers and workstations. Digital Bond partners with leading ICS vendors to identify the optimal security configuration that still allows the vendor's product to operate properly. This requires access to the vendor's security experts, lead engineers and a test lab. Digital Bond then creates Bandolier Security Audit Files that work with the compliance plugin in the Nessus vulnerability scanner. Bandolier Security Audit Files are available for over twenty control system components, with more on the way.

      http://www.digitalbond.com/tools/bandolier/

    - **Digital Bond / DOE – Portaledge Project:** Portaledge is a Digital Bond research project that **aggregates** security events from a variety of data sources on the control system network and then correlates the security events to identify cyber attacks. Portaledge leverages the aggregation and correlation capability of OSIsoft's PI server, and its large installed base in the energy sector to provide this cyber detection capability in a system many industrial control system (ICS) owner / operators already have deployed.

      http://www.digitalbond.com/tools/portaledge/

[31] High-Impact Low Frequency Event Risk to the North American Bulk Power System page 36

- **Continue to Extend Public / Private Partnership** – More and more US and Canadian electricity sector staff have been granted clearances to see classified information. As the US and Canadian Intelligence Communities working with NERC discovers new vulnerabilities and threats, this information should be disseminated to the electricity sector as quickly as possible. The electricity industry must ensure an appropriate mix of operational, security, technical and managerial staff is cleared and available to evaluate, respond and make timely decisions to slow or stop an attack.

  Effective information sharing can be enabled in multiple ways including having clearances passed to local FBI offices and Fusion Centers so expedited secure communications can be accomplished with a wider portion of the industry. It is important to ensure the inclusion of the appropriate representation from the law enforcement community, as the traditional separation of tactical field operations and national security operations do not necessarily facilitate the proper sharing of information. In Canada, jurisdiction for Canadian electricity utilities varies from province to province. The provincial law enforcement agencies have a reporting relationship with the Royal Canadian Mounted Police (RCMP).

  In addition, NERC and federal agencies should continue to involve sector experts to help translate classified information (e.g. preparing useful tear-line material) into alerts that can be issued to the industry. This re-enforces the life cycle approach to addressing vulnerabilities.

  The ES-ISAC offers an increasingly robust portal environment to organize electronic collaboration and this development effort should be strongly supported. ES-ISAC is establishing protective procedures to provide insulation from compliance concerns which might otherwise limit the willingness to share vital security information before, during or after a contingency. In the event standard information sharing protocols are unavailable during an attack (e.g. between utilities, ES-ISAC, etc), alternative methods need to be defined.

  In parallel, the electricity sector needs to improve its sharing of information with federal agencies. Historically, there has been and continues to be a reluctance to do this because of the uncertainty about where the information could end up or that the disclosure could result in a perceived compliance violation.

# Outreach

Outreach is an important part of asserting deliberate intent of the sector to cause transformative change. If the goal is to fortify sector security against a coordinated cyber attack, outreach activity will raise awareness of the issue and equip sector participants with the motivation and knowledge to enhance capabilities.

| SUCCESS ELEMENTS | WHAT IT MEANS… | ACTIONS |
|---|---|---|
| Skilled Workforce | Long-term workforce development providing scale and capacity of vital skill sets and qualifications in security related professions and trades. | • Work in conjunction with National Board of Information Security Examiners (NBISE) initiatives to enhance workforce development in both IT and OT security<br>• Encourage continued participation in Advanced Industrial Control System Red/Blue Team Training offered by Idaho National Labs. |
| Leadership Engagement | Leaders driven by passionate focus on security viewed as a strategic competitive advantage at entity, sector, national and international levels. | • Provide periodic updates to the NERC CIPC, ESCC on status of Cyber Attack Task Force and any follow-up working group activities. |
| Vertical Communications | Effective two-way communications between authoritative information sources and entities. | • Report events to the ES-ISAC, the FBI and applicable Canadian law enforcement agencies to better identify trends<br>• Engage FBI, DHS and DOE resources to provide input to attack trees<br>• Coordinate with DOE, the national labs and DHS on other cyber attack programs, both at the classified and unclassified level.<br>• Communicate with FERC and Congressional staff (through NERC and Industry Trade Associations) to educate regulators about the work being done by the electricity sector. |
| Horizontal Communications | Communications between proactively engaged entities sharing issues, opportunities, perceived gaps and best practices. | • Encourage entity sharing of information with ES-ISAC related to systems events.<br>• Participate in initiatives such as those offered by NESCO |

| | | |
|---|---|---|
| Communications Content | Comprehensive with holistic integration of threat, vulnerability, planning, operational, mitigation, and process issues. Standard lexicon, formats and redundant, interoperable, classification controlled pathways are employed. | • CIPC members and other Subject Matter Experts should continue to work closely with the NERC ES-ISAC on timely and relevant alerts |
| Advanced Technology Application | Provision and use of cost effective, sustainable technologies and services. Vendors and supply chain participants are energized and innovative --committed to trusted secure supply chains and optimal new product development, informed by sector expertise, emerging threats and real vulnerability gaps. | • Work with the Energy Sector Control Systems Working Group on enhancements and updates to the Roadmap to Achieve Energy Delivery Systems Cybersecurity |

# References

| Name | Link |
|---|---|
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| Critical Infrastructure Strategic Roadmap | http://www.nerc.com/docs/escc/ESCC_Strat_Roadmap_V5_20_Oct2010_clean.pdf |
| NERC Technical Committees' Report – *Critical Infrastructure Strategic Initiatives Coordinated Action Plan* | http://www.nerc.com/docs/ciscap/Critical_Infrastructure_Strategic_Initiatives_Coordinated_Action_Plan_102510.pdf |
| NERC Scope: Cyber Attack Task Force | http://www.nerc.com/filez/catf.html |
| Roadmap to Achieve Energy Delivery Systems Cybersecurity – September 2011 | http://www.controlsystemsroadmap.net/pdfs/roadmap.pdf |
| NERC CIP Standards | http://www.nerc.com/page.php?cid=2\|20 |
| Insider Threats to Utilities | DHS Office of Intelligence and Analysis – July 19, 2011 Note |
| US Electricity Sector Faces High Cyber Exploitation Threat, Low Cyber Attack Threat | FBI presentation, http://www.nerc.com/docs/cip/CIPC%20Presentations%20September%202011.zip |
| NERC Cyber Risk Preparedness Assessment – Tabletop Exercise Report April 2010 | http://www.esisac.com/Public%20Library/Reports/CRPA%202010%20Report.pdf |
| DHS Report – Preventing and Defending Against Cyber Attacks – June 2011 | http://www.dhs.gov/xlibrary/assets/preventing-and-defending-against-cyber-attacks.pdf |
| DHS Recommended Practice: Creating Cyber Forensics Plans for Control Systems | http://www.us-cert.gov/control_systems/pdf/Forensics_RP.pdf |
| DHS Cyber Threat Source Descriptions | http://www.us-cert.gov/control_systems/csthreats.html |
| Recommended Practice: Creating Cyber Forensics Plans for Control Systems | http://www.inl.gov/technicalpublications/Documents/4113665.pdf |
| DHS - | http://www.us-cert.gov/control_systems/pdf/Incident_Handling_Brochure_Nov_2010.pdf |

| | |
|---|---|
| The Use of Attack Trees in Assessing Vulnerabilities in SCADA Systems | http://www.tofinosecurity.com/professional/use-attack-trees-assessing-vulnerabilities-scada-system |
| Developing an Industrial Control Systems Cybersecurity Incident Response Capability, 2009 | http://www.usert.gov/control_systems/practices/documents/final-RP_ics_cybersecurity_incident_response_100609.pdf. |
| NIST SP800-86 Guide to Integrating Forensic Techniques into Incident Response | http://csrc.nist.gov/publications/nistpubs/800-86/SP800-86.pdf |
| NIST 800-61, "Computer Security Incident Handling Guide | http://csrc.nist.gov/publications/nistpubs/800-61-rev1/SP800-61rev1.pdf |
| National Electric Sector Cyber Security Organization | http://www.energysec.org/nesco |
| Improving Industrial Control Systems Cybersecurity with Defense-in-Depth Strategies | http://www.us-cert.gov/controlsystems/practices/RecommendedPractices.html |
| ERO Event Analysis Process | http://www.nerc.com/filez/eawg.html |
| NSA Manageable Network Plan | http://www.nsa.gov/ia/_files/vtechrep/ManageableNetworkPlan.pdf |
| DHS Procurement Language for Control Systems | http://www.us-cert.gov/control_systems/pdf/FINAL-Procurement_Language_Rev4_100809.pdf |
| National Response Framework | http://www.fema.gov/pdf/emergency/nrf/nrf-core.pdf |
| SANS 20 Critical Security Controls | http://www.sans.org/critical-security-controls/ |

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# Appendix A: Introduction to Attack Trees

Threat trees are the first component of an attack tree. Threat (or fault) trees are used to determine whether the conditions necessary for a threat to be realized exist and are un-mitigated. A threat tree consists of threat outcomes:

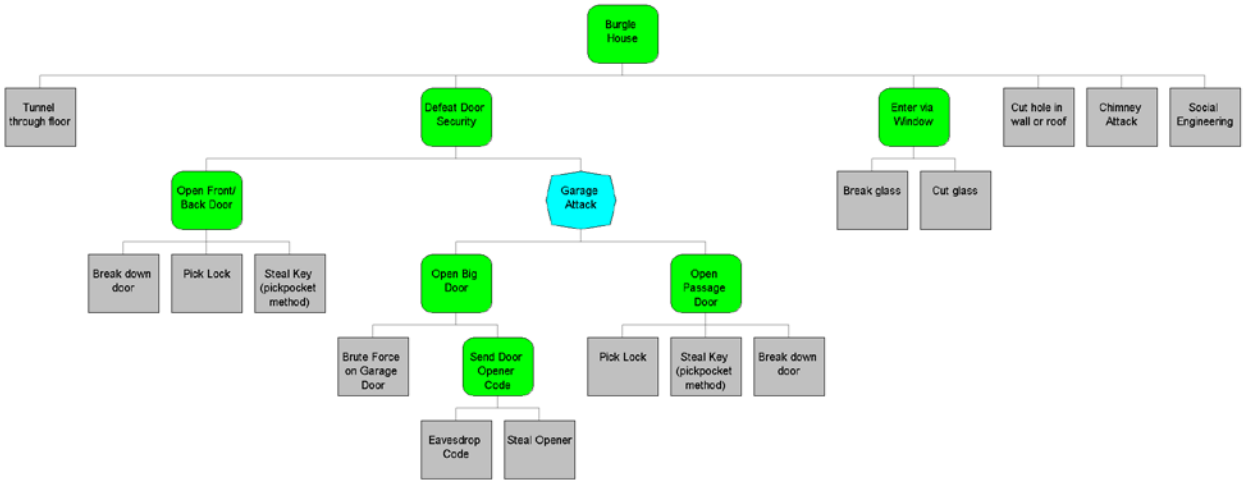
(e.g., long-term service disruption to a large area), in which preexisting conditions that must be true for an adversary to realize the threat (e.g., a circuit breaker is accessible through Internet connectivity). Any condition can, in turn, have one or more preconditions. Two or more conditions at the same level and sharing the same parent node can be combined, resulting in an "and" relationship; otherwise, an implicit "or" condition exists. Determining whether one or more vulnerabilities are associated with a threat is simply a matter of starting at a leaf condition (a node in the threat tree with no child nodes) and following it up to the root threat. If a path is unbroken by a mitigated node or a broken "and" condition exist, a vulnerability exists.

This information combined with intelligence about adversaries can be used to create an attack tree. Certain vulnerabilities are more likely to be exploited based on the attacker's capabilities (resources, geographic location, and industry experience.), while others will be virtually impossible to exploit.

The impact of a threat can be calculated quickly from the attack tree, which can, in turn, be used to justify or inform expenditures or resource allocation planning on mitigation strategies. Impact can be calculated by adding the financial and operational impact of the root of the tree to any impact created as attackers work their way up the tree. Some of the intermediate nodes in the tree may have an adverse impact, even if the attacker doesn't have the capabilities to extend further up the tree.

Once an impact is calculated, it is possible to calculate the value of investing in mitigation strategies. Based on the impact and the likelihood of occurrence, it is possible to determine whether countermeasures should be used for that vulnerability – or whether the vulnerability is so difficult to exploit (or has so little impact) that countermeasures are unnecessary.[32]

[32] American Electric and Power Attack Tree Methodology


Burgle House
Tunnel through floor
Defeat Door Security
Enter via Window
Cut hole in wall or roof
Chimney Attack
Social Engineering
Open Front/ Back Door
Garage Attack
Break glass
Cut glass
Break down door
Pick Lock
Steal Key (pickpocket method)
Open Big Door
Open Passage Door
Brute Force on Garage Door
Send Door Opener Code
Pick Lock
Steal Key (pickpocket method)
Break down door
Eavesdrop Code
Steal Opener

# Appendix B: Resources

**United States**

- NERC Electricity Sector – Information Sharing and Analysis Center (ES-ISAC)
  http://www.esisac.net/SitePages/Home.aspx
- Department of Homeland Security
  - United States Computer Emergency Response Team (US-CERT)
    http://www.uscert.gov/
  - Industrial Control System – Computer Emergency Response Team (ICS-CERT)
    http://www.uscert.gov/control_systems/ics-cert/
  - Control Systems Security Program
    http://www.us-cert.gov/control_systems/cstraining.html#workshop
- International Computer Emergency Response Teams
  http://www.internationalcybercenter.org/certicc/certworld
- National Council of Information Sharing and Analysis Centers (ISACs)
  http://www.isaccouncil.org/index.php?option=com_content&view=article&id=87&Itemid=194
- Federal Bureau of Investigation
  http://www.fbi.gov
  http://www.infragard.net/
- Domestic Security Alliance Council

  http://www.dsac.gov/Pages/index.aspx

**United Kingdom**

- CPNI – Center for the Protection of National Infrastructure

http://www.cpni.gov.uk/

- SOCA – Serious Organized Crime Agency

http://www.soca.gov.uk/

**Canada**

- RCMP – Royal Canadian Mounted Police

http://www.rcmp-grc.gc.ca/index-eng.htm

- CCIRC – Canadian Cyber Incident Response Center

http://www.publicsafety.gc.ca/prg/em/ccirc/index-eng.aspx

**New Zealand**

- CCIP – Center for Critical Infrastructure Protection

http://www.ncsc.govt.nz/

**Australia**

- AFP – Australian Federal Police

http://www.afp.gov.au/

- CERT Australia – Computer Emergency Response Team

http://www.auscert.org.au/

**Vendor Alerts**

- ABB – www.abb.com
- Alstom Grid – www.alstom.com/grid/products-and-services/electrical-network-systems/
- Open Systems International – www.osii.com
- Schweitzer Engineering Laboratories – www.selinc.com
- Siemens – www.seimens.com

# Appendix C: Cyber Event Scenarios for System Operators

## Overview

The following scenarios are presented in order from more plausible to less plausible. Plausibility is based on the perceived ease with which a malicious individual could accomplish the task. The scenarios are centered on operator trainee actions as opposed to support personnel actions.

We identified at least four major categories of events, and chose scenarios from among these:

- Social engineering
- Denial of service
- Spurious device operation
- Realistic data injection

Almost all of the symptoms described in these scenarios could, and in overwhelming likelihood would arise from any number of problems *other* than a cyber attack. These other likelihoods should be considered before a cyber attack is assumed.

## Social Engineering – false request or information to operator

### Description

In this scenario, a malicious individual contacts an operator and makes a request for action or information, or supplies false information. This individual could be a disgruntled current or former employee. They could represent themselves as field personnel, and RTO employee, or any number of legitimate individuals.

### Implementation

During a training exercise a phone call could be made to the trainee, with the individual asking for an action or supplying false information.

Example: “Hello, this is John Doe at Metropolis substation. We’ve got a big problem here and need you to open the 1A breaker ASAP.”

### Recognition

Awareness and a questioning attitude are probably the best tools for recognizing this scenario.

- Is this an unusual request?
- Is this a familiar identifiable person?
- Does this person possess particular knowledge about the situation when asked?
- Is this one of many unusual or suspicious requests?

### Response

If a suspicious request is received, obviously the trainee would not act on it. They should:

- Try to gain more information from the caller if possible
- Consider the appropriateness of the request
- Attempt to identify the individual
- Verify the request with another entity (cross check)
- If the situation remains suspicious, report the incident to their appropriate supervision and support personnel

## Denial of Service – EMS network

Description

EMS computer network becomes fully or partially unavailable, or network performance declines. Scenario proposes that malicious activity has adversely affected EMS network.

Implementation

This is most easily staged in a training simulator environment, or even on a separate training network. Any number of methods could produce the appearance of network loss or overload.

- Disconnect operator workstations from network at a location unseen by the trainees
- Remotely alter workstation or training network settings such that slow network response is observed
- Administratively terminating workstation sessions may give the appearance of network loss

Recognition

- EMS system may seem completely unresponsive
- User interface may spuriously disconnect then reconnect
- May experience timeouts when performing actions
- May experience multiple telemetry failures
- Other evidence of unauthorized system access exists or was suspected

Response

- Consider the extent of symptoms – one or two workstations, entire system, other corporate non-EMS systems
- Contact I.T. support staff
- Consider a move to offsite disaster facility while support staff secures primary EMS facility

## Denial of Service – EMS applications halted

Description

Certain applications on the EMS have been maliciously halted. Therefore, the EMS system is not providing proper updates. Could be coupled with control compromise or physical sabotage in the field – the trainee of course would not be aware of it.

Implementation

Most likely requires a training simulator environment. In that environment, key applications such as the alarm system or data scanning applications are quietly halted. This might be accompanied by simulated manipulation of the actual power system while these programs are unavailable.

If the situation should go unnoticed, a simulated call from field personnel asking about a particular situation might call attention to the lack of updates.

Recognition

- EMS system does not appear to be updating
- May be lack of EMS alarms for an extended period
- Phone call from other personnel reporting changes not reflected in EMS
- When EMS system is restored, a large number of changes might be indicated
- Other evidence of unauthorized system access exists or was suspected

Response

- Cross check indicated data with other personnel or systems
- Notify support staff

## Spurious Device Operations

Description

Multiple, un-commanded, unexpected device operations indicated in EMS system. Scenario could be based on:

- Indication-only compromise (devices aren't actually changing)
- Control compromise (devices are actually being manipulated)

Implementation

Most likely requires a training simulator environment. In that environment, event scenarios could be devised to:

- Simulate compromised telemetry, such that false indications and alarms are present
- Alter the power system simulation, such that power system devices actually operate (simulate a control compromise)

Recognition

- Unexpected state changes
- Could be multiple changes at unrelated locations
- May be conflicting indications (e.g. breakers open but flow present)
- Other evidence of unauthorized system access exists or was suspected
- State estimator may indicate that data is conflicting

Response

- If possible verify indications (cross-check)
- Verify with field personnel
- Call support staff

## Realistic Data Injection

### Description

Convincing injection of false data into EMS or associated systems, for the purpose of changing operator behavior. This is much more subtle than strict denial of service and requires much greater knowledge of the system. Examples of changed operator behavior:

- Convince them to shed load
- Convince them to allow equipment overload/damage
- Cause then to ignore changes taking place on the power system

### Implementation

Most likely requires a training simulator environment. In that environment, event scenarios could be devised to bias operator indications so that they do not match the true power system simulation. The power system simulation may be trending toward an adverse state, and this would be unknown to the trainee.

### Recognition

The fact that this attack is very difficult to accomplish completely can help in recognition. It is possible the offender would make mistakes such that some indications would not look normal.

- Lack of correlation between measurements
- Indications defy known system conditions
- Some indications appear abnormal (offender failed to accomplish convincing injection)
- State estimator may flag anomalies where they didn't previously exist
- Other evidence of unauthorized system access exists or was suspected

### Response

- If possible verify indications (cross-check)
- Verify with field personnel
- Call support staff

# Appendix D: Acronyms

| | |
|---|---|
| AGC | Automatic Generator Control |
| BA | Balancing Authority |
| CA | Critical Asset |
| CCA | Critical Cyber Asset |
| CIPAC | Critical Infrastructure Partnership Advisory Council |
| CIPIS | Critical Infrastructure Protection Information System |
| CIPC | Critical Infrastructure Protection Committee |
| DCS | Distributed Control System |
| DHCP | Dynamic Host Configuration Protocol |
| DNS | Domain Name Services |
| DOS | Denial of Service |
| DDOS | Distributed Denial of Service |
| EGSEC | Energy Grid Security Executive Council |
| EMS | Energy Management System |
| ES3P | Electricity Sector Public Private Partnership |
| ES-ISAC | Electricity Sector Information Sharing and Analysis Center |
| ESP | Electronic Security Perimeter |
| ESCC | Electricty Sub-sector Coordinating Council |
| ICCP | Inter- Control Center Communication Protocol |

| | |
|---|---|
| ICS | Industrial Control System |
| IDS | Intrusion Detection System |
| IP | Internet Protocol (see TCP/IP) |
| IPS | Intrusion Prevention System |
| MAC | Media Access Control |
| MD5 | Message Digest 5 |
| OS | Operating System |
| PLC | Programmable Logic Controller |
| POTS | Plain Old Telephone Service |
| RC | Reliability Coordinator |
| RCIS | Reliability Coordinator Information System |
| RRO | Regional Reliability Organization (SERC, NPCC, WECC, etc.) |
| RTO | Regional Transmission Operator |
| RTU | Remote Terminal Unit |
| SCADA | Supervisory Control and Data Acquisition |
| TCP/IP | Transmission Control Protocol / Internet Protocol |
| TPL | Transmission Planning |
| USB | Universal Serial Bus |
| VLAN | Virtual Local Area Network |
| VPN | Virtual Private Network |

# Appendix E: Potential Responses to an Attack

Because attacks can come in different forms and attackers have different capabilities and motivations, it is impossible to prepare for them all. Each utility should create and execute a triage plan that will protect the most critical systems associated with real-time operations and situational awareness.

Listed below are a list of actions to consider based on the characteristics of the attack. These actions are broken up into the following categories:

- Voice and Data Communications
- Network Defenses (Internal and External)
- Operations (EMS/SCADA, Transmission, Generation)
- Information Sharing
- Forensics
- Personnel

**Response Actions to Consider**

- **Voice and Data Communications**
  - Determine impact to landline, VOIP and cellular communications as it relates to the Bulk Power System
  - Determine impact to ICCP, VOIP and other messaging data communications as it relates to Bulk Power System
  - Initiate satellite communication systems
    - Intra-communication to key power plants, etc.
    - Extra-communication to neighboring utilities, RC, RTOs, etc.

- **Network Defenses (Internal and External)**
  - Review password settings on key operational equipment and systems and knowledge of that information, and determine if possible modifications should be considered.
  - Check integrity of facility support systems (HVAC, water supply, physical access controls)
  - Review IDS/IPS and firewall settings to verify allowed access is still valid and required for current operating conditions.
  - Consider disconnecting external connections to business partners (e.g. VPNs or other point to point connections)
  - Remove all non-essential in-bound network access to control systems and related ESPs (remove support staff remote access)

- Remove all dial-up and remote command and control access links
- Implement IDS, IPS systems or FW rules that shun or block access attempts from source (if source info is provided)
- Review external network activity logs (especially for ESPs)
- Validate that only authorized access attempts are indicated in log files
- Tighten down host-based controls
- Temporarily change logging thresholds on key systems to capture more data for analysis

- **Operations (EMS/SCADA, Transmission, Generation)**
  - Review password settings on key operational equipment and systems and knowledge of that information, and determine if possible modifications should be considered.
  - Initiate emergency operations plans dealing w/ loss of communications and loss of control center functionality
  - Change control systems passwords for all systems deemed CCAs. Include non-CCAs as appropriate.
  - Remove contractor access to control systems and require escort access for all non-employees
  - Terminate control systems (EMS/SCADA) communication to the point that compromise is contained or rendered ineffective
  - Ensure EMS and State Estimation functions are operating properly. Validate and much as possible critical assumptions and values in database(s)
  - On a pre-determined schedule - Coordinate with Neighboring TOP/RCs on data validation points. Validation points are points where both entities have either independent monitoring or state estimated points from their own respective models. Both entities should be able to confer that based upon a predetermined set of validation points their respective state estimation and security analysis applications are both arriving at similar (not necessarily equal) values.
  - Disable EMS/SCADA control in a manner that preserves system stability while maximizing situational awareness for operators. (e.g. disable operator-initiated controls, followed by AGC if absolutely needed)
  - If disabling control fails to isolate the conditions, fully diable EMS/SCADA and operate power grid in manual mode by disabling all RTU communications. Disabling EMS/SCADA will hopefully preserve the state of the system forensic analysis.
  - Recover offsite backup tapes or “gold” copies of operating systems, configuration file, or applications for recovery purposes.

- Failover to backup control system(s)
- Contact your key hardware and application (including EMS/SCADA/Relays) vendors.
- Establish trigger points of distrust – i.e., if values diverge from one scan to the next by X% - attempt to validate value from other associated readings (i.e. are signals of large generation losses confirmed by changes in tie values). With such triggers, Operators should only take actions that can be validated at multiple ends via telecommunications.
- Work with vendor to develop/implement a solution (i.e. update firmware/software, replace compromised equipment with updated firmware, passwords, etc.)
- If attack corrupts primary and backup control center (BUCC) systems run off-line analysis from BUCC EMS packages and/or PSSE study files to validate outputs of control systems.
- Determine whether EMS Test environments can be leveraged in any way.
- Validate that only authorized access attempts are indicated in log file

- **Information Sharing**
  - Forward information (logs, backups, etc) to the ES-ISAC and/or ICS-CERT for further review and analysis. This includes any un-authorized access (electronic or physical) attempts.
  - Inform ISO/RTO/RC and neighboring utilities of incident
  - Contact local law enforcement for assistance with physical security
  - Actions could result in activation of NERC Crisis Plan and/or issuance of a NERC Essential Action Alert
  - Forward any evidence of related activity to ES-ISAC and *regional utilities* for further analysis and communication
  - System Operations and ESP Monitoring personnel should have frequent conference calls to correlate monitored ESP activity and system operations abnormal readings.
  - Utilize system "All-Call" and the RCIS to notify related operating entities of this activity and the need to consider validating readings and conducting conference calls to coordinate major system activities (i.e., opening lines, ramping down generation in a morning pick-up)

- **Personnel**
  - If unmanned, have a second shift man backup control centers.
  - If unmanned, deploy personnel to key substations, blackstart facilities and generation facilities

- All non-essential personnel shall be removed critical facilities (e.g. control centers, substations, generation plants)
- All affected facilities vital to the operation of the BPS should be staffed as needed by security trained and background checked individuals during the notice
- Co-locate Security Monitoring – or Cyber Incident Response team personnel with System Operations – so that the team can quickly assess suspect data/outputs and correlate it to ESP monitoring.
- Perform walk-downs of all critical facilities looking for abnormalities or unusual situations (tags on equipment maintenance ports are properly installed)
- Check seals on physical ports (i.e. maintenance ports) of programmable devices such as smart relays to determine if physical tampering has occurred.
- If “assigned” or “trackable” seals are used to manage access, validate seal information (i.e. serial number, scan code, etc.) to ensure that the proper seal is intact.

- **Forensics**
  - Preserve evidence to the extent possible (keep the system(s) in question in a state that allows for further forensic analysis).
  - All control system logs shall be maintained for 3 years for facilities that have CCAs (this includes non-impacted sites)

# Appendix F: Precursors and Local Indicators of an Unusual Event

Some activities can be a precursor to the start of an actual event. While local indicators can happen routinely, having multiple occur could be a sign of an out the ordinary situation.

**Precursors to Anomalies**

- Reconnaissance activity on public facing web sites, with a focus on harvesting of email addresses or other contact information
- Correlated targeted malware delivery attempts (such as spear phishing) across the industry
- Correlated malware samples contained within the industry
- Observed anomalies along perimeter, guest, remote access or wireless networks
- Anomalies of outbound or egress traffic from highly controlled environments
- Public threats by activist or hacktivist groups
- Geo-political crisis

**Anomalies in EMS/SCADA system application**

- Displays not updating or erratic display update times
- Alarm “heart beat” fails
- Flurry of alarms determined by the system operator to be erroneous
- Flurry of alarms by State Estimator indicating a mismatch between field values and SE.
- Generator units not responding to AGC
- Not able to recover from a Control Performance Standard 1 and 2 excursion
- Large number of RTUs not available for scanning
- AGC or electronic dispatches not matching schedules
- ICCP in-operative
- Sporadic malfunctions of equipment or process

**Anomalies in EMS/SCADA system hardware behavior**

- High disk I/O rate
- Quickly diminishing free disk space
- High CPU utilization
- Undocumented service(s) running
- Slow network response
- Operator consoles loosing connection
- Change in network topology
- Unexpected network traffic
- Unexpected server(s) and firewall(s) restarts

- Unexpected loss of network connectivity, both internal and external
- Change in sound or pitch of equipment

**Anomalies within Substations**

- Alarms associated with relays, communications processors, SCADA
- Indications of physical access to equipment (tamper-proof tape on maintenance ports)
- Changes to relay configurations or settings
- Changes to ports/services on PCs or other equipment in substations (i.e. different from baseline)
- Changes to breaker settings or configurations
- Changes to RTU configurations or settings
- Passwords changed or checked out outside normal change cycle
- Alarms associated with devices unplugged or unauthorized devices connected to secured network (MAC addresses, switch ports normally turned down)
- Loss of RTU / DCS communication to the master EMS
- Change in sound or pitch of equipment

**Anomalies in Situational Awareness**

- Decrease in expected activity
- Similar activity as in previous hour, 24 hours or day that does not appear to match field readings
- Telemetry readings not matching schedules

**Communication from (RTO and/or neighboring utilities, customers)**

- Confirmed cyber security event at another entity
- Alarms associated with RTUs at interconnect points (multiple RTUs)
- Unconfirmed cyber security event
- Customer calls describing outages that do not correspond with normal alarms

**Personnel**

- Multiple personnel absent due to illness
- Erratic or nervous behavior
- Personnel missing or present during unusual times of during the day or shift

# Appendix G: Isolation and Survivability Tactics

None of the suggested actions should be taken without first understanding the operational or situational awareness impact

**Network Isolation**

- Disable non-essential corporate connections to Internet, including e-mail
- Disable backup (dial-up or emergency) connections to Internet
- Disable connections with business partners (point-to-point connections and site-to-site VPNs)
- Disable remote access (dial-up, and client VPN) connectivity connections to internet
- Remove inbound connectivity to critical networks from corporate or business networks
- Remove outbound connectivity from critical networks to corporate or business networks to prevent further propagation

**Operational Isolation**

- Disable AGC and operate using local generator control
- Disable SCADA and Communications networks from Substations and Generation facilities
- Disable communications from Communications Processors in Substations from Intelligent Electronic Devices (IEDs) such as relays.
- Disconnect relays from breakers
- Islanding
- Under Frequency Load Shedding

# Appendix H: Defensive Capabilities

**Voice and Data Communications**

- Telecom Companies (Cellular, POTS, etc.)– loss of RTUs, percentage thresholds
- Company owned copper – loss of RTUs, percentage thresholds
    - Have multiple path technology in place that could use several connection types / ISP's with the communications path using all that are available automatically.
- Multiple facilities/cell areas
- Cell phones / Smart phones – Social engineering, unsolicited inquiries
- Internet Service Providers detecting and dropping or rerouting malicious network traffic.
- Entity Owned Communication Networks (800 MHz, Microwave, Fiber, etc.)
- ICCP or Inter-Company Communications (Voice and Data)– loss of 2 or more simultaneously
- Satellite Communications
- Internal telecommunications facilities (e.g. ICCP.- microwave - local physical attacks (i.e. antennae structure damage)
- Dedicated facilities such as automatic ring downs (ARD) and Hotlines
- Social media – Twitter feeds, Skype, Facebook

Network perimeter defenses (border) – cyber intrusion into control center premise or critical asset premise

- Firewalls
- Intrusion Detection and Prevention systems
- Router Access Control Lists
- Data Diodes (or other methods of isolation – combination of routable and non-routable protocols)
- Vulnerability scanning and configuration management control (scans for changes in settings or configurations)
- Non-routable communications between servers
- Out of band communication to critical equipment (accessible over LAN/WAN and dial-up)
- Real-time logging of events on network and host devices.
- Alarms setup based on defined thresholds for abnormal events such as login fails, privileged account usage, or device probes that result in "access denied messages".
- Ability to query the log database for specific items that may not be in the current alarm pattern

- Security Information Event Management (SIEM) systems that consolidate logs and provide correlation of seemingly unrelated events,

**Physical Defenses or Deterrence**

- Motion detection – motion detector alarms, cameras, floodlights, control house intrusion alarms, loss of oil or over-temp transformer alarms
- Key card access
- Use of biometric controls
- Mantraps or other physical barriers that prevent tailgating
- Use of special locks for gates, equipment
- Increased patrols by law enforcement / contracted security
- Logging of physical access
- Increase access restrictions:
    - Advance notification for visitors
    - Limit access by outsiders to business need
- Increase use of security cameras, video surveillance.
- Staffing levels of key facilities
- Background checks
- Continuous behavioral monitoring
- Random drug testing

**Generation Defenses**

- Use of “Constant Frequency Operations” – previously defined for the Y2k transition.
- Use of “Conservative Operations” to maintain extra capacity
- Day-Ahead Planning – conservative mode unit commitment to maintain extra capacity and responsiveness
- Operation near unity power factor to maintain reactive capability (VAR reserves)
- Blackstart

# Appendix I: CRPA Observations and Recommendations

| Observations and Recommendations |
| --- |
| **Observation 1** - Most of the exercises and mini-programs included aspects of concurrent physical and cyber incidents, a tactic used to bring familiarity to the traditional domain of perimeter compromise to the assessment space. This use of mixed incidents was most prevalent when the participating entity migrated to Internet Protocol-based substation and SCADA operations. The goal was to determine general levels of readiness as they pertained to mapping physical asset break-ins to plausibly impact the cyber infrastructure. All entities had formal process and checklists to manage response to physical break-ins and theft of copper, equipment, and other valuable items. However, none had a process to consider if any technology had been *added* to the environment, such as rogue access points, radios, or other devices that could provide access to the EMS operational domain. |
| **Recommendation 1** - Entities should update standard procedures for facility break-ins to include examination of systems for unauthorized changes to cyber assets. Additionally, entities should conduct system "sweeps" to identify any new equipment that may have been introduce to facilitate unauthorized access to the energy management command and control network. |
| |
| **Observation 2** - Most entities involved in the program had some form of cyber incident response plan in place or in development. In each case, the plans identified and assigned personnel and roles to respond to a cyber incident, but the plans lacked contingency planning in the event key personnel were not available. During the exercises and outreach campaigns, several participants noted that they were unfamiliar with the entire set of incident response activities, such as escalation, points of contact, impact analysis, etc. This observation suggests that, although a first-line of response had been established (and roles assigned), there was no capability to back-fill or cross-pollinate roles during a cyber incident. This issue can increase risk if, during an incident, trained personnel are not available and activities cannot be performed. |
| **Recommendation 2** - The entire response team should be assigned primary and secondary roles, guaranteeing overlap in capabilities should the situation require it. Also, entities should include more group members from each response group in incident response training. This redundancy will provide some depth to the entity's "bench strength" and offer more resiliency. An entity should select a minimum number of people per department who should have incident response training, and ensure that those people receive the necessary training. Cross-train at least two additional staff members as incident response leaders who can take command of incident response activities. |
| |

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| **Observation 3** - Having a corporate capability to interact with local and federal law enforcement during or after a cyber incident is something all entities deemed mandatory. While most organizations had at least one person in place that had some contacts in the law enforcement community, very little of their experience and knowledge had been internalized by the organization in the form of policies and procedures. After action reporting from exercise activity, combined with outreach and entity interviews, suggested that incorporating a law-enforcement communication function in the incident response plan would be useful, and that any experience and relationships entity personnel may have should be leveraged. |
| **Recommendation 3** - Entities should work with local law enforcement to create a pre-populated list of law enforcement activities that could be performed during a cyber event. Establishing a pre-determined communication protocol with law enforcement entities would also be beneficial in helping to understand what law enforcement will do if called to support investigations. Feedback from participating entities suggested including law enforcement in exercise training activities, and proactively working with law enforcement to understand what is required should an actual incident occur. Entities should initiate a cooperative partnership with local Federal Bureau of Investigation or Royal Canadian Mounted Police offices, and include them in the response planning activities. NERC may wish to review any framework development that empowers BPS entities to create a law enforcement communication plan based on known investigative procedures, or suggest the augmentation of NERC CIP language to define the parameters that support law enforcement communications. |
| |
| **Observation 4** - During the exercises, interviews, and after-action discussions, the majority of participants appeared unsure about the necessary involvement of the RC in a cyber incident and are unsure how or when to engage them. |
| **Recommendation 4** - Entities may wish to explore this issue further, as present protocols in place for interaction with RCs may not always include strategies as it pertains to a cyber incident where (a) reliability of BPS operation may be jeopardized, and (b) the communications path to the RC may be an attack vector. Entities are encouraged to work with their RC to establish a set of pre-defined incident response procedures which will determine when to include them in the communication chain during an incident. Moreover, NERC should investigate the protocol regarding entity-RC communications and reporting during cyber duress. |
| |

**Observation 5** - The CRPA covers many aspects of entity operations and looks specifically at security operations for critical cyber assets; also included in the project activities were Primary Control Centers (PCC)/Main Control Centers and Back Up Control Centers (BUCC). A review of the findings indicates that, in many cases, the entity maintains BPS operations across a flat network and, to support redundancy, mirrors activities to a BUCC on that network. As the BUCC receives updates in real time from the systems in the PCC, a potential attack vector to the BUCC is established. Observations show that this architecture could create a situation where a cyber incident can impact mission critical backup data and critical cyber assets in the BUCC. The recovery protocol deployed suggests that should operators need to close the PCC and move to the BUCC, the operational environment at the BUCC would be useless as it has been compromised by association or archived (recovery) data is corrupted.

**Recommendation 5** - Entities should consider expanding cyber protection measures to the communications infrastructure that support primary and backup facility operations. As it is assumed that all critical contingency communication resides behind and within the ESP, entities should consider monitoring the connection between the BCC and PCC for anomalous communications and other potential security-related events.

**Observation 6** - The exercises showed that, while the technical teams were often quick to respond to the cyber incident (and begin their incident response activities), there were situations where no clear incident "leader" emerged to manage the incident on behalf of the whole organization. Key elements that were not coordinated included media relations, customer support, law enforcement, regulatory authorities and reporting agencies, and communications.

**Recommendation 6** - Entities should continue to create and run incident response training exercises which include, and even focus on, management teams.

**Observation 7** - The CRPA exercises, interviews, and after-action reporting demonstrated that the security architecture of vital transmission and distribution assets was constructed with significant security controls. Observers noted that assets are often managed by an internal team with a high level of skill and knowledge pertaining to BPS resiliency and EMS recovery. However, in many cases, the management of an entity's generation element(s) has been outsourced to third parties, resulting in increased response times, reduced control systems knowledge, and an impaired ability to manage energy assets in accordance with the entity's response protocols. These issues created extreme difficulty in managing fast-paced cyber incidents that include generation assets.

**Recommendation 7** - Although these situations can be rare, the risk associated with insufficient security knowledge and response experience in the generation asset domain could prove to be significant during a cyber incident. Entities should consider moving management of all assets within the main EMS/SCADA and IT Engineering groups, resulting in an improvement to the overall management of generation assets.

| |
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| **Observation 8** - Despite the number of public displays of system compromise in recent years, combined with well-known cyber incidents impacting the energy sector, some individual participants remain skeptical about the possibility of a successful cyber attack on their own critical cyber assets, and as an extension, of the BPS cyber infrastructure itself. Participants did concede, however, that participating in scenario-driven exercises that used non-fictitious elements (cyber attack) to force them to test traditional response activities was very useful. |
| **Recommendation 8** - As the threat and risk landscape can change quickly, entities are encouraged to incorporate specific intelligence about their operations into their planning and training agenda. In addition, as part of the risk assessment process, entities could extend their activities to determine actual and plausible threats against their cyber infrastructure and use that data to populate their exercise and training curricula. Training activities for SCADA/EMS operators should be expanded to include general cybersecurity training to all EMS/SCADA IT, Electric System Operations, Corporate IT, and IRT training regimens. |

# Appendix J: Case Studies

***Breaking Air Gap Myths About Control System Inaccessibility - Stuxnet***

Just because there is an "air gap" doesn't mean a control system is inaccessible to adversaries. Stuxnet is a great example. A USB thumb drive can be transported from an infected host machine and inserted into the target network that is air-gapped. Then stuxnet can propogate on the local target network via multiple exploits. That propagation results in forming a hostile Peer to Peer (P2P) network which operates on the probability of finding resident hosts with indirect or direct internet accessibility. It then utilizes these hosts to establish an indirect Command and Control (C2) bridge for hostile control. In sum, USB served as not only the delivery mechanism but also to establish a network of hostile P2P relationships within the target network.

***Another Example, Breaking Air Gap Myths About Control System Inaccessibility – Buckshot Yankee***

SIPRNET is Department of Defense's (DoD) Secret-level network. This network is commonly perceived as completely air-gapped, yet in 2010 Deputy Defense Secretary William Lynn publicly disclosed a 2008 worm infestation on the network. The DoD response to this infestation was called Buckshot Yankee. Also in 2010, well-known former counter terrorism official Richard Clarke released a book entitled "Cyber War." Clarke gave a more detailed account of Buckshot Yankee. The delivery mechanism was USB insertion, much like stuxnet, but its C2 method was novel. Instead of P2P C2, Buckshot Yankee relied on sneaker-net C2. The infected thumb drive payload carried not only the malware worm but also a data file. This data contained requests and responses which serve as a C2 channel to the next internet connected devices the USB is inserted into. The result: USB creation of an effective hostile sneaker-net C2 channel across the perceived air gap which "secures" the target network. The bottom line: USB established a delivery mechanism within an air-gapped network and then sneaker-net connectivity enabled by repeated usage of USB devices between both air-gapped and non-air-gapped networks.

***TAKE AWAY, what these examples say about Cyber Attack awareness…***

Techniques such as utilizing USB devices as delivery mechanisms to enable hostile penetration of targeted "secure" control networks is widely known. Approaches of establishing hostile C2 channels across the gap using techniques such as P2P or sneaker-nets are less well known.

Techniques like these mean that defensive measures limited to reliance on air gaps need to be evaluated skeptically. Other advanced and novel means of hostile penetration, and the means to offer effective layered defense against them, must be considered to achieve true control network and device security and true risk management. These observations point towards integrated consideration of policies, procedures, system design, operational approaches, intrusion detection, anomaly, monitoring and awareness technologies which deliver a capability

to understand own network health, vulnerabilities and mitigation options. Take a proactive and more informed view towards the challenges and opportunities to enhance your security by keeping apprised of hostile techniques, tactics and procedures (TTP) like the two illustrative examples above.

***Disruption through swarming***

Creating an open call for volunteers in an ad-hoc, extemporaneous way to do something is popularly known as crowd sourcing. It's leaderless or structure-less network of people coming together for a common purpose and then disbanding. Adversaries use this tactic. The Anonymous (a loose knit global hacktivist group) hive is the personification of this but there are others.

In 2008, at the onset of war between Russia and Georgia, a distributed denial of service attack (DDoS) began against government websites. As hostilities began, this was extended to Georgian media websites covering the hostilities. These various DDoS attacks lasted for hours and had a peak of over 800Mbps. A few months later an analysis under the moniker of "Project Grey Goose" was released. This report outlined the coordination ground for these DDoS to a website called stopgeorgia.ru. This was a password-protected forum launched within 24 hours of hostilities. These DoS attacks were interspersed with website defacements posting pro-Russian propaganda.

These DoS activities and defacements were seemingly self-organized or crowd sourced on sites such as stopgeorgia.ru. Many believe the Russian government was in the background of these pro-Russian hackvists. At the very least, the Russian government appeared to condone the activities as evidenced by their clear restraint in not launch any investigation of the attacks.

Anonymous uses surprisingly similar tools to organize (online forums) - and similar tools to launch attack activity (denial of service attacks). Their tool of choice is called Low Orbit Ion Cannon (LOIC). LOIC is an application designed to launch DDoS attacks. LOIC by itself is uninteresting. It's the forums that are interesting. You'll see a long list of independently organized "operations" or "ops". Each of those operations are public and open to the community to comment on. There are dozens of ops at any given time, most of them become background noise. Others take off and develop a life of their own. The HBGary Saga is a good example of a successful op. But for each successful op there are countless that don't see the light of day. Combine this with the LOIC tool: when you give it to the hands of 10,000 who point it at the same target then you have a distributed denial of service. This is what was used in Operation Payback when Anonymous attacked PayPal and others after they refused to provide services to wikileaks.

This is a noteworthy tactic as indications are that it is employed by a wide range of adversaries. Pro Russian groups used it as a propaganda and disruption tool, and Anonymous continues that tradition.

***TAKE AWAY is that swarming is a practice that has been observed, Crowd sourcing and social media techniques are easily available to motivated groups that may seek to use them for distributed denial of service disruption.***

***Off the shelf tools***

There exists an ecosystem of tools available to the adversaries. Some of these are dual use for offensive and defensive purposes. Some of these tools are merely used at research levels, others for active attacks. Fuzzing tools and Security debugging tools such as olly or ida pro - which are development environments. These can pinpoint flaws in software and ultimately lead to exploit code that can be weaponized.

LAMP stands for Linux Apache Mysql and PHP. It is a "vanilla" OS, Webserver, SQL server and a web application language and how those four off the shelf technologies can be combined for rapid web development. LAMP is the model being packaged and sold by malicious underground adversaries in order to exploit people. These are known as exploit kits. Exploit kits use LAMP to set up malicious web pages, and use those pages to attack web browser and client components. The exploit kit also keeps track of the overall success rate. The kits create malicious iframes that will attempt to use a series of several exploits all at once in order to execute a malicious payload on the target machine. These iframes are windows cut into the webpage that allow visitors to view another page on the site or off the site without reloading the entire page. The exploit kit will also track victims by IP address, country, browser, OS-level, etc…

These malicious pages are delivered through vectors such as search engine optimization (SEO) and Phishing attacks.

Contagio dump (a web based collection of the latest malware samples, threats, observations and analyses) is tracking 64 versions of 42 unique exploit kits in the wild. Most of these contain between 10-20 exploits and each kit is sold for between $1000 to $2000. These 64 unique exploit kits have a total of over 100 unique exploits! Mostly targeting flash, adobe, quicktime, java, or browser vulnerabilities. Tools other than exploit kits also exist. LOIC is another off the shelf tool to be aware of. Additionally, there are Trojans, such as poison ivy, zeus, TDL, and others, which threat actors can purchase or gain use of through underground or criminal communities.

***TAKE AWAY is that exploit kits are ubiquitous and inexpensive for criminal groups to obtain and utilize. Software development quality control and layered defense in depth, combined with own systems awareness are key defensive measures.***

***Lateral Movements***

Adversaries with long-term motives will typically focus in on first gaining access to a target network, then finding target hosts on the network which enable network understanding. This tactic is generically referred to as moving laterally in the compromised network. This is where it can be tough to remove an adversary on your network because the adversary is in several places.

The tactic - and both Google Aurora as well as the RSA breaches saw this tactic used - starts with patient zero. Once patient zero is compromised the adversary begins compromising other workstations or servers with back doors. Adversaries will then use those backdoors and stand up their operations. One workstation may host various attacker tools: another workstation will be for data staging if the aggressor plans on finding and exfiltrating data. Yet another box is simply given a back door and not touched in case the aggressor loses access to the other boxes. Aggressors may continue lateral movements as they seek long-term objectives and escalate priviledges on the network.

Lateral movement typically occurs through a technique such as Passing the Hash. To illustrate, if an attacker gains access to a target user workstation and the user happens to be a local administrator, the goal becomes to jump from this springboard workstation to a print server and plant a “back door.” This is convenient because the attacker already knows the print server hostname since the user has access to it. What might not be known to the attacker is the target user domain password nor whether hi account has access to interactive sessions with the print server. Attackers may rely on the fact that Windows has a core OS service running known as Local Security Authority. This service caches the users and associated password hash data after a user has authenticated to the local system. The adversary can then utilize a tool known as Wondows Credential Editor (or metasploit…) and dump password hashes. This is not the plain text password. The password is not needed. Wondows Credential Editor can utilize this NTLM hash and start processes as the attacked user. The attacker uses Windows Credential Editor and dumps the cached hashes in LSA. The attacker identifies an account called “service Veritas.” That shines out to the attacker because Veritas is a backup software solution. If the backup software is using this service, there is a high likelihood that it is domain admin or nearly equivalent. Windows Credential Editor allows the attacker to use this hash and pass it on to the system to run processes as that user. On the local machine, he can then remotely connect to boxes as that service account. That’s how backdoors can be planted. Subsequently, one could come back to the print server and list hashes that are cached on the print server. If the domain equivalent  user has recently talked to the print server, that hash can be stolen and used as an attacker enabler for easy internal movement within the target network environment.

***TAKE AWAY is that a foundational defensive element of strategy for every organization should be development and maintenance of own asset and own system baseline configuration and operational states, as well as own systems operational awareness. Obtaining and keeping good forensic and log data can be very crucial to effective and sustainable defensive posture. Often a few Indicator of Compromise (IOC’s) can be developed around a few key, but important, departures or anomalies from normal operating parameters. These can be used to identify and triage attempts at compromise.***

# Appendix K: Task Force Goals and Objectives

The goals and objectives of the CATF are:

| Goals | Objectives |
|---|---|
| Review current situation and capabilities | 1. Consider the ability of entity system operators and cyber security analysts to detect and respond to a coordinated cyber attack.<br><br>2. Consider the extent to which entities may not isolate critical cyber systems from other business or Internet-facing systems, and the extent to which this increases the vulnerability of their systems.<br><br>3. Consider opportunities to isolate, prevent further propagation, or otherwise protect cyber systems and bulk power system assets.<br><br>4. Consider the capabilities of voice and data communications tools and energy management systems, with a focus on which minimum functional needs system operators must retain and the alternative methods to acquire or maintain this capability even in a reduced state.<br><br>5. Consider staffing capacity, challenges, and safety.<br><br>6. Assess the adequacy of current CIP cyber security practices under a coordinated cyber attack scenario. |
| Perform needs assessment | 7. Identify the functions needed to support reliable power system operations that would be particularly challenged under a coordinated cyber attack scenario. |
| Develop alternative solutions | 8. Assess the options, benefits, and costs associated with isolating critical cyber systems (i.e. control systems, energy management systems, protections systems, and their networks). Consider complete or virtual (e.g. virtual private network) separation.<br><br>9. Propose a range of alternative solutions to enhance operating capabilities, including estimated costs and effort to develop and maintain this capability. Identify the residual |

| | |
|---|---|
| | risks that may be associated with each of these solutions. |
| Coordinate Solutions | 10. Assist in outreach efforts to educate regulators, organizations, and other infrastructures in better understanding the electricity sector's preparations to address these threats. |
| Recommend Solutions | 11. Recommend potential practices or programs for use by NERC or individual entities. Create scalable drill templates that registered entities could utilize to train personnel and enhance current restoration and operating protocols. |

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# Announcement

## NERC Releases Two Reports Focused on High-Impact, Low-Frequency Risks

May 22, 2012

**WASHINGTON, DC** – The North American Electric Reliability Corporation (NERC) released two technical reports recently as part of its Critical Infrastructure Strategic Roadmap to address high-impact, low-frequency events that have the potential to affect the reliability of the North American bulk power system.

The two reports address cyber attack incidents and severe impact resilience, and provide guidance to the industry on enhancing and protecting the grid against debilitating events.

"While NERC and the industry have been actively addressing critical infrastructure issues for many years, these reports help address particularly severe events with the potential to impact large portions of the grid and disrupt service to customers for an extended period of time," said Gerry Cauley, president and chief executive officer at NERC. "Increasing our understanding of these events allows us to put necessary and appropriate solutions in place that better ensure the reliability of the bulk power system.

The *Cyber Attack Task Force* report provides guidance to prevent, deter, detect and respond to a coordinated cyber attack. The report describes aspects of cybersecurity that could be challenged through a sophisticated cyber attack and provides options to protect the assets, systems and networks critical to the reliable operation of the bulk power system.

The *Severe Impact Resilience: Considerations and Recommendations* report provides guidance to asset owners and operators on enhancing the resilience of the bulk power system to potentially catastrophic events, such as coordinated

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physical or cyber attacks or a severe geomagnetic disturbance. The report describes the concept of a "new normal," where the bulk power system is restored and operated at a reduced state of reliability for months or possibly years.

A complement of reports was developed in response to recommendations from a June 2010 joint NERC and Department of Energy report - *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System*. The HILF report focused on a class of rare risks to the bulk power system that were identified as part of NERC and the Electricity Sub-Sector Coordinating Council (ESCC) roadmap for addressing these types of events. The HILF report found that the best approach to these events would be through an organized combination of industry-led task forces and NERC staff initiatives.

The ESCC, which is chaired by Cauley, is made up of electricity industry chief executive officers from across North America. The ESCC fosters sector-wide initiatives to improve the reliability and resilience of the electricity sector, including physical and cybersecurity infrastructure.

Other task force reports developed in response to the roadmap include the *Spare Equipment Database* report and the *2012 Special Reliability Assessment: Effects of Geomagnetic Disturbances on the Bulk Power System* report.

###

*The North American Electric Reliability Corporation's mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission in the United States to establish and enforce reliability standards for the bulk-power system. NERC has equivalent relationships with provincial and federal authorities in Canada. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast, and summer and winter forecasts; monitors the bulk power system; and educates, trains and certifies industry personnel. Learn more at www.nerc.com*

**From:** Kimberly Mielcarek
**To:** Kimberly Mielcarek
**Subject:** NERC Announcement - NERC Releases Two Reports Focused on High-Impact, Low-Frequency Risks
**Date:** Tuesday, May 22, 2012 11:12:51 AM

# Announcement

## NERC Releases Two Reports Focused on High-Impact, Low-Frequency Risks

**Click for Announcement, Cyber Attack Report, Severe Impact Resilience Report**

**WASHINGTON, DC** – The North American Electric Reliability Corporation (NERC) released two technical reports recently as part of its Critical Infrastructure Strategic Roadmap to address high-impact, low-frequency events that have the potential to affect the reliability of the North American bulk power system. The two reports address cyber attack incidents and severe impact resilience, and provide guidance to the industry on enhancing and protecting the grid against debilitating events.

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# Severe Impact Resilience: Considerations and Recommendations

## Severe Impact Resilience Task Force

Board of Trustees Accepted: May 9, 2012

RELIABILITY | ACCOUNTABILITY

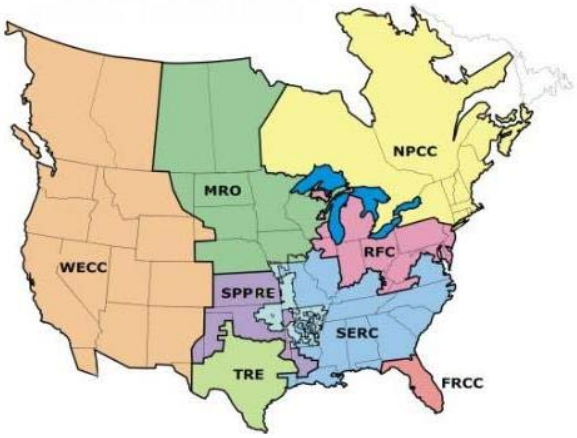





# NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to enhance the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the BPS; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American BPS, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the BPS within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.




| Table A: NERC Regional Entities | |
|---|---|
| **FRCC**<br>Florida Reliability Coordinating Council | **SERC**<br>SERC Reliability Corporation |
| **MRO**<br>Midwest Reliability Organization | **SPP**<br>Southwest Power Pool, Incorporated |
| **NPCC**<br>Northeast Power Coordinating Council | **TRE**<br>Texas Reliability Entity |
| **RFC**<br>Reliability*First* Corporation | **WECC**<br>Western Electricity Coordinating Council |

**Note:** *The highlighted area between SPP and SERC denotes overlapping regional area boundaries: For example, some load serving entities participate in one region and their associated transmission owner/operators in another.*

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NERC's reliability standards are also mandatory in Nova Scotia and British Columbia. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

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# 1.0 Executive Summary

The North American bulk power system (BPS) is one of the most critical of infrastructures, vital to society in many ways, but it is not immune to severe disruptions that could threaten the health, safety, or economic well-being of the citizens it serves. The electric power industry has well established planning and operating procedures in place to address "normal" emergency events (e.g., hurricanes, tornadoes, ice storms) that occur from time to time and disrupt electric reliability. However, the electricity industry has much less experience with planning for and responding to high-impact events that have a low probability of occurring.

To help the electricity industry better understand these low probability risks, NERC and the U.S. Department of Energy (DOE) issued a report titled, "High-Impact, Low-Frequency Event Risk to the North American Bulk Power System"[2]. Subsequently, the NERC Board of Trustees approved a Coordinated Action Plan under the leadership of the NERC Technical Committees to establish four Task Forces to address this work. This report provides the conclusions of the Severe Impact Resilience Task Force (SIRTF).

The report provides guidance to industry asset owners and operators (entities) in the form of recommendations to enhance the resilience of the bulk power system. Three high-impact, low frequency (HILF) scenarios were specifically considered as the initiating events, but the recommendations in this report may be applicable to any severe-impact scenario.

- **Coordinated physical attack** – A coordinated physical attack on key nodes of the BPS critically disables difficult to replace equipment in multiple generating stations or substations and could have a significant effect on the remainder of the system. A prolonged period of time is required to fully restore the BPS to normal operation.
- **Coordinated cyber attack** – A coordinated disruption disables or impairs the integrity of multiple control systems, or intruders take operating control of portions of the BPS such that generation or transmission system is damaged or mis-operated.
- **Geomagnetic disturbance**[3] – A severe geomagnetic disturbance damages difficult to replace generating station and substation equipment and causes a cascading effect on the remainder of the system. A prolonged period of time is required to fully restore the BPS to normal operation.

The report offers 33 key recommendations that are of a planning and operational nature, and entities are strongly encouraged to consider these from a strategic and leadership perspective, in particular:

- Enhance existing restoration drills and exercises to incorporate HILF scenarios that include interdependencies with other critical infrastructures such as telecommunications.

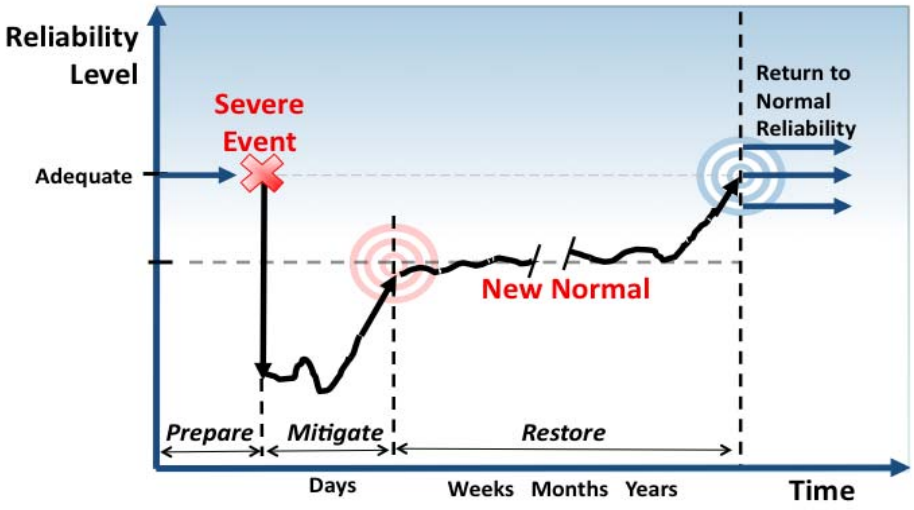
[2] Ref. High Impact Low Frequency report http://www.nerc.com/files/HILF.pdf

[3] Ref. *Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System* http://www.nerc.com/files/2012GMD.pdf. This report concluded that the loss of reactive power is the most likely outcome from a severe solar storm centered over North America.

- Recognize that plans and operating practices will need to be continually assessed and adjusted as necessary over an extended period that could last months or years following a severe event.
- Involve neighboring jurisdictions and government agencies by sharing plans and building a better understanding of how these plans will be coordinated and implemented.

## Understanding a Severe Event

The guidance offered in this report is intended to reach beyond the emergency response capabilities entities typically have in place. To emphasize this, the SIRTF developed two important concepts that run throughout this report; Severe Event and New Normal. A Severe Event is an emergency situation so catastrophic that complete restoration of electric service is not possible. The BPS is operated at a reduced state of reliability and supply for months or possibly years through the New Normal period as illustrated below.




### Enhancing Resilience

By definition, a Severe Event will present enormous challenges as entities within the electricity industry strive to restore and maintain reliable operations under rapidly changing circumstances never before experienced. It will not be possible to meet all electricity consumers' demands for rapid restoration of service as entities prioritize their work with limited resources. The recommendations and suggestions offered throughout this report are intended to prompt BPS entities to develop their own approaches and flexible plans that would be applicable under a wide variety of circumstances. These suggestions are in the form of industry guidelines that describe practices that may be used by individual entities according to local circumstances, as opposed to standards.

## Recommendations

The SIRTF has considered what aspects of emergency operation and restoration would be particularly challenged through a Severe Event and considered options to enhance the resilience of the BPS. Entities are encouraged to consider how they might apply the recommendations offered in this report to their own circumstances in a Severe Event scenario. Entities are encouraged to test their plans through drills or exercises that build further on the Severe Event scenarios.

The following summarizes the key recommendations of this report and are described in the body of the report in further detail.

## Operations

The Operations section of this report discusses the many challenges associated with operating the BPS following a Severe Event. Rather than operating as part of a large interconnected (and therefore more stable) grid, system operators may need to manage a number of small electrical islands and implement load shedding or rotating blackouts for extended periods of time (weeks, months or years). The Operations section proposes that entities consider the following key recommendations.

1. Consider which entities would take the independent actions and the tools needed to stabilize islands when communications capability is severely disrupted or unavailable.
2. Consider how operating reserve would be managed during islanded operation and frequent periods of insufficient supply to meet demand.
3. Consider ways to adopt and apply the terms critical load and priority load across all BPS entities to improve consistent use during a Severe Event.
4. Consider alternate means to dispatch generation if normal automated systems, including automatic generation control, are unavailable.
5. Consider if or how variable generation would be dispatched through restoration and islanded operation.
6. Consider enhancing regular restoration drills and exercises to train staff on communication protocols and independent control actions in the event of loss of or degraded telecommunications.
7. Consider using more extreme exercise scenarios that involve simulated rotating blackouts and islanded operations on a larger scale and for extended periods of time.

## Monitoring the Bulk Power System

The Monitoring the BPS section discusses the challenges associated with maintaining situational awareness in order to operate the BPS following a Severe Event. A Severe Event may disrupt the flow of data, tools, or facilities needed to operate the BPS. Alternate mechanisms and processes would be needed to maintain a wide area view of situational awareness when it is more important than ever. The Monitoring the BPS section proposes that entities consider the following key recommendations.

8. Consider developing processes to quickly study island configurations and develop suitable temporary operating limits.
9. Consider developing processes to monitor BPS flows in the absence of reliable automated systems and communications.
10. Consider the simultaneous loss of primary and backup control centers and how essential functions will continue to be performed.

## Communications

The Communications section discusses the challenges associated with restoring and operating the BPS when communications facilities are severely degraded or unavailable. The Communications section proposes that entities consider the following key recommendations.

11. Consider installing renewable generation (e.g., wind, solar) or expanding fuel storage capabilities at critical BPS facilities to supplement standby generators.
12. Consider alternate means to communicate when primary means of communication are completely unavailable for extended periods of time.
13. Consider robust training, drills, and exercises to fully test critical restoration steps using alternative voice and data communications (e.g., satellite telephones).

## Short-term and Long-term System Planning

The Short-term and Long-term System Planning section discusses the challenges associated with providing sufficient personnel and facilities to prepare the necessary system studies and plans needed to support restoration and long-term recovery. This section proposes that entities consider the following key recommendations.

14. Consider the potential loss of planning resources (e.g., equipment, data) as well as damage to the system. Review business continuity plans to ensure that system planning resources are adequately considered.
15. Consider the appropriate use of key system planners who may be required immediately, and for prolonged periods, to perform studies not previously considered.
16. Consider performing selected studies in advance (e.g., equipment interchangeability) that could help speed restoration.
17. Consider the spare equipment critical to BPS restoration and ways to improve availability of these spares.

## Protection and Control

The Protection and Control section discusses the challenges associated with safely operating the BPS as its configuration continues to change to respond to the loss or unavailability of critical elements. This section proposes that entities consider the following key recommendations.

18. Consider ways to implement large-scale changes in system protection schemes to support islanded operation and changing BPS configurations, and what decision points would be needed.
19. Consider ways to quickly reconfigure relay settings in the event large-scale changes are needed.

## Interdependencies with Other Critical Infrastructures

The Interdependencies with Other Critical Infrastructures section discusses the contribution and impact that other industries such as communications, oil and natural gas, and water have on the ability of the electricity industry to restore and operate the BPS. This section proposes that entities consider the following key recommendations.

20. Consider working with communications service providers to identify which of their facilities are critical to BPS operations. Determine which BPS and distribution facilities supply them and what backup power capacity is in-place (e.g., batteries, standby generators).
21. Consider alternate suppliers, transportation paths, and agreements to support generating station fuel supply chains (e.g., coal, natural gas).
22. Consider working with information technology service providers that are critical to BPS operations and consider augmenting the subject matter expertise of staff and suppliers to support these systems.
23. Consider alternate means to supply BPS power to nuclear plants and confirm these loads as critical to restoration and public safety.

## Coordination with Government

The Coordination with Government section discusses the need to build effective relationships with the appropriate government agencies in order to help manage serious public health and safety issues. This section proposes that entities consider the following key recommendations.

24. Confirm the roles, authorities, and points of contact between BPS entities and as appropriate, local, state/provincial, and federal governments.
25. Coordinate with local and state/provincial government authorities and consumer stakeholders to identify priority loads to mitigate the impact on public health and safety.
26. Consider developing a list of regulatory exemptions or waivers that will materially improve restoration and operation (e.g., plant emissions, truck driver hours) and consult with state/provincial and federal agencies.

## Taking Care of People

The Taking Care of People section discusses how entities can assist with the extraordinary demands that employees and their families may face. This section proposes that entities consider the following key recommendation.

27. Consider ways to support the health, safety, and well-being of personnel and their families in the face of extraordinarily demanding circumstances.

## Logistics and Self-Sustained Operations

The Logistics and Self-Sustained Operations section discusses the challenges associated with the logistics of acquiring the equipment needed to restore and operate the BPS. This section proposes that entities consider the following key recommendations.

28. Consider with fuel suppliers ways to prioritize the supply and delivery of fuel for emergency standby generators and essential work vehicles.
29. Consider how your business continuity or disaster recovery plan would change if you are unable to rely on mutual support arrangements.

## Preventing and Responding to Physical Attacks

The Preventing and Responding to Physical Attacks section discusses the unique challenges associated with physical attacks. This section proposes that entities consider the following key recommendations.

30. Consider actions that can be taken to protect BPS assets by involving local communities and law enforcement (e.g., reinforcing their awareness of BPS facilities that are critical to operations).
31. Consider ways to improve security when designing or refurbishing existing BPS facilities.
32. Consider ways to improve coordination and cooperation with local/state/provincial law enforcement.

## Emergency Financing

The Emergency Financing section briefly discusses the challenges associated with the extraordinary requirements for funds needed to restore the BPS when major facilities need to be rebuilt or replaced. This section proposes that entities consider the following key recommendation.

33. Consider how extreme financial challenges will be addressed in consultation with financial institutions, suppliers, and government agencies.

## Conclusions

This report addresses important aspects related to enhancing the resilience of the bulk power system in the face of a Severe Event. It provides entities with practical options to enhance their capabilities to prepare, mitigate and restore the operation of the bulk power system.

## Recommendations for Entity Action

This report examines the aspects of emergency operation and restoration that would be particularly challenged through a Severe Event and provides options to enhance the resilience of the bulk power system. The suggestions offered throughout this report are intended to prompt entities to develop their own approaches and flexible plans that would be applicable under a wide variety of circumstances. This report considers all aspects of resilience; robustness, resourcefulness, rapid recovery, and adaptability. Entities are encouraged to critically examine their current capabilities, and to consider what else they may need to do to manage restoration and operations during a Severe Event.

While the report offers 33 key recommendations that are of a planning and operational nature, entities are strongly encouraged to consider these from a strategic and leadership perspective, in particular:

- Enhance existing restoration drills and exercises to incorporate Severe Event scenarios that include interdependencies with other critical infrastructures such as telecommunications.
- Recognize that plans and operating practices will need to be continually assessed and adjusted as necessary over an extended period that could last months or years following a Severe Event.
- Involve neighboring jurisdictions and government agencies by sharing your plans and building a better understanding of how these plans will be coordinated and implemented.

## NERC's Reliability Standards under a Severe Event

While this report does not propose that new standards be developed to address a Severe Event, as entities consider and implement the recommendations in this report there may be opportunities to enhance existing standards.

The SIRTF discussed the applicability of the NERC[4] standards through a Severe Event, and whether entities should be exempt from possible compliance actions[5] under these circumstances. The SIRTF reviewed the NERC standards and concluded that standards support safe and reliable operation and should be applicable during a Severe Event. While it is conceivable that during a Severe Event an entity will violate certain standard requirements given the intensity of planning and operating challenges through the New Normal period, it would be impossible to predict these circumstances in advance.

[4] Ref. NERC Standards, http://www.nerc.com/page.php?cid=1|7

[5] NERC has the legal authority to enforce compliance with NERC Reliability Standards, which it achieves through a rigorous program of monitoring, audits and investigations, and the imposition of financial penalties and other enforcement actions for non-compliance.

On balance, the SIRTF concluded that entities do not need guidance on the applicability of standards during a Severe Event. Although a Severe Event may put entities in a position where they cannot comply with all standards, entities are in the best position to "do the right thing" for reliability and public safety, and self-report any violation of NERC standards as time and circumstances permit.

## Acknowledgements

This report was prepared by a team of industry subject matter experts with a broad understanding of what is needed to respond to emergency situations to reliably restore and operate the interconnected bulk power system. They contributed their knowledge, experience, and time to the SIRTF in technical areas such as power system operation, transmission planning, generating plant operation, protection and control, distribution operations, communications, logistics, emergency planning, crisis response, and cyber and physical security.

Members of the SIRTF Report Drafting Team are identified in Appendix 7 of this report.

Many other SIRTF members provided valuable feedback and are identified in Appendix 6.

# 2.0 Introduction

The North American bulk power system (BPS) is one of the most critical of infrastructures and is vital to society in many ways. The electric power industry has well established planning and operating procedures in place to address the "normal" emergency events (e.g., hurricanes, tornadoes, ice storms) that occur from time to time and disrupt electricity reliability[6]. However, the electricity industry has much less experience with planning for and responding to high-impact events that have a low probability of occurring or have not yet occurred.

To help the electricity industry better understand these low probability risks, in June 2010, NERC and the U.S. Department of Energy issued a report titled, "*High-Impact, Low-Frequency Event Risk to the North American BPS*"[7]. In November 2010, the NERC Board of Trustees (BOT) approved the Electricity Sub-sector Coordinating Council's (ESCC) *Critical Infrastructure Strategic Roadmap*[8] that provides the framework to identify the actions needed to enhance reliability and resilience under these high-impact low-frequency (HILF) scenarios. At the same time, the NERC board approved a *Coordinated Action Plan*[9] developed by NERC and the leadership of the NERC Technical Committees that identifies specific initiatives, key deliverables, and milestones to implement the ESCC's Strategic Roadmap. The Coordinated Action Plan identified four Task Forces needed to address this work. This report provides the conclusions of one of them – the SIRTF.

The SIRTF was established in December 2010 by the NERC Operating Committee to develop guidance and options to enhance the resilience of the bulk power system to withstand and recover from three severe-impact HILF scenarios:

- Coordinated physical attack
- Coordinated cyber attack
- Geomagnetic disturbance[10]

This effort has challenged the SIRTF in a number of ways.

- The industry has already demonstrated its ability to respond to large-scale emergencies such as the 2003 Northeast Blackout, Hurricane Katrina and more recently Hurricane Irene using flexible response plans that are designed to be effective regardless of the cause or

[6] Ref. NERC Adequate Level of Reliability
http://www.nerc.com/docs/standards/Adequate_Level_of_Reliability_Defintion_05052008.pdf
[7] Ref. High Impact Low Frequency report http://www.nerc.com/files/HILF.pdf
[8] Ref. Critical Infrastructure Strategic Roadmap
http://www.nerc.com/docs/escc/ESCC_Critical_Infrastructure_Strategic_Roadmap.pdf
[9] Ref. Coordinated Action Plan
http://www.nerc.com/docs/ciscap/Critical_Infrastructure_Strategic_Initiatives_Coordinated_Action_Plan_BOT_Apprd_11-2010.pdf
[10] Ref. *Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System* http://www.nerc.com/files/2012GMD.pdf. This report concluded that the loss of reactive power is the most likely outcome from a severe solar storm centered over North America.

consequences of the event. As a result, some entities may feel they are already prepared and nothing more needs to be done.

- By definition, high-impact, low-frequency (HILF) events have rarely or never occurred, and therefore it is very difficult to determine with confidence what additional action is required even by industry experts who are responsible for planning and operating the BPS through extreme emergency events. The Tohoku, Japan earthquake and tsunami that devastated the Fukushima nuclear plant is a vivid reminder that HILF events can occur.
- The postulated HILF events could cause service disruptions lasting weeks, months and perhaps years – well beyond the industry's experience over the past 100 years of reliable operation.

The SIRTF has recognized these challenges and through this report offers the electricity industry a wide range of suggestions and ideas. The diverse nature of HILF events does not lend itself to technical engineering solutions broadly applicable across the electricity industry. Therefore, the report does not propose mandatory requirements. Instead, the report offers suggestions and ideas to entities that own or operate the BPS. Entities are encouraged to consider these suggestions and apply them according to their own local circumstances and needs.

The SIRTF considered what aspects of emergency operation and restoration would be particularly challenged through these severe-impact events, and considered options to enhance the resilience of the BPS. In many cases, the suggestions can be applied to any HILF scenario, regardless of the specific threat.

## 2.1 Background and Key Concepts

At an early stage in its work, it became apparent that SIRTF members had different experiences and therefore no common view of what is meant by terms such as "severe impact" event, "resilience", and "New Normal" operation. The SIRTF needed to define these terms so that members would have a common platform from which to propose solutions that build on the electricity industry's current ability to respond to emergencies and prepare for worse in a consistent manner.

### 2.1.1 Use of Terms

A number of technical terms related to the planning and operation of the BPS are used throughout this report. Please refer to the NERC Glossary of Terms[11] for definitions.

### 2.1.2 Understanding a Severe Impact Event

A severe impact event (Severe Event) means that complete restoration is not possible and the BPS is operated at a reduced state of reliability and supply for an extended period of time, for months or possibly years – a New Normal. The following describes a Severe Event; one that stresses the electricity industry's capabilities well beyond its already robust emergency response capabilities.

[11] Ref. NERC Glossary of Terms http://www.nerc.com/files/Glossary_12Feb08.pdf

### 2.1.3 Impact of a Severe Event on the Bulk Power System

- The event is beyond the planning criteria provided by NERC planning standards[12], such as System Performance Following Extreme BES Events.
- The event is beyond the scenarios typically exercised by entities as part of the NERC Emergency Preparedness and Operations standards[13].
- It is expected to take six months to a year to return the BPS to pre-event operations.
- As a result of insufficient generation and transmission resources, system operators must shed load without advanced notice and regularly implement rotating blackouts to manage BPS reliability.
- The duration and magnitude of these rotating blackouts have a direct societal impact and risk further degradation to the BPS as other critical infrastructures are affected by the electricity disruptions.
- Multiple information technology and communications systems have failed – entities contend with issues that restrict the ability of system operators to effectively communicate, operate, and monitor the BPS.
- The event is persistent or recurring throughout the mitigation and restoration phases, further hindering recovery and restoration.

### 2.1.4 Impact of a Severe Event on Society

- The media or government authorities describe the magnitude of the event using words such as “catastrophe”, “disaster” or “massive disruption”.
- BPS entity staff experience a high degree of physical and psychological demands for an extended period of time.
- The safety and well being of large numbers of the public, entity staff, or their families are at risk.
- The resources required to respond exceed the financial capacity of some entities.

### 2.1.5 Understanding Resilience

“Resilience” is generally defined as the ability to recover or adjust to misfortune or change. More specifically, the ASIS SPC.1-2009 standard on Organizational Resilience[14] defines, “Resilience is the ability of an organization to resist being affected by an event or the ability to return to an acceptable level of performance in an acceptable period of time after being affected by an event.” In recent years, in the context of strategies needed to enhance the reliable operation of critical infrastructures, resilience has come to be valued as much as protection. But what exactly is meant by resilient critical infrastructures? How is resilience measured and how do we determine how much is needed?

[12] Ref. NERC standard TPL-004, ref. http://www.nerc.com/files/TPL-004-0.pdf
[13] NERC Emergency Planning and Operations standards, ref. http://www.nerc.com/page.php?cid=2|20
[14] ASIS SPC.1-2009, http://www.asisonline.org/guidelines/ASIS_SPC.1-2009_Item_No._1842.pdf

In October 2010, a study group[15] of the National Infrastructure Advisory Council issued its report "*A Framework for Establishing Critical Infrastructure Resilience Goals*[16]". The report provides a broader construct for resilience originally conceived by resilience expert Stephen Flynn. The construct is based on four features organized in a sequence of events prior to, during, and after a Severe Event.

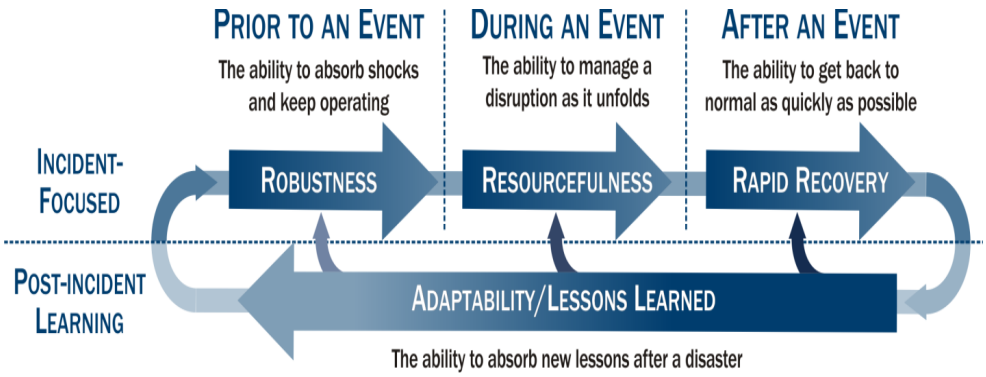
### Infrastructure Resilience

Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event.

[15] The NIAC Study Group included a number of representatives from the electricity industry, including several members of the Electricity Sub-sector Coordinating Council.

[16] Ref. http://www.dhs.gov/xlibrary/assets/niac/niac-a-framework-for-establishing-critical-infrastructure-resilience-goals-2010-10-19.pdf

**Figure 1: NIAC Resilience Construct**




| Table 1: NIAC Resilience Construct | |
|---|---|
| **Sequence** | **Feature** |
| **Prior to an Event** | **Robustness**—The ability to keep operating or to stay standing in the face of disaster. In some cases, it translates into designing structures or systems to be strong enough to take a foreseeable punch. In others, robustness requires devising substitute or redundant systems that can be brought to bear should something important break or stop working. Robustness also entails investing in and maintaining elements of critical infrastructure so that they can withstand low-probability but high-consequence events. |
| **During an Event** | **Resourcefulness**—The ability to skillfully manage a disaster as it unfolds. It includes identifying options, prioritizing what should be done both to control damage and to begin mitigating it, and communicating decisions to the people who will implement them. Resourcefulness depends primarily on people, not technology. |
| **After an Event** | **Rapid recovery—** The capacity to get things back to normal as quickly as possible after a disaster. Carefully drafted contingency plans, competent emergency operations, and the means to get the right people and resources to the right places are crucial.[17] |
| **At All Times** | **Adaptability—** The means to absorb new lessons that can be drawn from a catastrophe. It involves revising plans, modifying procedures, and introducing new tools and technologies needed to improve robustness, resourcefulness, and recovery capabilities before the next crisis. |

[17] "Rapid" recovery as used by the SIRTF does not mean rapid recovery to the pre-crisis operational level but to the New Normal.

### 2.1.6 Understanding the New Normal

North America's bulk power system is one of the most reliable in the world. BPS owners and operators consistently demonstrate their ability to respond to emergencies and restore service under the most challenging and adverse circumstances.

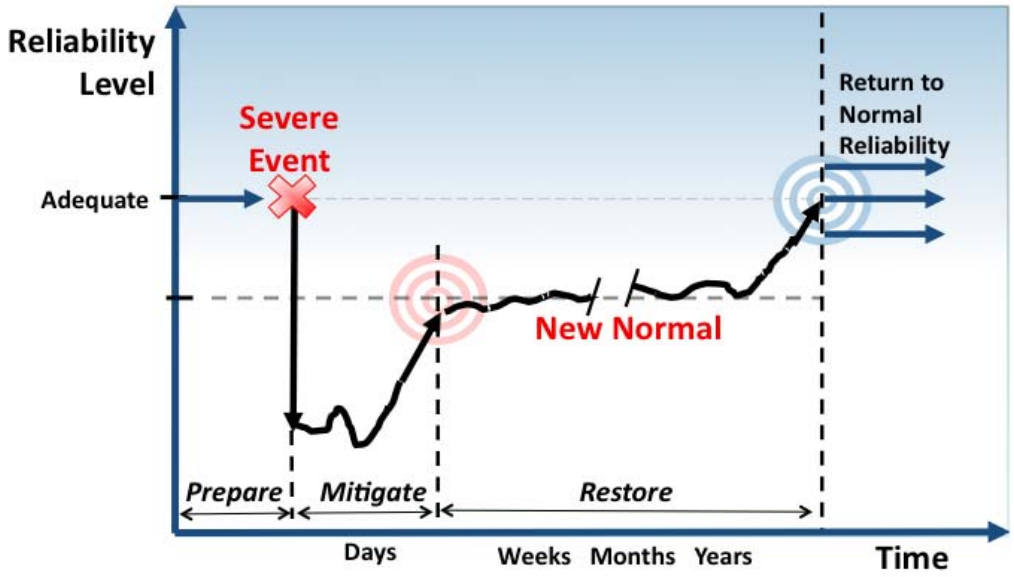
**Emergency Restoration**

The entities that operate North America's bulk power system are well practiced in preparing for and responding to emergencies. North America experiences far more severe weather events such as hurricanes, tornadoes, and ice storms than any other continent. This challenge will continue, as extreme weather events appear to be increasing in both frequency and intensity.

The electricity industry makes extensive use of emergency and business continuity planning, risk modeling, supply chain management, accountable organizational structures, emergency exercises, tabletop drills, operator training, safety procedures, redundant and backup systems, mutual assistance, and effective operational communications protocols.

While this industry-wide capability has proven effective in responding to the "normal" emergencies entities face from time-to-time, it is unlikely to be sufficient through a Severe Event. The SIRTF uses the term "New Normal" to describe degraded planning and operating conditions unlike anything the industry has ever experienced in North America that could exist for months or years.

**Figure 2: Severe Event Phases**




| Table 2: Severe Event Phases | | |
|---|---|---|
| **Phase** | **Duration** | **Characteristics** |
| **Prepare** | At all times | Entities enhance existing and develop new emergency response capabilities. |
| **Mitigate** | Days | Entities implement plans to minimize the impact on BPS equipment and maximize electricity service to consumers. Resources such as reserve capacity, spare equipment, and personnel are inadequate to return the BPS to normal operation. |
| **Restore** | Weeks, months, possibly years. | There is a risk that further Severe Events may occur. Resources such as personnel, spare equipment, and manufacturing capacity become increasingly limited. Other critical infrastructures are affected, reducing communications services and the availability of water, food, fuel, medical care, fire and police response. Over time, consumer load patterns change as people re-locate or implement their own energy solutions. |
| **Return to Normal Reliability** | Months, possibly years. | Reliability may not return to pre-event levels. Lessons-learned from the event may eventually increase reliability in some areas as the BPS is reinforced, or decrease in other areas where consequences of the event continue to impose operational limitations. |

### 2.1.7 New Normal Challenges

The following describes some of the challenges that would need to be managed through the weeks and months of New Normal operation. This is not an exhaustive list and is intended to illustrate conditions that owners and operators have not yet experienced and may have difficulty imagining.

- Although power is reliably restored to some consumers, planned and unplanned rotating blackouts disrupt service without warning as system operators manage BPS reliability with limited generation and transmission resources and unfamiliar operating conditions.
- Equipment damage and resource limitations force the BPS to be operated as a number of electrically disconnected islands, reducing the stability and reliability inherent in the large interconnected BPS.
- Other critical infrastructures are affected by electricity disruptions. For example, gasoline and diesel fuel shortages will occur as oil refineries take several days or longer to recover from each electricity service disruption.
- System operators need to dispatch generation and operate the transmission system manually using verbal direction that increases the likelihood of human error. Sporadic or limited electronic communications mean system operators need to rely on hardcopy documents that are less frequently updated.
- As a result of reduced generation and transmission resources and uncertain operating conditions, the BPS is operated with reduced efficiency and requires a larger margin of operating reserve, further aggravating the shortage of generation.
- Consumers experience large fluctuations in voltage and frequency that may trip sensitive electronic equipment.
- System protection devices configured for normal operation may be too restrictive for the voltage, current, and frequency variations inherent in a degraded operating state and would need to be adjusted to reflect these different operating conditions.
- Disrupted or unreliable automated trading or tagging systems limit the ability of balancing authorities and reliability coordinators to schedule and manage electricity flows between balancing areas.
- Extreme workload pressures on system operators, engineers, and other personnel limit the ability to meet certain standards requirements that do not compromise safe and reliable operations.

### 2.1.8 The Applicability of NERC Standards During a Severe Event

By definition, a Severe Event will present enormous challenges to electricity entities as they strive to restore and maintain reliable operations under rapidly changing circumstances never before experienced. It will not be possible to meet all electricity consumers' demands for early service restoration, as entities prioritize their work with limited human and material resources.

The SIRTF discussed the applicability of the NERC[18] standards under these circumstances, and whether entities should be exempt from possible compliance actions[19] through a Severe Event. The SIRTF reviewed the NERC standards and concluded that the vast majority of the standards support safe and reliable operation that would be equally applicable during a Severe Event, as they would during normal operation. While it is conceivable that an entity may decide to violate a certain standard in order to accelerate broader restoration objectives, it would be impossible to predict these circumstances in advance of any event, let alone a Severe Event.

Some of the NERC standards are administrative in nature and require, for example, that entities perform periodic documentation reviews in order to demonstrate compliance with the standards. Clearly, these activities would not be considered a high priority during a Severe Event. While there may be some merit in identifying these "administrative" standards as not applicable during a Severe Event, on balance, the SIRTF felt any discussion of standards and compliance during an event may be more of a distraction for entities, rather than help them remain focused on making the right operational decisions. Furthermore, as NERC's standards are evolving, and efforts are being made for all standards to become more performance and outcome-based. Over time, this will reduce or eliminate standards that are administrative in nature.

On balance, the SIRTF concluded that entities do not need guidance on the applicability of standards during a Severe Event. Although a Severe Event may put entities in a position where they cannot comply with all standards, entities are in the best position to "do the right thing" for reliability and public safety, and self-report any violation of NERC standards as time and circumstances permit.

[18] Ref. NERC Standards, http://www.nerc.com/page.php?cid=1|7

[19] NERC has the legal authority to enforce compliance with NERC Reliability Standards, which it achieves through a rigorous program of monitoring, audits and investigations, and the imposition of financial penalties and other enforcement actions for non-compliance.

# 3.0 Operations

This section identifies the challenges associated with operating the BPS following a Severe Event. Many aspects of operations in the New Normal are not entirely different from what entities have experienced to date but will be much more challenging for a number of reasons. For example, island operation in itself is nothing new – the North American grid is operated in four large islands known as the Interconnections. The challenge in operating islands following a Severe Event scenario is that the islands will be much smaller, more numerous, may comprise areas that fall under the authority of several different operating entities, and last for significantly longer periods of time (weeks, months or years) than previously experienced. Load shedding activities are also likely to be similar to, and very likely based upon, existing load shedding and rotating blackout plans required to respond to EEA-3 conditions (interruption of firm load). However, experience with implementing load shedding plans has been limited to relatively short periods of time – a few hours or at most a day or two. In contrast, under Severe Event conditions, rotating blackouts may need to be implemented for an extended period of time and for significantly longer rotation intervals.

Following a Severe Event on the BPS entities should expect that it will not be possible to fully restore the BPS to pre-event conditions and the system will be significantly degraded. In order to operate the BPS it will likely be necessary to operate in multiple electrical islands[20], and use emergency criteria, rotating blackouts, and a number of independent control actions[21] to maintain the supply and demand balance and manage frequency and voltage. Rotating blackouts help manage the supply and demand balance by rotating supply to different blocks of load, typically on a geographic basis, on a defined schedule or timeline.

The operation of these electrical islands may need to be performed by entities that are not normally responsible for system operator[22] functions such as Distribution Providers. As a result, these entities could become the system operator until such time as control is returned to the Balancing Authority or Transmission Operator for the balancing area. Following a Severe Event, it is not possible to predict what islands will be formed and this is further complicated when these island boundaries cross the balancing areas that are very familiar during normal operation. In fact, this occurred following the August 14, 2003 blackout that affected large portions of the Midwest and Northeast United States and Ontario (see sidebar).

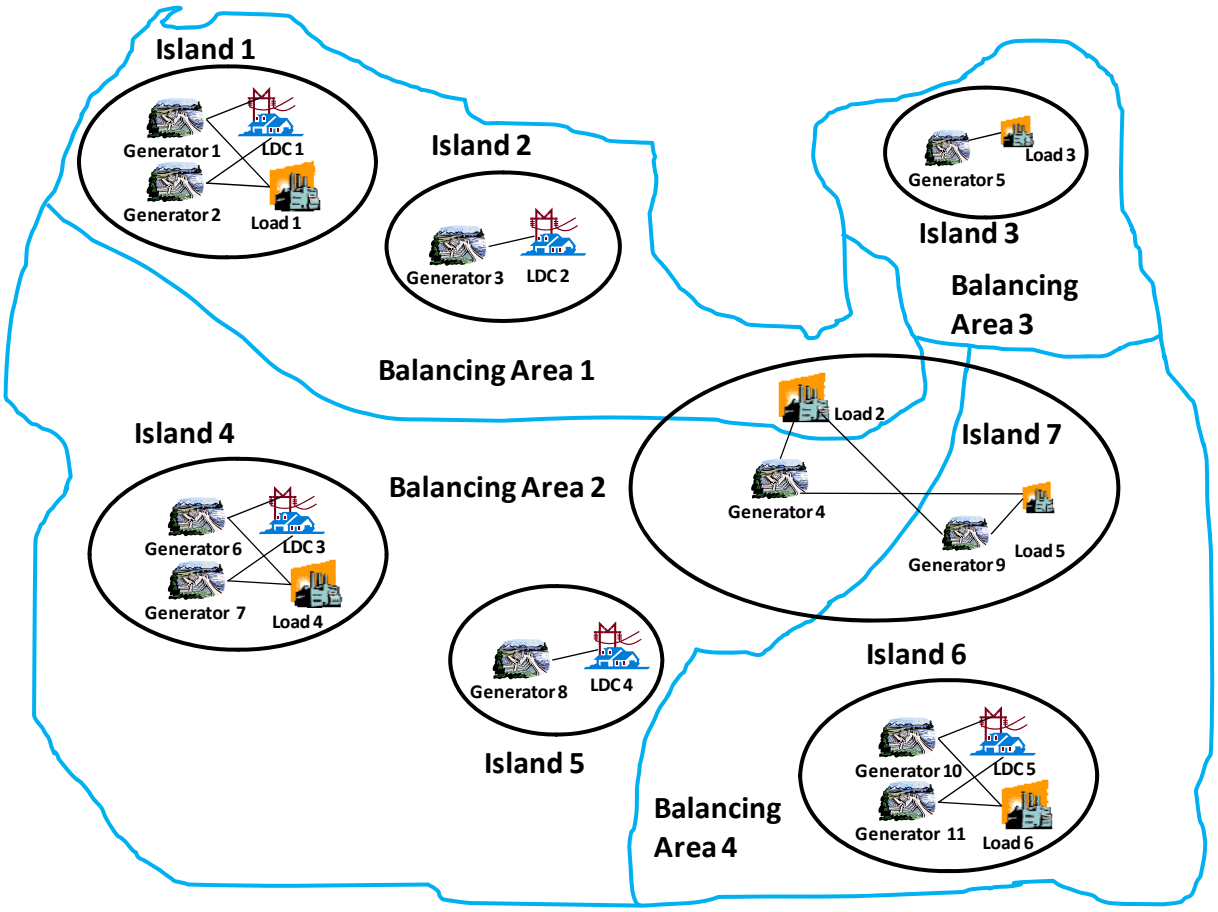
### Islanding Experience from the 2003 Northeast Blackout

Ontario's Beck and Saunders hydroelectric stations, along with some Ontario load, the New York Power Authority's Niagara and St. Lawrence hydroelectric stations and 765 kV AC interconnection with Quebec, remained connected to the western New York system, supplying load in upstate New York immediately following the event.

[20] Islanding is the complete separation of a portion of the power system from the remaining interconnected system following a system disturbance. Islands can be comprised of generation sources, transmission elements, distribution elements and loads.
[21] Independent actions are those operating actions required to enable power system restoration without prior communication to the Reliability Coordinator for approval.
[22] A System Operator is anyone who performs the system operator function as defined in NERC's Glossary of Terms.

The following diagram illustrates a likely scenario following a Severe Event. The BPS may form islands that do not respect traditional operator boundaries. While many islands depicted are within a single Balancing Authority (BA) Area, Island 7 is shown to exist in three distinct Balancing Areas.

**Figure 3: Islanded Operation**




The following sections provide more details around these challenges and the need for delegated authority and independent actions.

### Assumptions

This section assumes that a substantial number of supply resources are unavailable for an extended period of time and as much as or more than 50% of total instantaneous demand cannot be served in the islands. The cause(s) for this inability may vary significantly and are not limited to a lack of generation resources. The situation may be extremely widespread or it could be limited to specific areas within a single balancing area. At least initially, communication and control is impaired such that at least a portion of switching will need manual operations by field personnel.

## 3.1 Immediate Automatic Response

Immediately following the Severe Event, islands are likely to form as transmission lines between areas of the system trip. Automatic under-frequency load shedding and generator tripping may also occur as protective relays react to the transient voltages, frequency and power flows caused by the separation. Islands with small amounts of generation and load have less inertia and as such experience larger frequency swings, are harder to control, and are more likely to collapse from subsequent generation loss than are the existing four Interconnections.

Also, many of today's loads are frequency or voltage sensitive or both (such as computers, industrial control systems, other electronic devices) and may trip off-line as a result of these swings. The challenge with frequency or voltage sensitive load loss is that it will come back on the system once electrical parameters are within the prescribed range. Also this can be further complicated with the increase in automatic schemes within the distribution system for "self healing" (smart grids). This uncoordinated load restoration possibly increases the risk of island collapse.

### Recommendations

Entities should develop policies on how to treat smart grid components and frequency or voltage sensitive loads in islanding situations. The appropriate management of these components will increase situational awareness.

## 3.2 Operational Authority

Following the immediate, automatic system response, it is critical to determine the extent of the islands and which entity(s) are in "control" of the surviving islands. This determination would likely be made by the Transmission Operators (TOP). To be in control of an island an entity needs to have the ability and decision making authority to monitor and control the assets (generation, transmission and load) within the island's boundaries. Decisions may include the need to shed load, dispatch generation, put equipment in service, etc. Although the Reliability Coordinator maintains overall responsibility of the BPS, including the synchronization[23] of the islands, it may not have sufficient monitoring and communication to direct the operation of each island. With limited or no communication it is important that each of the entities know what independent actions they should take on loss of BPS supplied power.

### Recommendations

- Reliability Coordinators and Balancing Authorities should consider developing loss of communications and delegation protocols for responsible entities in their footprint and

[23]Synchronization is the closing of a circuit breaker between two electrically disconnected, energized parts of the power system. When synchronizing islands it is crucial to match voltages on both sides of the circuit breaker before closing. If this matching or "synchronizing" process is not done correctly, a power system disturbance will result and equipment (including generators) can be damaged. In order to synchronize properly, three different aspects of the voltage across the circuit breaker must be closely monitored. The three aspects of the voltage are called the synchronizing variables and are:
1. The voltage magnitudes
2. The frequency of the voltages
3. The phase angle difference between the voltages

with adjacent Reliability Coordinators and BA to allow seamless transfer to the responsible entity during loss of communication or monitoring scenarios or when islands cross jurisdictions.

- Establish and practice through simulation or tabletop exercises the independent actions that entities are expected to take upon loss of BPS supplied power. This might include:
  - TOP, Local Distribution Companies and directly connected wholesale customers opening all de-energized breakers under their operational control.
  - Generator Operators (GO) opening all de-energized unit and switchyard circuit breakers under their direct operational control, and beginning blackstart procedures for certified blackstart facilities.
  - GO securing station service with any available generation units in accordance with local instructions and agreements. This may include restarting hydroelectric generation units to run them at speed-no-load by closing the unit breaker (using synch bypass or synchronizing to other units).
  - For generation facilities with the capability to energize-out a portion of the BPS, GO would stabilize units and prepare them to energize transmission circuits as directed by the TOP.

    **Note**: It is important to establish the bounds for such independent actions to ensure that stability and reliability are not jeopardized.

| **Key Recommendation #1 \|** Operations |
|---|
| Consider which entities would take the independent actions and the tools needed to stabilize islands when communications capability is severely disrupted or unavailable. |

## 3.3 Initial Operator Response

Following the immediate, automatic response the next priority is to take operating control actions to stabilize any islands of generation and load that remain.

### Recommendations for System Operators

In order to stabilize the island the System Operator should:

- Determine the extent of the island (i.e., its electrical boundaries) and monitor frequency.
- Determine if the energy management system is communicating with the power plant control systems. If so, then setting Automatic Generation Control (AGC) to flat frequency control is desirable to allow a faster response to frequency deviations. This may not be desirable if telemetered tie-lines to adjacent systems are part of the island.
- In the absence of AGC, determine which generating units can have their droop curves adjusted to operate as the 'driver' unit in isochronous mode. It may be appropriate to spread this control over a number of units and set the unit's basepoint to the mid range of its operation.

- Once the size of the island increases consider if and when it is appropriate to restore the droop setting on the 'driver' unit.
- Manage the load-generation balance by dispatching available generation and by using load shedding as necessary. Operators must also recognize the difficulty in solving for Area Control Error (ACE) with limited telemetry.

### Recommendations for Reliability Coordinators

In addition to the above System Operator actions, the Reliability Coordinator may be in a position to perform some high level coordination tasks to facilitate a long-term islanded operation, including:

- Generator fuel supply tracking, scheduling and prioritization[24].
- Providing situation assessments (e.g., status of nuclear plants) and future prognoses to stakeholders including government, the media, and the general public.
- Assisting system operators to operate their islands within the context of the situation. The Reliability Coordinator may have a wider area view of the BPS and be able to coordinate operation and restoration activities across the various islands.
- Document and keep current the voice communications technologies and procedures available to communicate with other entities. Other entities could contact their Reliability Coordinator to determine alternate means to communicate.

### Recommendations for Power Plant Operators

Rapidly changing frequency outside normal bounds is likely an indication that the plant has formed an island with some load on the system. As noted above, the operation of the island may need to be performed by entities that are not normally responsible for System Operator functions, so that the plant operator may well communicate with a different entity than its normal system operator (e.g., BA, TOP). As a result of island formation, power plant operators should examine their plant outputs and consider doing the following:

### MW Output

- For AGC plants, power plant operators should determine if the energy management system is communicating with the power plant control system and leave any units on AGC.
- If no longer receiving signals, place units in manual and try to contact the System Operator and maintain unit output.
- For all other units, follow protocols for loss of communication and await further instruction from the System Operator.

[24] In some jurisdictions, for example those within competitive electricity markets for generation, the Reliability Coordinator has no role in tracking, planning or scheduling generator fuel supplies.

### Frequency

- Maintain output and attempt to contact the System Operator.
- Use the NERC Y2K Constant Frequency Operations Guide[25] to inform operational strategy in the event of communication loss.
- Make all available units ready for operation.
- If units trip, stabilize them and prepare to resynchronize following direction from the System Operator.
- Secure station service.

### Voltage

- Maintain Automatic Voltage Regulation (AVR) on automatic.
- When AVR is unavailable, minimize changes to MVAR output unless the plant is at risk.
- As directed by the System Operator, adjust power system stabilizer.

## 3.4 Island Stability

Large interconnected power grids are inherently stable because they have many sources of governor-controlled generation and relatively predictable load patterns. Conversely, small islands are 'high gain' systems where relatively small changes in generation or load can cause large changes in power system parameters such as voltage and frequency which may cause equipment to trip on existing protection settings. Although this action may impede restoration, these settings are critical to ensure that critical assets essential to restoring the BPS are not damaged. Also, many of the mechanisms and criteria that dictate how the BPS is managed may be unavailable or require significant rethinking.

System Operators should consider the following to build and maintain stable islands.

### Load

- Use distribution load controlled by SCADA to rapidly restore initial load, as time considerations may prohibit local manual operation.
- Maintaining the load-generation balance will require that System Operators anticipate the changing load pattern over time. This ability to forecast primary demand without historical data will be limited by a lack of detailed knowledge of the load in a portion of the normal balancing area. Although the peak load that can be served in the island is limited by available generation, the System Operator will need to understand the load pattern to manage frequency deviations as load picks up and drops off throughout the day. In addition, load levels in the island will likely be significantly lower than pre-event levels as industrial and commercial loads take time to recover following the Severe

[25] Ref. NERC Constant Frequency Operations Guide, https://www.frcc.com/handbook/Shared Documents/COM - Communications/Constant Frequency Operations Guide 100208.pdf

Event and resume some level of operation. The load will grow over time as operations resume but be limited by available generation.

- Prepare to limit restoring loads that are highly variable (e.g., smelter or arc furnace loads).
- Local field personnel who are familiar with the characteristics of loads at the distribution level will be critical to the development of a workable plan to anticipate and respond to changing conditions as the New Normal evolves.

### Generation

- Maintaining the load-generation balance requires that the capability and limitations of the various generation sources in the island are known, and mechanisms are in-place to dispatch them. Market mechanisms, schedules, and automatic generation control are likely to be unavailable or impaired.
- Governor response of the surviving units may be limited or may not be available. Also, in the absence of AGC, generators that can operate in isochronous mode become extremely important to maintain system frequency. Therefore the location and availability of generators that can operate in isochronous mode needs to be known to allow stable island operations. BA's should consider identifying the governor responses of generators within their balancing area and those that can operate in isochronous mode so this can be shared appropriately following a Severe Event.
- Variable generation, such as wind and solar, require special consideration which may require these generation sources be limited if they are in relatively small islands.
- Generation may be limited due to regulatory requirements or license conditions that are appropriate for normal operation but may need to be revised under New Normal conditions.
- Generators that remain off-line for extended periods of time require BPS-supplied power or backup generation to support station service, further limiting the generation resources available to serve other loads.

### Operating Reliability

Adequate operating reliability must be re-examined in the context of an island – normal operating reserve and system operating limits may no longer be appropriate.

- It is important to understand the limitations imposed by large voltage angle differences[26] and synch-check relays when reconnecting generation

**The Importance of Phase Angle Requirements**

During the Italian blackout of 2003, auto-reclosers failed to restore key inter-tie lines due to the large voltage angle across them – about 42 degrees. During the 2003 Northeast Blackout, synch check relays hindered system restoration.

[26] UCTE, "Final Report of the Investigation Committee on the 28 September 2003 Blackout in Italy," ed, 2004 and NERC, "Final Report on the August 14, 2003 Blackout in the United States and Canada," ed, 2004.

to the BPS. In order to protect nearby generators from high electromechanical transient stresses that occur during the switching of network elements, through studies, consider increasing the allowed maximum angle to accelerate or enable the restoration process or to allow reclosing.

- Adequate operating reliability must be re-examined in the context of an island. Normal operating reserve and System Operating limits may no longer make sense when all available generation needs to be on-line to serve as much load as possible. Manual and automatic load shedding may become the main source of operating reserve.
- The System Operator should consider how they might optimize operating reserve while operating is islands.

| **Key Recommendation #2 \|** Operations |
|---|
| Consider how operating reserve would be managed during islanded operation and frequent periods of insufficient supply to meet demand. |

## 3.5 Load Shedding

In the early stages of islanded operation, System Operators need to quickly determine their energy and capacity situation. During this time, they are likely to manage the load-generation balance using load shedding. Load shedding plans need to consider the priority or importance of loads such as critical power system loads and other dependent critical infrastructures such as telecommunications. System Operators must also ensure that sufficient load remains available for automatic underfrequency load shedding (UFLS) to help protect the island from collapse. It is assumed that UFLS set points will not be adjusted initially following a Severe Event, as these levels are still required to arrest frequency decay. However, they may be examined periodically during the New Normal timeframe. This is discussed more thoroughly in the *Protection and Control* section of this report. As restoration progresses, system operators will be challenged to forecast anticipated load patterns for numerous smaller load pockets contained within each electrical island.

System Operators must also be aware of the different load types in the islands, particularly those prone to large swings in consumption such as electric arc furnaces and large motors. If not already shut down, these consumer loads may need to be severely curtailed until the island becomes sufficiently robust to cope with the load variability. Similarly, System Operators will need to know the maximum load block they can restore in an island as additional generation becomes available.

### Recommendations:

- It is important to define, up front, what are considered "critical"[27] and "priority" loads for system restoration and managing load shedding. These terms are defined in the table below. Ensure that critical power system loads and other critical infrastructure loads such as certain telecommunications centers are excluded from load shedding plans.

[27] The term "critical load" is different than the term Critical Asset as defined in the NERC Standard CIP-002.

- Conversely, consider loads that might be non-essential (e.g., street lighting, billboards) which might be without power until full restoration (to the pre-event levels) is achieved.

| Table 3: Critical and Priority Loads | |
|---|---|
| **Critical Loads** | **Priority Loads** |
| Critical loads are BPS loads essential to perform restoration and maintain reliability. In some cases, these loads are within distribution systems. During restoration, other loads may be designated as critical loads if they are essential to support restoration (e.g., load required to manage voltage). Examples of critical loads include:<br>• Station service at control centers, transmission substations and generating stations<br>• Power system communications facilities<br>• Protective relays and schemes<br>• Monitoring and control systems | Priority loads are important consumer loads that need to be restored promptly to mitigate the impact on public health and safety, the environment, or the economy. Priority loads connected to the high voltage transmission system or to the distribution system are often excluded from load shedding schedules. Some examples of priority loads include:<br>• Oil refineries and pipelines<br>• Telecommunications centers<br>• Hospitals<br>• Water treatment and sewage plants<br>• Key military facilities. |

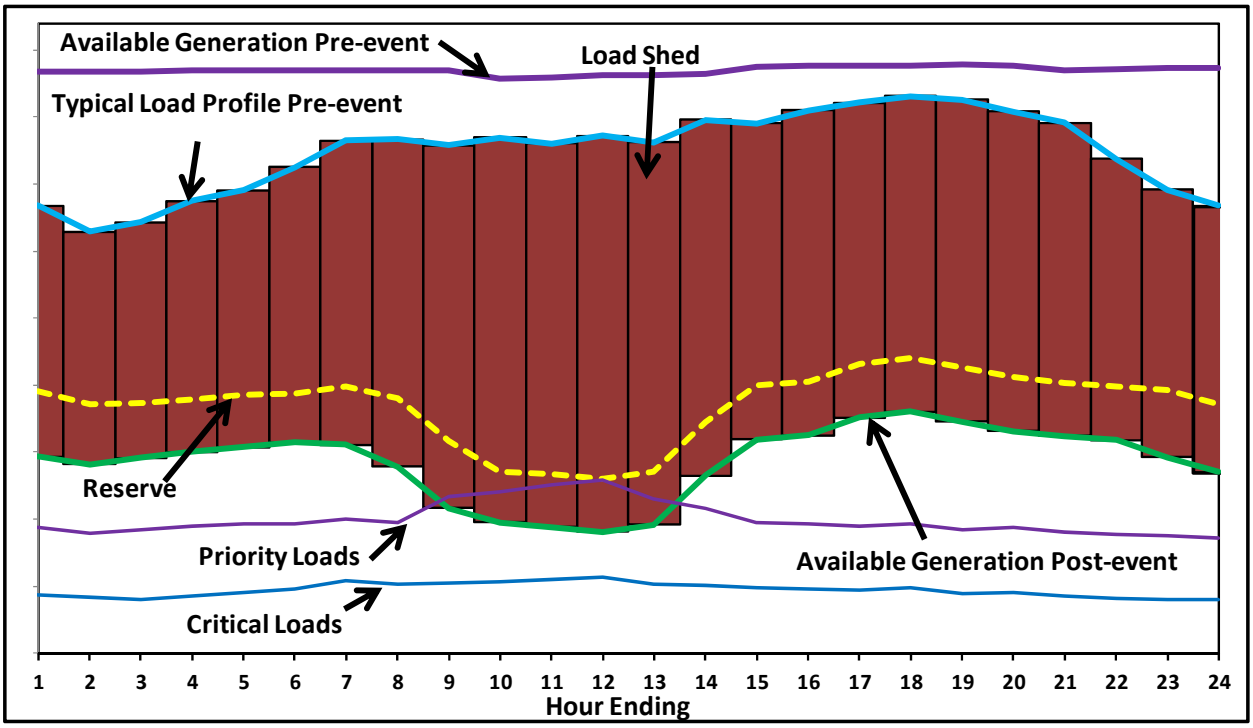
| **Key Recommendation #3 \|** Operations |
|---|
| Consider ways to adopt and apply the terms “critical load” and “priority load” across all BPS entities to improve consistent use during a Severe Event. |

- In the event of sustained rotational load shedding (rotating blackouts) communication becomes a key factor to ensure that affected areas understand what power supply they will have, at what time and for how long. Due to the potential impacts on public health and safety, these communications need to be carefully considered and coordinated with local distribution companies, local law enforcement agencies, emergency responders and government officials. Although the specifics of this communication cannot be established ahead of time, entities should develop a communication strategy in consultation with key stakeholders.
- Develop mechanisms to predict new load patterns in each island.
- Identify loads characterized by large swings in demand. Detailed knowledge of the types of loads in each island will allow the system operator to appropriately manage them to maintain island operating reliability.

- Develop through system studies and industry experience, rules of thumb to help the operators determine the maximum size of a block of load that can be safely added to an island, based on the available MVA of synchronized generation.
- Since it is impossible to predict the extent of islanding formation following a Severe Event, it may not be practical to share operational information ahead of time. It is important therefore that information-sharing strategies are established in preparation for such events to expedite this information dissemination and address any confidentiality concerns.

The ability to serve load within islands is expected to be limited following Severe Events. The blue line in the figure below shows a typical load profile for an area under normal conditions. The green line represents the load that can be served following a Severe Event, the difference between the red and green lines is the total amount of load that will not be served, and the difference between the green line and the dashed yellow line represents generation or load shed reserved for contingencies.

**Figure 4: Inability to Serve All Load During Restoration**




## 3.6 Generation Dispatch and Automatic Generation Control (AGC)

Following the formation of islands, it may not be viable to have a centralized dispatch function based on bids and offers, so system operators will need to have an alternate means to dispatch. Similarly, AGC may not be available due to limitations on the number of islands it can control or loss of frequency or tie-line measurement. Even in the absence of AGC capability, the System Operator must have a reliable frequency measurement in the island. Also, one or more generators must be capable of isochronous operation (i.e., zero droop) to restore frequency following changes in load. System Operators need to have information on the capability and limitations of the various generation types in the island, including those that are energy limited or may have fuel supply or other operational restrictions.

### Recommendations:

- Develop alternate dispatch mechanisms, including communication protocols.
- Investigate the viability of installing more frequency measuring devices to increase signal redundancy or using other sensing devices such as phasor measurement units.
  - Alternatively, coordinate with other infrastructures that may be monitoring frequency from distributed devices and develop the means to share this information.
- Investigate using multiple sources for tie-line flow measurement (e.g., Inter-Control Center Communication Protocol from neighboring entities, redundant metering capability).
- Consider the viability of using AGC to simultaneously control multiple islands.

- Consider mechanisms that allow the transfer of pockets of load and associated generation near a tie line to an adjacent BA for operation within the electrical borders of that BA. Generation within the pocket could be dispatched via voice communications at a relatively fixed level while the adjacent BA provides load following capability via the tie lines.
- Determine which generators can change their droop curves – modify governors as necessary.
- Plan that nuclear generation may be off-line, and develop contingency plans in conjunction with the generator owners and operators to help ensure that BPS-supplied power is available.
- Document generator capabilities and limitations in an area so this information can be readily shared should the dispatch function be delegated to an entity that does not normally perform this role.
- Information sharing protocols should be developed ahead of time with organizations that are most likely to need this type of information following a Severe Event. These protocols may need non-disclosure agreements.

| **Key Recommendation #4 \|** Operations |
|---|
| Consider alternate means to dispatch generation if normal automated systems, including automatic generation control, are unavailable. |

## 3.7 Variable Generation

Variable generation (Wind & Solar) is becoming a more prevalent form of generation, and has unique characteristics that must be considered during restoration. Some (generally smaller) wind turbines are not truly dispatchable, but have variable output as a function of wind speed. For those wind generators connected to the distribution system, operators need to be aware of their impact but may not have real-time system monitoring of their output.

Normally, automatic controls connect and disconnect banks of wind generation according to the wind speed and any maximum cap set by the wind generator operator. This variability of output is not a concern when the system is in a normal state, but can be problematic during a restoration, particularly when trying to stabilize or synchronize islands.

### Recommendations:

- System operators should consider developing policies on how they treat variable generation (i.e., wind, solar) during island operation. These policies could address such matters as:
  - Treatment variable generation when their varying outputs cause unacceptable voltage or frequency deviations.
  - The impact of disconnecting all wind and solar generation at once either through tripping or directed actions. This may cause the island to collapse if the variable generation exceeds a specific percentage of the island's generation capacity.

- Disconnecting wind generation in banks and the need to compensate with other generation or through load shedding to maintain frequency.
- In blacked-out areas, consider disconnecting these resources and leaving them out of service until the latter stages of restoration.
- Consider connecting variable generation to large-scale storage devices radially to optimize variable generation output.

| **Key Recommendation #5 \|** Operations |
|---|
| Consider if or how variable generation would be dispatched through restoration and islanded operation. |

## 3.8 Training

Consider enhancing existing training for system operators and field personnel to address the challenges of a Severe Event.

- Manual synchronization of islands
- Islanded operations with local control area operators assuming control of certain islands
- Communication tabletop exercises to verify and train on new coordination and communication protocols between various entities including a loss of, or significantly degraded, communications.
- Implementing rotating blackouts for extended periods of time.
- Identify, accommodate, and implement changes to priority loads.

| **Key Recommendation #6 \|** Operations |
|---|
| Consider enhancing regular restoration drills and exercises to train staff on communication protocols and independent control actions in the event of loss of or degraded telecommunications. |

| **Key Recommendation #7 \|** Operations |
|---|
| Consider using more extreme exercise scenarios that involve simulated rotating blackouts and islanded operations on a larger scale and for extended periods of time. |

# 4.0 Monitoring the Bulk Power System

The 2003 Blackout Report[28] emphasized the importance for system operators to maintain situational awareness of the BPS. In the case of Reliability Coordinators, there is also the need to maintain situational awareness over a wide area that extends beyond their immediate operating zone. Due to the interconnected nature of the BPS, system operators also rely on the system conditions and data of their interconnected neighbors.

**August 2003 Northeast Blackout – Recommendation**

***"#22. Evaluate and adopt better real-time tools for operators and reliability coordinators."***

Since the 2003 Blackout the industry has continued to evaluate and adopt better tools that support real-time operation. System operators and Reliability Coordinators have enhanced their tools to provide decision support and situational awareness with greater granularity, accuracy, and a wider area view. In addition, NERC's reliability standards require minimal acceptable levels of this capability for system operators. Entities continue to explore and leverage state of the art technologies such as phasor measurement units and other new methods to monitor, anticipate, and respond to real-time thermal, voltage, and stability challenges.

To achieve and maintain situational awareness the electricity sector has over the past decades developed increasingly sophisticated tools consisting of metering points, communications networks and sophisticated software to monitor the BPS more frequently, accurately, and precisely than ever before. Within each entity, these tools typically monitor thousands of data points every few seconds at transmission sub-stations, lines, and generators.

While these tools are designed to be robust with availability rates of at least 99%, they do occasionally fail. Therefore, every operating entity has backup, call-out, and response plans to rapidly diagnose and address problems. Yet as strong as these regularly exercised plans are, a Severe Event could create such wide spread degradation of these tools or data that many operators throughout the interconnections may at best see only a portion of the BPS required to operate the system reliably.

System operators need to ensure that they have sufficient visibility and control in order to sustain a stable island. Inability to control the various parameters can lead to instability of the island and result in equipment damage. In this section, options are provided to continue to monitor the operation of the BPS, in spite of degraded system monitoring tools such as:

- **Energy Management System (EMS)** – provides system operators with data and analysis to monitor and operate the transmission system. An EMS includes several important functions.
  - The "model" of the EMS provides a mathematical representation of the BPS to enable contingency analysis and other monitoring functions.

[28] US-Canada Joint Power Outage Task Force https://reports.energy.gov/BlackoutFinal-Web.pdf

  - The State Estimator uses the model to calculate data points that are not physically metered and can help validate data or estimate missing data in the event of metering failures.
  - Security Analysis software provides sophisticated "What If" contingency analysis so operators can be prepared to take prompt action if BPS elements such as generating units or transmission lines become unavailable.
  - Automatic Generation Control (AGC) to automatically raise or lower the output of certain generators to dynamically balance total generation output with consumer demand.
- **Generation Management System (GMS)** – provide power plant operators with data and analysis to monitor, control and operate multiple power plants to keep generation resources on schedule. GMS may also include AGC functions.

### Assumptions

This section assumes that the tools used to maintain BPS situational awareness are compromised or substantially degraded for an extended period of time. Telecommunications capabilities are also in a significantly degraded state. Entities must monitor and operate a BPS that is unfamiliar and likely in an unstudied state. Entities will need to communicate and share information both internal to its operating footprint and external to neighboring entities.

## 4.1 Generator Output

Either MW or MVar output data is unavailable from the energy management systems or is of questionable quality. System operators should consider the following:

### Recommendations

- Following an event, create communication schedules to have power plant operators report current and projected MW and MVar output for each unit.
- Develop block loading schedules so that Generator Operators understand in advance what actions will be taken depending on system conditions (e.g., frequency readings, time of day, interconnection point voltage schedules).
- System operators could define specific operating ranges for generators that could assist in verifying that operating directives are reasonable and authentic.
- Operating to such schedules might be difficult in the early stages of a Severe Event as the system may be less stable and operating with fewer resources. As a result, ranges may need to be larger to provide greater operating latitude, but as operating experience with the New Normal system is achieved operators might tighten these ranges.

## 4.2 Operating Limits

System operators must continually ensure they are operating equipment within established limits in order to avoid further damage to equipment and support reliability. Operating limits may need to be recalculated as configuration changes will alter system impedances and system flows will be radically different from normal operation. Operators will need to perform these recalculations periodically throughout the Severe Event. For each recalculation, affected entities will need to consider how close they should operate to the limit based on their understanding of the risk of the next contingency. If the risk is determined to be high, it may be better to operate further away from the limit but serve less load. If the risk is determined to be lower, it may be better to operate closer to the limit and serve more load.

### Recommendations

- **Hard Copy Reference Material** – Provide thermal limit ratings for each facility in hardcopy form. Periodically confirm these ratings with automated values when on-line calculations are available.
- **Standard Operating Procedures** – BPS entities change their facility ratings at particular triggers depending on system conditions. Some entities change their ratings seasonally, others have very granular temperature sets of ratings that are different for day and night operations. During a Severe Event, system operators could implement standard operating procedures for switching to different temperature sets at established times. This will help ensure that control actions are coordinated and both parties use the same limit at the same time and under the same conditions. However, these ideas would likely only be explored after the system has returned to a greater level of predictability. It is more likely that following a Severe Event the best recourse would be for operators to use conservative limits.
- **Conservative Limits** – System Operators could default to pre-studied conservative limits to provide additional robustness to the transmission system in order to absorb an anticipated threat. These conservative limits could represent N-2 or maximum credible contingencies and position the BPS in a more resilient mode of operation.
- **Revisit Design/Operating Assumptions** – Following an event, system operators may need to revisit the assumptions underpinning their limits (i.e., operating in a number of small islands will create far different flows on the system than during normal interconnected operation). Design assumptions that need to be reviewed include the type and amount of load, the interconnected/networked nature of the system, generation mix, and system transfers and flows.
    - The New Normal operating environment may require system operators to operate with far more risk of potentially damaging equipment and/or cascading islands. Redefining these operating assumptions may provide greater flexibility to serve more customers provided any short-term gains are balanced against potential long-term consequences.
    - Reassessment of operating limits may also be driven by physical damage or long-term unavailability of assets.

- If these changes in assumptions drive changes to limits, the operating entity should communicate these changes with its Reliability Coordinator and any interconnected neighbor.

| **Key Recommendation #8 \|** Monitoring the Bulk Power System |
| --- |
| Consider developing processes to quickly study island configurations and develop suitable operating limits. |

- **Operate to the Most Conservative Reading** – During normal operations, when either a limit or the monitored flows are in question, operators should always operate to the most conservative readings/limits. Entities should consider when this fundamental requirement might not be achievable in the New Normal. Example decision criteria might include:
  - Reconsider operating to the more conservative reading/limit when the result might create far greater social impact (e.g., inability to serve priority loads that have a clear impact on public safety).
  - What entities need to be consulted to understand possible consequences? Can emergency management organizations better help frame such decisions?
  - Safety of nuclear units may be put at greater risk if an operator were to default to the more conservative limit that would require switching a line providing BPS power out-of-service. Accepting the short-term risk of keeping the line in service, might be the more prudent and safe decision for the overall community.

## 4.3 Monitor Flows on BPS Facilities

Having system operators continually understand either the actual or modeled flows of tie lines and internal transmission facilities is essential in system operations (these readings are as critical as an altimeter is to a pilot). As such, an adversary could have either altered an EMS Model's representation of the topology of the system (altered which elements are modeled in service or out) or have changed the modeled flows and possible impacts (impacts to State Estimation and Security Analysis results).

### Recommendations

Consider operating without any state estimation, relying only on actual power system flows for weeks to months.

- Prior to an event, conduct studies with the EMS to understand the bare amount of data required to keep the current state estimation model and security analysis applications solving.
- Assess whether greater levels of load or generation aggregation could be used to reduce the amounts of required data.
- Consider if a simplified model with reduced granularity could be stored locally or on a separate portion of the Information Technology (IT) network. Consider if this model could be uploaded to the EMS and integrated with the state estimator and identify:

  - Subject matter experts needed
  - Time and effort required
  - Procedures needed to implement if subject matter experts are not available?
  - Testing and training
- Assess what conservative operating restrictions may be needed to mitigate the reduced accuracy of the simplified model (e.g., conservative limits for certain facilities).
- Create a prioritized list of the data points most critical to understanding the operating state of a given operating area (the canaries in the coal mine).
- Consider the need to reconfigure study models to reflect an extended period of islanded operation, and at what stage of the New Normal this would be undertaken.
- Consider the field personnel and communications capabilities needed to sustain 24x7 manual monitoring at critical data points. To enhance this capability, consider:
  - Training required to provide accurate monitoring and maintain safety
  - Developing procedures and reporting formats for each facility
  - Using security personnel for some monitoring duties
  - Communications equipment, facilities and methods
  - Pre-arranged reporting times
- If the Internet is available, consider using social media (e.g., Twitter feed) to facilitate reporting.

| **Key Recommendation #9\|** Monitoring the Bulk Power System |
|---|
| Consider developing processes to monitor BPS flows in the absence of reliable automated systems and communications. |

- **Use of Phasor Measurement Units** – Throughout the Eastern, Western and ERCOT interconnections, phasor measurement units (PMUs) are being installed to enhance the granularity of BPS data. PMUs provide system operators a paradigm shift in situational awareness. Rather than measuring the system every few seconds, PMUs can measure the system tens-of-times per second. As exciting as these emerging possibilities are for operations, what is intriguing from a resilience perspective is that many of the new applications using PMU data provide new opportunities compared with traditional EMS applications and data communication links.
  - System operators are currently field testing new PMU applications and considering how these may provide a completely independent source of data.
  - PMU applications could be driven by data collected at particular points via data concentrators, and may provide system operators with essential data using far fewer PMU readings.

  - As these PMU applications are developed to become full production operations applications, organizations may consider how to keep the PMU applications independent of EMS applications and support hardware. The end result may be that PMU applications might not only enhance current operational reliability but support reliability and resilience in a New Normal environment.

- **Use of FNET** – Research into island detection based upon the use of frequency disturbance recorders (FDRs) originally installed as part of the frequency monitoring network[29] (FNET) program developed at Virginia Tech is currently under way as part of the GridEye[30] program managed by the University of Tennessee and the Oak Ridge National Laboratory. The proposed project seeks to combine FDR data and offline analysis to provide a practical, low cost implementation of island boundary visualization based upon existing technology and real-time/historical data.

## 4.4 Loss of Control Centers – Both Primary and Backup

This section addresses concerns and issues that would result when there has been a loss of both the primary and backup control centers for a BA, TO, or Reliability Coordinator. Most likely the risk of losing both control centers is very remote. However, following the 2011 Fukushima disaster, the Chair of the Nuclear Regulatory Commission commented that if such a disaster had occurred in the U.S., the Commission would have directed evacuations within 50 miles of the impacted plant(s). How many operating entities have both of their control centers in the 50 mile radius of a single, if not multiple, nuclear plants? There is no panacea for the numerous problems that would be manifested in this scenario; however, there are a number of things that could be addressed before, during, and after such an event that would lessen its impact. Yet the following recommendations are not intended to encourage the building of tertiary (back-up to backup capability); however these ideas are shared to elicit consideration of the how to avoid or respond to the very remote possibility of losing both control centers.

### Recommendations

- When considering a new location for the primary or alternate control centers, consider building the new facility a distance from the other which would avoid common risks including natural and man-made concerns such as 1) earthquake fault zones, 2) hurricane or tornado zones, 3) evacuation radius for nuclear and chemical plants, 4) tsunami risks 5) volcano eruption zones 6) chemical spills from rail or highway accidents and manufacturers, or other risks. It is understood that the greater the distance between control centers the longer it would take to occupy the backup control center; as such there are inherent tradeoffs between the possibility of losing the ability of controlling a portion of the grid while the entity is occupying its backup control center.
- Consider developing arrangements with neighboring Balancing Authority, Transmission Operator, or Reliability Coordinator, [Power Plant or Market Dispatch Office] to share or use their control facilities.

[29] Ref. FNET, http://fnetpublic.utk.edu/
[30] Ref. Grid Eye, http://www.ornl.gov/sci/electricdelivery/pdfs/GridEye Fact Sheet.pdf

  - Share telemetry between entities
  - Use Inter-Control Center Communication Protocol from a third party
- Deploy multiple, diversely routed telemetry communications paths from selected critical remote terminal units to data concentration hubs which are not co-located with the control centers.
  - From each of those data concentration hubs, telemetry could be fed to both the primary and alternate control centers, or a third party with which there is a contract to share their control center/capabilities.
  - An EMS, SCADA, or mini SCADA[31] could either be located at or mobilized to a data concentration hub to allow limited emergency system control with the loss of both control centers.
  - As the industry continues to deploy and leverage Phasor Measuring Units (PMU's) within operations, entities may consider concentrating the PMU data at a tertiary site away from the primary and back-up control centers. Having the PMU concentrator and user interfaces might provide for a bare bones tertiary control center.
- During the time the entity is required to operate at a location other than the primary and backup control center, physical security would have to be maintained at the alternate site. The physical design should enable this to be accomplished quickly and easily. Contracts should be developed in advance for any needed security services.
- Consideration should be given to the logistics required for self-sustained operations, at an alternate site. This would involve sufficient office space for engineering, computer, and dispatch personnel, as well as, the supplies and storage for food and water for an extended period.
- Consider building operator-training simulators at a location independent of both the primary and back up control centers. Though the simulator will not have the complete capabilities of the primary control center or backup control center, if connected to particular data concentration hubs it may permit operators to control portions of the BPS within the parameters of the New Normal.
- Should entities consider having their Storm/Emergency Response centers at tertiary sites with some limited level of system control and information?
- Often control centers of large areas have many subordinate control centers. These subordinate control centers could range from being a local control of a large transmission owner to a small municipal operating entity. Regardless of size and particular monitoring capabilities, these subordinate entities could participate in drills where they must operate in the absence of direction and oversight. As such, if a large entity were to lose both its primary and backup control centers, efficient BPS operations

[31] A mini SCADA has less functionality and capacity than a primary SCADA, with fewer telemetry points and limited advanced applications, if any. It usually is capable of at least monitoring tie line flows with neighbors.

may have been impacted, but effective operations may still be maintained through a far more diverse group of operating entities. In order to achieve effectiveness, parties may need to consider the training and drills needed to create the confidence and capabilities to achieve reliability under this distributed model.

- If there is a warning of a possible attack or major system event, operating entities may want to consider staffing each of the sites where it has some operating capability. In the event that anyone or multiple sites are damaged the remaining facility may be able to take control, if only partially.
- From a cybersecurity perspective, both control centers could be significantly degraded if the primary and backup control centers are simultaneously exploited through the means by which entities keep the facilities synchronized. In an environment of heightened cyber threat, operating entities may consider not keeping these facilities synchronized and using different sets of cyber controls and hardware to ensure that both centers do not have common vulnerabilities to potential cyber threats.

| **Key Recommendation #10 \|** Monitoring the Bulk Power System |
| --- |
| Consider the simultaneous loss of primary and backup control centers and how essential functions will continue to be performed. |

# 5.0 Communications

The reliable operation of the BPS depends on a highly reliable communications infrastructure. North America's BPS has been described as the world's largest machine; generation resources, consumer load, field operations, and centralized controls are all separated by significant geographic distances and the actions of any single entity can significantly impact others. Although communication, both voice and data, is very important in normal operations, during a crisis situation it is absolutely critical[32].

During a Severe Event communications will be degraded to some extent, and entities may experience the complete loss of normal communications. Despite this, operating entities must strive to continue to monitor the system and direct operations at all times regardless of circumstances. This section discusses alternatives to address the challenges associated with degraded communications.

### Assumptions

This section assumes that communications is degraded as a result of a Severe Event for a number of reasons:

- Impact on communications infrastructure from one or more of the following:
  - Loss of BPS power supply to telecommunications facilities
  - Physical damage to telecommunications facilities
  - The user volume of communications exceeds the capacity of communications facilities, especially cellular and satellite telephone networks
- New and unfamiliar communications protocols that are not required during normal operation may need to be arranged with entities or individuals.
- Electricity market functions that depend on automated dispatch will be dramatically reduced or suspended, creating the need for manual operator control and direction.

[32] A cyber attack will pose particular risks to the systems used to operate the BPS. This is addressed by NERC Cyber Attack Task Force report, currently under development.

## 5.1 Communications Relationships

The need for reliable communications depends on the operating relationships between entities. The following table illustrates key working relationships and the types of communications most critical to BPS operations through a Severe Event:

**Table 4: Key Communications Relationships**

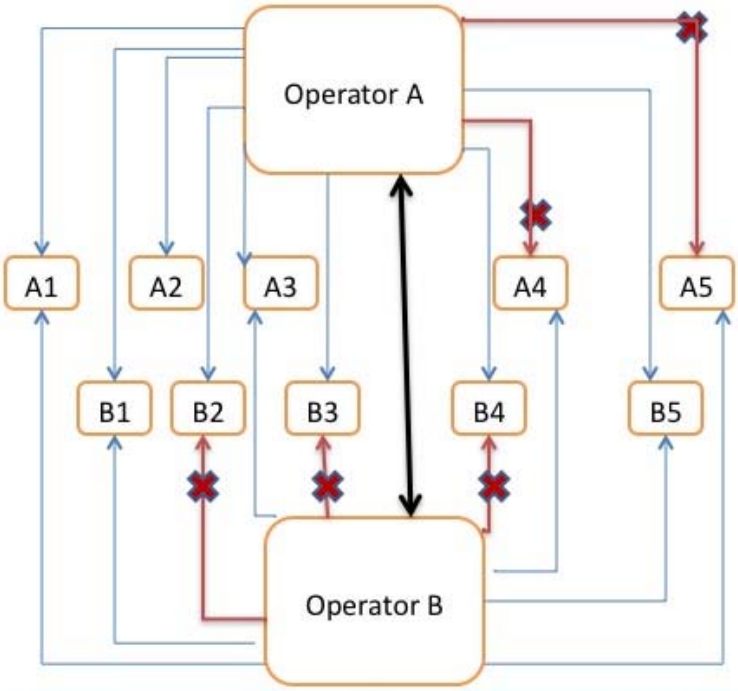
| Relationship | Key Communications |
|---|---|
| 1. Between field personnel, through the Distribution Provider and Transmission Operator, and the control center of the Transmission Operator | • Assess situation at remote facilities<br>• Manually read meters and equipment status indicators<br>• Operate equipment (e.g., opening and closing breakers) |
| 2. Between the Balancing Area and the Generator Operator within an island | • Determine generator status and schedule, including fuel and operating limitations<br>• Direct generation schedules (MW and Mvar)<br>• Monitor frequency<br>• Determine which unit could operate as the driver unit in isochronous mode |
| 3. Between the plant Generator Operator and its connected Transmission Operator | • Determine generator status, schedule, and constraints on unit output<br>• Determine transmission line and substation loadings<br>• Implement restoration sequence<br>• System configuration |
| 4. Between the generation/transmission operators and their suppliers of equipment and services | • Determine fuel, equipment, and other resource requirements<br>• Secure reliable delivery of essential fuel, equipment, and other resources |
| 5. Between the control centers of neighboring but not necessarily interconnected Transmission Owners, Transmission Operators, Balancing Authorities, and Reliability Coordinators | • Confirm generation and transmission status and limitations<br>• Methods of controlling generation to match load throughout the zone<br>• Decide plans to synchronize islands<br>• Identify opportunities to provide mutual assistance |
| 6. Between the Transmission Operator control centers and the Reliability Coordinator | • Discuss and coordinate restoration and operation options and strategy<br>• Confirm operating authorities |

| Table 4: Key Communications Relationships | |
|---|---|
| **Relationship** | **Key Communications** |
| 7. Communications with Government entities (e.g., local and state emergency operations centers) | • Assess situation<br>• Determine prognosis for restoration of service<br>• Identify needs and priorities<br>• Coordinate with other critical infrastructures<br>• Coordinate public communications (e.g., schedules for rotating blackouts)<br>• Identify safety and security needs and solutions<br>• Keep informed about status and manage expectations for service |
| 8. Between the consumer loads and the Distribution Service Provider | • Provide information regarding the nature of loads within the area such as priority loads, large or variable loads, issues related to cold load pickup<br>• Coordinate and communicate service restoration information and rotating blackout schedules<br>• Communicate restoration information and manage customer's expectations for service quality |

## 5.2 General Communications Recommendations

- The *Interdependencies with Other Critical Infrastructures* section of this report suggests ways to work with telecommunications service-providers to better understand interdependencies and mitigate the risks associated with BPS and telecommunications infrastructure disruptions.
- Consider co-locating BA and TO functions within the same work center in order to reduce communication requirements and assist with the synchronization complexity of restoration.
- When examining backup communications options, minimize the number of repeater hops to reduce the number of possible failure points. Configure satellite telephones so they operate point-to-point without the need for intermediate ground stations. Entities should be flexible and prepared to create a network that may include hops to other entities in their wider area through whom they can communicate as illustrated in the figure below.

**Figure 5: Alternate Communications Paths**




Operator A has communications with key facilities A1, A2, and A3 but does not have communications with A4 and A5. And Operator B cannot communicate with B2-B4. When Operator A confirmed it had communications with Operator B, it found Operator B could communicate with facilities A4 and A5. As such Operators A and B developed a communications relaying relationship. While Operator A is working to restore communications to all of its facilities , it is trying to assist Operator B with getting communications with facilities B2, B3, and B4.

- Entities should consider installing mobile radios compatible with those used by neighboring entities, and developing protocols to share assigned channels.
- When preparing for the Y2K transition period, many entities implemented satellite telephones and continue to rely on them in the event primary communications facilities are unavailable. Entities should consider assessing the extent to which satellite telephones can presently be used to coordinate operations between entities within each Interconnection.
- Identify personnel in advance who have communications skills, such as HAM radio or social networking media such as Facebook or Twitter. If the Internet continues to be available these methods could be very effective in communicating rapidly to the public at large.
- Consider backup generation, wind generation, and solar cells at communications sites to prolong the power supply to these resources. Note that sources of variable generation will require significant energy storage capability.

| **Key Recommendation #11 \|** Communications |
| --- |
| Consider installing renewable generation (e.g., wind, solar) or expanding fuel storage capabilities at critical BPS facilities to supplement standby generators. |

- Prepare plans for long-term fuel delivery to backup generation at entity-owned communications sites.
- If time permits before a degradation of communications, increase the utilization of system "All-Call" and the NERC Reliability Coordinator Information System (RCIS) to notify operating entities of increased operating activity and the need to coordinate major system activities.
- If primary communication links to remote terminal units are down but other communication lines are functioning, consider how an Operating Entity could leverage sub-station security communications capabilities (i.e., radios, fiber communications) to relay critical power system flows, without significantly jeopardizing these systems.
- Local emergency management services (e.g., police, fire, military) vehicle radios may provide both physical security and communications capabilities at critical sub-stations.
- Local HAM Radio chapters often have agreements with local emergency operations centers to provide communications in times of emergencies. Consider reaching out to these chapters[33] to integrate into business continuity planning and possibly drills and exercises.
- The military once had wire telephone communications gear. If available in local armories, consider how operating entities and the military could use such wired communications between critical operating nodes within a particular island (this option would require physically laying the wire and staffing switch boards).

| **Key Recommendation #12\|** Communications |
| --- |
| Consider alternate means to communicate when primary means of communication are completely unavailable for extended periods of time. |

[33] Radio Amateur Civil Emergency Service http://www.qsl.net/races/ and Amateur Radio Emergency Service http://www.arrl.org/ares

## 5.3 Communication Protocol Recommendations:

### Reporting Formats

- Know which are the critical data points are needed to assess the current operating state (review and refresh the protocols developed for Y2K to report critical operating data).
- If all sites are reporting during a single time period (or even staggered), prioritize which stations report first (e.g., by criticality of the information, alphabetical order, or other method). Structured and sequential communications will help manage communications volumes and delayed or missed calls.
- Develop a standardized reporting format so more information can be passed more effectively (i.e., Location, reading 1, reading 2, issues, possible opportunities, actions).
- If spreadsheets are used to record the data, consider if dedicated laptops are needed to consolidate the data, or if hardcopy forms available at data collection points would be sufficient.

- **Consistent Conference Call Protocols** – The individuals providing information will change throughout the New Normal period. Communications must be clear and concise and the leader of the conference calls must drive participants to stay focused on the essential elements of information; the information needed to identify issues and decide the necessary actions.
- **Communications Protocols for Field Personnel** – Develop, train, and exercise field personnel on the communications protocols they will use.
  - Prepare a specific reporting format and common protocols.
  - If needed, assign each critical data point a reporting time, so that the various parties are coordinated.
  - Prepare for an extended period of degraded communications with field personnel (i.e., posting these procedures at the stations with critical data points).
- **Protocols for Releasing Information to the Public** – Throughout the New Normal period, people will need to understand how restoration is proceeding so they can make their own decisions to care for themselves, their family, and their community. If there is limited information available from media outlets, entities could consider posting important information (e.g., rotating blackout schedules) at government offices such as police stations or post offices and at locations where people will congregate (e.g., food and water delivery points).
- **Standing Orders for Personnel** – Standing orders are a prescribed set of instructions for people to take action in the absence of communications or leadership direction. Standing orders could be developed to direct key personnel to report to designated locations following a Severe Event or direct a sub-station technician to clear each bus and open each breaker following a large scale blackout.
- **Validating Sources of Information** – The New Normal may create different operating relationships with operators communicating with and being directed by people they do not know. Consider establishing validation protocols to confirm identities. Develop "challenge and password" protocols or other information known only to certain

persons. Consider how these passwords would be developed, shared, protected, and periodically changed.

| **Key Recommendation #13 \|** Communications |
|---|
| Consider robust training, drills, and exercises to fully test critical restoration steps using alternative voice and data communications (e.g., satellite telephones). |

## 5.4 Emerging Technology Recommendations

NOTE: The following suggestions assume the Internet is available. The diverse and distributed nature of the Internet's network infrastructure makes it highly resilient. Local Internet Service Providers and the "last mile" of connectivity to the end user may be the weakest links if they are directly affected by the Severe Event.

- **Masked websites** – Entities could each develop masked (i.e., not listed under the entity's normal domain) websites to display critical readings.
  - Coordinate the development of these websites with other entities so they are designed, secured, and tested (these may require another web presence beyond your entity's currently "secure portal").
  - These websites could support data scraping so that other entities could scrape from multiple sites and upload to spreadsheets to assist in model updates or offline analysis of system conditions. To facilitate this, decide which common data format (e.g., XML, or RSS feeds) will be used. The data scraping could potentially dump the values into PSSE models or other off line studies or analysis.
- **Alternate use of security cameras** – If there is insufficient staff to read key metering points consider using security cameras be to monitor a meter (more acceptable when the threat is not a physical attack threat).
  - Consider using the physical security monitoring center to relay the meter readings to operations personnel.
  - If multiple entities require these readings consider uploading the camera feed to a webpage. This would significantly reduce the verbal reporting burden and multiple entities could access the data as their models or processes required.
- **Mobile devices** – Smart phones and tablet computers could be used as cameras, video cameras, or for conference calls.
- **Ad hoc networks** – Consider what was done during the Arab Spring uprising in Egypt to continue communications even when the Internet was significantly limited, using for example, Mobile Ad Hoc Networks (MANET).
- **Social media** – Consider using social media such as Twitter feeds for reporting. Consider developing Twitter accounts that could be used to share critical data from sub-station to control center, and control center to neighbors. This could be an extension of an entity's existing social network, but directed to system and field operations rather than consumers.

# 6.0 Short-term and Long-term System Planning

This section offers guidance for both short-term (also known as operational) and long-term system planning functions through a Severe Event. While long-term system planning functions may seem less immediately impacted by a Severe Event than other functions, both short-term and long-term system planners should be equally prepared to ensure their functional resilience.

This section considers the impact on system planners of a Severe Event that damages or degrades planning resources and capabilities.

**Experience from Hurricane Katrina**

Following Hurricane Katrina, Entergy transmission planners were unable to enter their headquarters in downtown New Orleans for several weeks. This substantially affected their ability to provide timely support, and limited confidence and speed of restoration and reconstruction efforts.

### Affected System Planners

System planners are typically divided into short-term (or operational, less than 12 months time horizon) or long-term (greater than 12 months). While there are significant differences in these functions, there is sufficient similarity in how they are affected by a Severe Event that both are considered in this section. Where appropriate, differences are noted.

### System Planning Tools and Facilities

System planning engineers typically work as integrated groups in an office environment with a central computer network, telephone network, and access to real time information from operating centers.

Information and data needed for system planning is typically in several forms: traditional paper files, drawings, and maps are located in or near the planning center, records of in-progress current project work in both paper and digital form are at the planner's desk, and shared data such as system load flow base cases are likely to be located in computer servers which may be local or remotely accessible through the IT network. Maintaining backup copies of data is typically a challenge; paper records, even if duplicated, are unlikely to be maintained in a backup location. System planners may periodically create backups of in-progress work but the copies are typically maintained locally. Only the data located on servers is likely to be adequately and securely maintained with off-site backup.

System planning tools and software are typically concentrated at one or two locations. Some software such as load flow, fault analysis, stability, relay settings, and economic analysis will be installed on individual user laptop and desktop computers and many programs require software tokens or are locked to the user's computer. More complex software and associated databases may be installed on local or networked servers. Some short-term system planning software, such as an interface to a state estimator or other real-time system information, is more likely to be installed on dedicated computers in physically and electronically secure locations.

Other system planning tools such as calculators, drafting equipment, plotters, printers, & scanners, are typically located in a central planning office for general use.

## 6.1 Consequences of a Severe Event on System Planning Functions

The consequences of a Severe Event may include the following, discussed in further detail below and elsewhere in this report.

- Temporary loss of access to system planning offices and tools
- Temporary loss of access to protected or backed up software
- Loss of communications
- Unusual demands on system planners for studies
- A need for studies of systems with multiple BPS elements out of service
- Loss of personnel, unable or unwilling to rejoin the system planning function

### Loss of Access to Facilities, Software, and Data

Loss of access to system planning offices, tools, and communications are typically addressed in business continuity plans. In the event that tools and facilities become available, but data is inaccessible, essential information will need to be developed from other sources. Operations will have backup centers where versions of system planning cases may be found. Joint and interregional studies may also be a source for replacement information.

The particular concern with loss of access is that even though it is likely that facilities and tools can often be replaced, if attention is not paid to implementing and sustaining spare equipment and data backups, a significant delay can occur before system planners are able to function again.

| **Key Recommendation #14 \|** Short-term and Long-term System Planning |
|---|
| Consider the potential loss of system planning resources (e.g., equipment, data) as well as damage to the system. Review business continuity plans to ensure that system planning resources are adequately considered. |

### Unusual Demands on System Planners for Studies

Demands on system planners will be immediate, intense, and continuous as system conditions change and configurations evolve. For example, the April 27, 2011 tornadoes affecting TVA required analysis to operate multiple unplanned islands, and study previously unconsidered configurations. Similarly, the loss of the HV transmission cables supplying the Auckland, New Zealand central business district in 2006 required planners to incorporate the temporary overhead lines.

**Experience from the 2011 Japanese Earthquake**

The 2011 Japanese earthquake and tsunami and the destruction of all transmission facilities supplying the Fukushima nuclear plant required rapid multiple expedient responses that placed extreme demands on planners.

The tasks of system planners will evolve through the mitigation, restoration, and New Normal phases of a Severe Event.

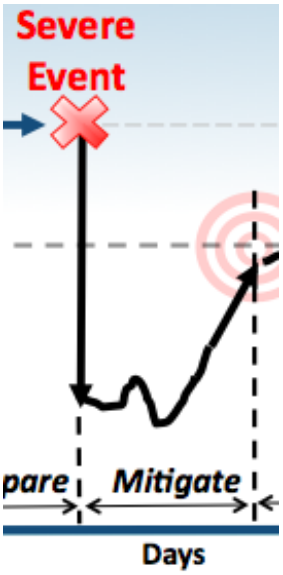
- **Mitigation Phase** – Establish and recover essential system planning facilities. Restore as much of the BPS as possible to reliable operation with a focus on supplying critical and priority loads. Perform essential studies to support BPS operation in unstudied states. Perform studies needed to support island synchronization, system reconfiguration, and potentially conflicting requirements for emergency supply to priority loads. Tasks may require only a limited number of system planners, but with specialized skills and local knowledge.
- **Restoration Phase** – Continue to recover and construct facilities adequate to support longer-term system planning. Develop the studies needed to consider options to return generation and transmission facilities to service. Begin to develop longer-term plans for new facilities. During this phase, the need for system planners may increase from a small core of specialists to a full complement of planning staff.
- **Return to Normal Phase** – Restore complete system planning capabilities. Reconcile short and long-term system planning requirements to improve BPS reliability. Resume long-term system planning functions.

| **Key Recommendation #15|** Short-term and Long-term System Planning |
|---|
| Consider the appropriate use of key system planners who may be required immediately, and for prolonged periods, to perform studies not previously considered. |

## 6.2 Planning During the Mitigation Phase

### Support Real-Time Operations

The first priority for system planners will be to establish communication with essential staff and recover essential planning facilities, information systems, and data needed to begin work. Once this is done, the immediate priority will be to support system operators in their efforts to restore the BPS and supply electricity to customers to the extent possible on a prioritized basis. The initial surviving system will likely be in an "unstudied" state. Therefore, real time assessments will need to be performed and step-by-step restoration procedures confirmed by studies before control actions are taken.




The volume of work and the need for rapid response is likely to require that some long-term system planners be re-assigned to the short-term system planning effort during the mitigation phase and perhaps even into the early portions of the restoration phase.

If there is widespread damage to the system, system planning studies may need to consider using temporary configurations such as partially restored substations. Studies may include operation with less than normal margins, contingencies that may cause loss of load, reconsideration of breaker fault ratings, and reconsideration of transformer overloads. Normal design criteria such as voltage may not apply in the early stages following the Severe Event. System planners and management should re-evaluate planning requirements considering the consequences of the Severe Event.

### Temporary Facility Ratings

System planners may need to consider temporary above-normal ratings in order to restore the BPS quickly. An ability to quickly calculate and integrate such ratings should be available.

### Replacement Equipment

While entities have the ability to withstand normal emergencies and quickly restore their systems from existing or quickly obtained spares, a Severe Event may render purchased spares unavailable for a prolonged period. In this case continuing operation with temporary design solutions using sub-optimal equipment may be required. Maintaining records and databases of equipment characteristics as reconstruction proceeds, particularly when equipment is substituted on a contingency basis, may be a challenge. While most entities have comprehensive transformer spares programs, use of spares in expedient restoration situations may result in unbalanced configurations. Studies may be required of protection and operating limits.

#### Planning Following the April 27, 2011 Tornadoes

Following the multiple tornados affecting the Tennessee Valley Authority, the Browns Ferry nuclear plant had lost all but one of its seven 500kV transmission connections. As the transmission lines were successively restored to service, multiple unstudied configurations had to be reviewed in coordination with plant restoration.

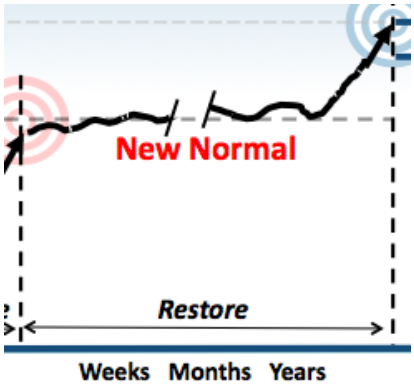
### Advance System Planning

Items of advance system planning should be considered as an aid to help speed the mitigation phase. Examples include:

- Perform system studies and maintain records of equipment interchangeability.
- Perform studies to identify the islands that would likely form during a Severe Event, and their sources of generation, including sources of generation (e.g., cogeneration at an industrial plant) not normally supplying the BPS.]

| **Key Recommendation #16|** Short-term and Long-term System Planning |
|---|
| Consider performing selected studies in advance (e.g., equipment interchangeability) that could help speed restoration. |

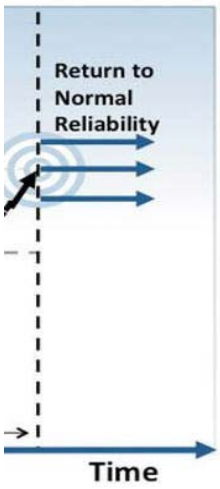
### System Planning during the Restoration Phase




As immediate real-time operating demands are met, system planning will transition from the immediate mitigation phase to longer-term restoration of the BPS. Temporary staff reassignments are likely to continue. The system planning function will grow from an initial core of specific expertise and begin to approach pre-event capabilities. In study targets, it is possible that restoration and construction will be significantly different from the original BPS configuration. Factors may include:

- Long-term loss of load, e.g., industrial or residential loads that may be lost for extended periods.
- Budget limitations as operations, maintenance and capital funds are reallocated to manage more immediate priorities. This is discussed further in the section *Emergency Financing* section of this report.

## 6.3 System Planning during the Return to Normal Phase




By this time the restoration of system planning capabilities will be complete, although it may differ from the original. System planning efforts may be required to reconcile short and longer-term plans with the requirements of the post-New Normal system and its remaining loads. System planning will likely have achieved restoration of regular planning schedules. Entities will be reflecting on their experiences and considering significant changes in long-term plans. Factors may include:

- Permanent loss of load, in particular, industrial load
- Permanent budget changes, either lower or higher, and possibly new funding and approval mechanisms
- Loss of experienced planning staff, expertise, and resources

## 6.4 Design Considerations

While system planners are typically not responsible for the physical planning and design of lines and substations, they are well positioned to offer recommendations toward improving reliability, including the following.

### Critical Spare Equipment

Emergency spares may not be identical to the equipment they replace and may result in unbalanced configurations that require protection and operating limits studies.

Entities have spare equipment criteria for critical equipment such as transformers, transmission line and substation, and generating unit components. However, a Severe Event may render purchased spares insufficient or unavailable for a prolonged period. In this case, operation with temporary designs may be required. To further enhance resilience, line and substation planning could include:

- **Increase Equipment Standardization** – To promote greater interchangeability of components, increase the standardization of component specifications such as physical size and electrical rating. For example, TVA has minimized the number of single-phase 500 kV transformer designs that it currently purchases, and has extensive studies on file of the interchangeability of differing designs. Others have established standard sizes and ratings for transformers, breakers, conductors, and other equipment.

**Standardized 500 kV Transformers used by Tennessee Valley Authority**

Following two 500 kV transformer failures in 2001, TVA developed an approach that reduced costs and procurement time, and increased interchangeability of spares by limiting transformer purchases to seven standard designs, and using external rather than internal reactors.

- **Location of Spare Equipment** – The location of spare equipment may be important. The spare equipment should be readily assessable, but a physical distance from the equipment being replaced to minimize the possibility of damage as a result of collateral or intentional actions. In higher voltage substations using banks of 3 single phase transformers, a 4th spare transformer is typical and physical separation of the spare should be part of the station design.
- **In-Situ Spares** – It is common practice to situate spares (such as high voltage transformers) adjacent to in-service equipment within same station to minimize restoration times due to equipment failure. Again, physical separation of these transformers should be maximized and otherwise protected from the potential of collateral damage caused by the destruction of the other. Other means to separate in-service spares could include using blast walls, complete redundancy in switching devices (breakers) and relay protection.
- **Use of Adjacent Substations** – Maintaining a safer distance between in-service spares could also be accomplished, depending on application and location, through storage at adjacent substations.
- **NERC Spare Equipment Database**[34] – Consider contributing spare high-voltage transformer data as part of the NERC Spare Equipment Database program being implemented in 2012.

| **Key Recommendation #17|** Short-term and Long-term System Planning |
|---|
| Consider the spare equipment critical to BPS restoration and ways to improve availability of these spares. |

### Use of Rights-of-Way

Utilities that operate in areas prone to tornados recognize the possibility of simultaneous loss of all transmission lines on a single right-of-way. Other Severe Events such as earthquakes,

[34] Ref. NERC Spare Equipment Database Task Force report http://www.nerc.com/filez/sedtf.html

unusually extreme ice storms, and physical or cyber attacks may also threaten multiple facilities using a common right-of-way.

- While it is common practice to concentrate multiple circuits onto a single right-of-way, consider minimizing the impact of a single mode failure on the facilities. For example, single circuit towers may be less vulnerable to disruption and facilitate energization when crews are working on adjacent structures.
- Some circuits could be built underground to reduce the vulnerability of all circuits along the right-of-way.

### Station Design

The implementation of the NERC Critical Infrastructure Protection (CIP) standards[35] have helped enhance physical and cybersecurity at substations. However, many substations are often not staffed and monitoring is limited to visual security cameras and alarms and control devices used for electrical operation. Suggestions to improve resilience include:

- Install electronic surveillance to facilitate remote visual inspection and assist in setting priorities for operation, repair, and identifying alternatives for restoration.
- Harden structures and control houses to minimize damage and improve restoration efforts.
- To reduce exposure to explosions, use physical separation or blast containment techniques.
- Standardize the use of protection and control devices and schemes to ease repair or replacement. Consider using alternate technologies for backup systems that are simple yet effective.

**Use of Modular Control Houses by American Electric Power**

AEP is working with suppliers to develop modular control houses with Faraday cage shielding of devices and protection cables that would harden critical cyber assets serving large metropolitan areas.

[35] NERC CIP-002 – CIP-009: http://www.nerc.com/page.php?cid=2|20

# 7.0 Protection and Control

This section identifies challenges associated with protection and control systems used to support the reliable operation of the BPS following a Severe Event and a prolonged period of New Normal operation. It is important to understand the differences between a power system protection engineer's two competing objectives.

| Dependability and Security | | |
|---|---|---|
| **Power system protection engineers must optimize the balance between the two conflicting goals of dependability and security. In general, enhancing dependability implies an intrinsic loss of security and vice versa.** | | |
| **Dependability** is "the degree of certainty that a relay or relay system will operate correctly"[36]. |  | **Security** is "the degree of certainty that a relay or relay system will not operate incorrectly"[37]. |

Protection and control plays a major role in BPS reliability. An analysis of historical NERC outage reports indicates that hidden failures[38] are involved in over 70% of cascading outages. The probability of a hidden failure occurring is likely greater under the stressed system conditions following a Severe Event. Therefore, the severity of the event and the prolonged duration of the New Normal justify a thorough assessment of protection and control systems to help ensure reliable operation.

Protection schemes depend entirely on the local configuration of the BPS and vary significantly from utility-to-utility and region-to-region. While this section does not provide step-by-step

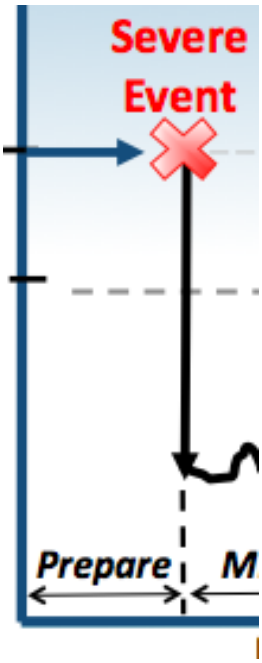
[36] Ref. IEEE Standard for Relays and Relay Systems Associated With Electric Power Apparatus," *IEEE Std C37.90-2005 (Revision of IEEE Std C37.90-1989),* pp. 0_1-19, 2006. [1]
[37] Ibid.
[38] A hidden failure is defined as a permanent defect on a relay system that will cause the incorrect removal of a circuit element as a direct consequence of another event [2] Tamroglak, "Analysis of Power System Disturbances due to Relay Hidden Failures," ECE, Virginia Tech, Blacksburg, VA, 1994. As conveyed by the definition, hidden failures remain dormant until a particular event causes its manifestation and associated relay miss-operation.

instructions or guidance on specific protection schemes, it does emphasize key considerations and potential mitigation actions to enhance reliable protection and control systems.

## 7.1 Preparation Phase

The NERC cybersecurity standards[39] require that critical cyber assets such as certain protection and control devices and systems be protected. The following offers industry practices best employed prior to a Severe Event.

### Physical and Cybersecurity




- Instead of using manufacturer default passwords, consider using strong[40] passwords, change them periodically, and use different passwords for each control house and/or each protection relay.
- Consider performing periodic comparisons between "as-left" relay setting files in the field with setting files at the main office.
- Consider monitoring access into substation, control house, and protection relays.
- Consider enhancing physical security of equipment in the switchyard.
- Emphasize "need-to-know" and restrict access to critical assets and information.
- Consider encrypting communications of all critical data.
- Consider having redundant secure communication paths to critical assets to decrease the impact of denial of service attacks and to provide an alternative path for alarm and mitigation action.
- Consider developing procedures to disable bi-directional data flow in substations to prevent network access to protection relays. The intent is to prevent intruders from being able to remotely log into relays and alter relay settings, yet still allow the relays to perform their normal protective function. The procedure should not compromise SCADA data; disable communications from the communication processor to relays, and therefore only allow uni-directional data flow from the relays to the communications processor.

### Power Supply to Protection and Auxiliary Systems

- Determine battery backup power requirements for substation loads such as the control house and station service under a Severe Event scenario.
- Consider installing permanent or portable backup generation to charge batteries at critical substations.

[39] NERC Cybersecurity standards CIP-002 – CIP-009 http://www.nerc.com/page.php?cid=2|20
[40] US-CERT Cyber Security Tip ST04-002 http://www.us-cert.gov/cas/tips/ST04-002.html

- Understand the interdependencies between stored energy in circuit breakers and substation off-site power. For example, spring-spring circuit breakers have stored energy for an open-close-open (O-C-O) operation. The motor to charge the spring mechanism may be AC or DC driven, or both. If the motor is AC driven and the station service transformer is out of service, then only an O-C-O operation is allowed.

### Communications Infrastructure

- It may not be possible to operate equipment remotely. Consider the logistics required to dispatch staff to multiple critical substations to monitor and manually operate equipment.
- Understand the interdependencies between protection systems and the communication infrastructure. As an example, consider a Direction Comparison Blocking (DCB) scheme. If the communication between substations is compromised, the scheme will lack security (i.e., the relay may misoperate for a fault outside the protected zone). However, the dependability of the scheme will not be affected.

### Control House

- Consider a mobile control house for rapid restoration of critical substations [3]. The design of a mobile control house should address transportation, flexibility to adapt to multiple protection schemes, battery and generator backup power, test and control switches, communication equipment, etc.

### Organizational Resilience:

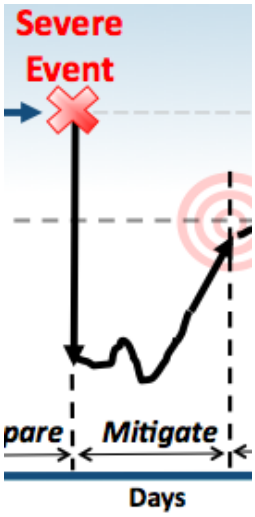
- Consider developing contacts and communication protocols to request the assistance of relay technicians and engineers from neighboring utilities that may not be as affected.
- Consider developing procedures to designate responsibilities to optimize protection and control under the New Normal. Consider tasks such as:
  - Creating a new system model for protection studies
  - Identifying personnel to assess the adequacy of protection settings considering local circumstances under the New Normal
  - Identifying personnel to update relay settings
  - Developing a priority list for protection relays
- Ensure that appropriate communication channels exist between protection systems engineers and power system operators.

### Particular Considerations

- Assess the potential impact of a geomagnetic disturbance[41] on protection schemes. Harmonic distortion[42] may cause misoperations [4]. For example, certain shunt capacitor unbalance protection schemes may misoperate as a result of system harmonics. A potential mitigation is to use a voltage differential scheme to protect shunt capacitor banks. Consider the impact on the security-dependability balance on schemes that use harmonic restraint (e.g., transformer differential). Consider the potential impact of harmonic distortion on power system equipment such as harmonic filters, capacitor banks, SVC, communication equipment, generators.
- Assess the potential impact of a coordinated cyber attack on protection systems. A potential mitigation is to isolate systems, including any remote access to these systems, during periods of heightened concern.
- Assess the vulnerability of communications infrastructure to ensure data availability, integrity, and confidentiality: point-to-point fiber, power line carrier, synchronous optical networking (SONET) ring, third party provider network, etc.

## 7.2 Mitigation Phase

Immediately following the Severe Event, protection systems will respond according to predefined settings; adjusting protection relay settings as the event is evolving is not feasible. Response may be limited to confirming the status of protection systems.



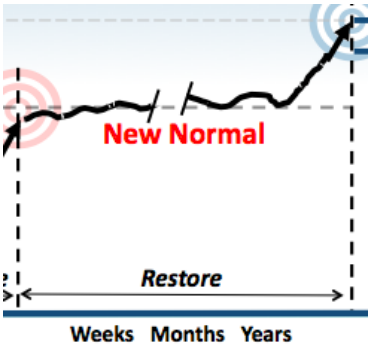

- If a cyber attack is suspected, compare "as-left" setting files in the field with setting files at the main office.
- Taking into consideration potential new islanded configurations, prioritize assessments at critical substations and generation facilities (ref. *Operations, Island Stability* section).

[41] Ref. *Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System* http://www.nerc.com/files/2012GMD.pdf. This report concluded that the loss of reactive power is the most likely outcome from a severe solar storm centered over North America.

[42] Consider the operating quantity measured by protection relays: fundamental component (digital vs. analog filter), RMS values, etc.

## 7.3 Restoration Phase

A highly stressed system should be expected during the New Normal period, characterized by islanded operation, rotating blackouts, lower system inertia and higher network impedance (i.e., reduced synchronizing torque), different short circuit currents and critical clearing times, and reduced stability margins. Through the New Normal, protection relay settings may not be optimal and unwanted operations may occur.




### System Restoration and Control

- Consider station service at substations along restoration paths to be critical loads.
- Assess physical damage on protection and control communication channels: wave traps, fiber channels, microwave, etc. Non-pilot distance protection of transmission lines may become primary protection until infrastructure for pilot schemes (that require a communications channel) is provided.
- Remote power system control may be compromised. Dispatch personnel to critical substations for manual operation of equipment.
- Assess physical damage to substation control houses. Ensure adequate protection relay equipment is readily available.
- No damage to protection relay devices is expected after a GMD event. Current transformers may have remanence flux, which can shorten the time-to-saturation; this should not be a problem for high speed protection [4].
- If traditional telemetry or access to SCADA/EMS is compromised, consider using monitoring and control capabilities embedded in microprocessor-based protection relays.

### Reliability of Protection Schemes

- Consider revisiting protection settings to enhance the security-dependability performance of the protective equipment. Protection relay settings are developed based on an assumed system state. Such settings may become unreliable under the New Normal; critical clearing times may be reduced, short circuit currents may change, and stability margins may be reduced. It may be possible to optimize the reach of protective zones.
- Consider a reliability bias towards security [7]. Traditionally, protection systems have been biased towards dependability. Under normal conditions, system topology and good stability margins justify such a design. For example, multiple transmission lines provide a number of alternate paths for power to flow and the BPS can withstand losing a single line as a result of conservative protection security provided the remaining transmission lines have sufficient loading margins. Under such conditions, not clearing a fault with primary protection has a greater impact on the system than a relay mis-operation due to lack of security. However, under New Normal conditions, the power system may be in a highly "stressed" state. Unnecessary line trips may further

exacerbate system conditions, contribute to the geographical propagation of the disturbance, and may even lead to cascading events and subsequent blackout.

- Consider studying cascading outages. The BPS may not be secure enough to withstand the next contingency (N-1); consider reviewing existing and developing new SPS and RAS schemes.
- If rotating blackouts are implemented, consider studying the impact of cold load pick-up on distribution protection with Distribution Service Providers.
- Assess source strength for distribution circuits. If short circuit currents do not allow protection coordination, consider implementing voltage supervision.
- With stability margins significantly reduced, under frequency load shedding (UFLS), under voltage load shedding (UVLS), and special protection schemes (SPS) may be essential to ensure a reliable operation of the power system. Review and ensure the appropriateness of existing UFLS, UVLS, and SPS schemes [8-14]. Consider deploying additional schemes to better suit the prevailing system state. The main three parameters involved in designing UFLS and UVLS schemes are:
  - When to shed load (threshold setting)
  - How much load to shed
  - Where to shed load

**Importance of Relay Setting Parameters**

All three parameters are important. During the July 1996 WSCC blackout, [12] load was shed at the power sending side which caused several tie-lines to become overloaded which in turn led to a loss of synchronism. In the 1977 New York blackout [15] generator excitation protection tripped several machines after a voltage rise caused by load shedding.

| **Key Recommendation #18 \|** Protection and Control |
|---|
| Consider ways to implement large-scale changes in system protection schemes to support islanded operation and changing BPS configurations, and what decision points would be needed. |

| **Key Recommendation #19 \|** Protection and Control |
|---|
| Consider ways to quickly reconfigure relay settings in the event large-scale changes are needed. |

## Distribution System Impacts and Mitigations

Large magnitude geomagnetically induced currents are not expected to flow in the distribution system. However, the impact of harmonic distortion on any distribution-level protection systems should be considered.

## 7.4 Training

Due to the challenges posed by operating the power system under the New Normal, personnel training is a critical factor to ensure a resilience power system. Training opportunities may include:

- Consider cross training between distribution and transmission relay technicians and engineers to allow flexible reallocation of personnel.
- Consider developing an instruction manual describing the system protection philosophy. The intent is to facilitate the learning process in case system protection personnel are shared among utilities. The manual should address protection scheme designs, protection relays used, communication equipment needed, etc.
- Before attempting to synchronize islands, ensure that mechanisms are in place to identify and coordinate any changes to protection systems (i.e., SPS, UFLS, UVLS schemes) that could affect neighboring entities.

### References

[1] "IEEE Standard for Relays and Relay Systems Associated With Electric Power Apparatus," *IEEE Std C37.90-2005 (Revision of IEEE Std C37.90-1989),* pp. 0_1-19, 2006.

[2] Tamroglak, "Analysis of Power System Disturbances due to Relay Hidden Failures," ECE, Virginia Tech, Blacksburg, VA, 1994.

[3] R. Mazzatto, M. Leschuk, R. Glass, R. Brown, and D. Schmidt, "Case Study: Mobile Protection Unit for Rapid Power Restoration," *65th Annual Georgia Tech Protective Relaying Conference,* May 2011.

[4] "Geomagnetic disturbance effects on power systems," *Power Delivery, IEEE Transactions on,* vol. 8, pp. 1206-1216, 1993.

[5] UCTE, "Final Report of the Investigation Committee on the 28 September 2003 Blackout in Italy," ed, 2004.

[6] NERC, "Final Report on the August 14, 2003 Blackout in the United States and Canada," ed, 2004.

[7] E. Bernabeu, "Methodology for a Security-Dependability Adaptive Protection Scheme based on Data Mining," Ph.D., ECE, Virginia Tech, Blacksburg, VA, 2009.

[8] NERC, "Assessment of the Design and Effectiveness of UVLS Program," 2005.

[9] NERC, "UVLS System Maintenance and Testing," 2005.

[10] NERC, "Assuring Consistency with Regional UFLS Program Requirements," 2005.

[11] NERC, "Underfrequency Load Shedding Equipment Maintenance Programs," 2005.

[12] NERC, "Review of Selected 1996 Electric System Disturbances in North America," 2006.

[13] NERC, "Under-Voltage Load Shedding Program Data," 2006.

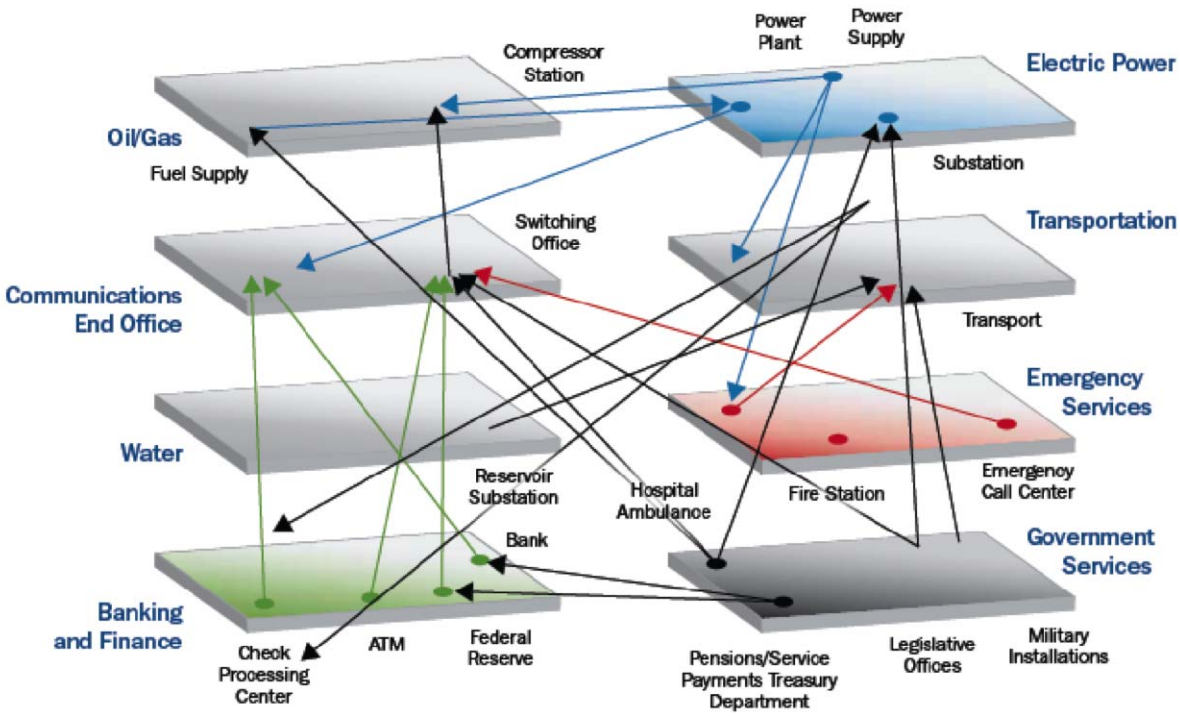
[14] NERC, "Under-Voltage Load Shedding Program Performance," 2006.

[15] FERC, "The Con Edison power failure of July 13 and 14, 1977: final staff report," ed. Washington, 1978.

# 8.0 Interdependencies with Other Critical Infrastructures

A Severe Event that broadly affects the BPS will in all likelihood have a significant impact on other critical infrastructures that depend on the reliable and continuous supply of electricity. Similarly, the BPS relies on other critical infrastructures that are necessary to support BPS restoration and operation. This section considers both aspects of these interdependencies.

**Figure 6: Critical Infrastructure Interdependencies**[43]




The U.S. and Canadian governments have programs in place to encourage greater protection and resilience of our nations' critical infrastructures. In Canada, "The *National Strategy and Action Plan for Critical Infrastructure*[44] establishes a risk-based approach for strengthening the resiliency of Canada's vital assets and systems such as our food supply, electricity grids, transportation, communications and public safety systems." Similarly, in the United States, the *National Infrastructure Protection Plan*[45] prepared by the U.S. Department of Homeland Security identifies 18 critical infrastructures.

[43] Source: Department of Energy, Energy Sector Specific Plan http://www.dhs.gov/xlibrary/assets/nipp-ssp-energy-2010.pdf
[44] Public Safety Canada: http://www.publicsafety.gc.ca/prg/ns/ci/index-eng.aspx
[45] DHS Critical Infrastructure: http://www.dhs.gov/files/programs/gc_1189168948944.shtm

The table below illustrates the extent to which electricity is interdependent with many other infrastructures. These are discussed more fully in later sections.

**Table 5: Key BPS Interdependencies**

| Critical Infrastructure | BPS Depends on Infrastructure for: | Infrastructure Depends on Electricity for: |
|---|---|---|
| Banking and Finance | Funds transfer | Funds transfer, cash distribution, functioning of the economy |
| Communications | Voice and data services | Voice/data centers and networks, internet providers |
| Dams (hydroelectric) | Energy source | Station service |
| Defense Industrial Base | - | Military bases and defense production facilities |
| Energy – Coal, Oil & Natural Gas | Electricity generation fuel source<br>Backup generators, service vehicle fuel | Fuel production and transportation (pumping) |
| Energy – Electricity | Station service | Station service |
| Food and Agriculture | Food production (staff well-being) | Irrigation and food production |
| Government Facilities | - | Facility service |
| Healthcare | Staff well-being | Facility service |
| Information Technology | Automated tools | Facility service |
| Nuclear | Electricity generation fuel source | Station service, including safety systems |
| Transportation | Staff and equipment transportation | Communications and control systems operation |
| Water | Electricity generation cooling<br>Staff well-being | Pumping and processing |

The following describes some of the significant dependencies of the BPS on other critical infrastructures needed to support mitigation and restoration through a Severe Event.

## 8.1 Communications Sector

In addition to affecting the BPS, a Severe Event may also degrade the communications infrastructure. System operators may not be able to rely on telephone, cellular, email or dedicated broadband networks to communicate with entity staff, other entities, and key stakeholders. Alternative communications facilities need to be in-place and tested in advance of a Severe Event.

Effective BPS restoration and continued operation is highly dependent upon the ability to communicate, both voice and data, at all times. The highly interdependent aspect of BPS recovery and the communications infrastructure cannot be over-emphasized. Communications infrastructure and protocols are discussed in further detail in the Communications section.

**Recommendations:**

Entities should work closely with their communications service-providers to better understand mutual dependencies, identify priorities, and seek ways of mitigating the impact of severe disruptions.

- Identify specific interdependencies between telecommunication infrastructure and BPS infrastructure, such as voice and protection circuits, SCADA, remote terminal units and smart grid devices, necessary for BPS operations (e.g., key telecommunications facilities and their power system restoration paths and priorities).
- Ensure that critical telecommunications users are registered for priority wireless and land-line services such as:
  - U.S. Government Emergency Telecommunications Service[46] (GETS)
  - U.S. Government Wireless Priority Service (WPS)[47]
  - Industry Canada's Wireless Priority Service[48] (WPS).
- Identify risks and hazards such as failures, attacks, High Impact Low Frequency Events and/or congestion etc., that could impair the quality of service continuity, readiness, performance and time response of telecommunications.
- Explore opportunities and needs associated with emerging technologies (e.g., future 700 MHz, 1.8 GHz bandwidth frequencies, WIMAX, wireless priority services).
- Take mitigation measures (e.g., operational procedure changes, changes to priorities and procedures in restoration plans, design considerations, inter-entity information exchange).

[46] U.S. GETS http://gets.ncs.gov/
[47] U.S. WPS http://wps.ncs.gov/use.html
[48] Canadian WPS http://www.ic.gc.ca/eic/site/et-tdu.nsf/eng/h_wj00016.html

| **Key Recommendation #20 \|** Interdependencies with other Critical Infrastructures |
|---|
| Consider working with communications service providers to identify which of their facilities are critical to BPS operations. Determine which BPS and distribution facilities supply them and what backup power capacity is in-place (e.g., batteries, standby generators). |

## 8.2 Dams (hydroelectric) Sector

Hydroelectric dams provide substantial generation in many regions of North America, and often provide critical blackstart services, as well as control water flows for irrigation, navigation, and elevation. Failure of key dams could have a significant effect on BPS operations.

### Recommendations:

- Operators should develop a comprehensive understanding of the location and characteristics of hydroelectric facilities in their area and consider their ability to restart these facilities following a blackout.
- Some dams may be of more critical importance in their role of navigation, such as enabling coal supply via barge to key generating stations. Operational plans should identify the generators dependent upon navigable inland waterway supply for fuel transport or cooling water.

## 8.3 Energy Sector

The energy sector, in addition to electricity, includes natural gas, petroleum, and coal. Disruption to any of these fuel infrastructures could seriously impede BPS restoration.

### Recommendations – Coal

- According to the U.S. Energy Information Administration, coal currently accounts for almost half of U.S. electricity generation[49]. Coal-fired generators are dependent upon frequent, in some cases daily, supply of coal from mine to power plant.
- Operators should ascertain and maintain cognizance of on-hand fuel supplies and storage capacity at coal fired generators.
- Operators should understand the coal transport routes in their area, consider possible supply disruption points, and explore alternate routes or transport modes.
- Operators should develop contingency plans around “out of fuel” scenarios in the coal fleet. What would New Normal operation look like in a short coal supply scenario?

### Recommendations – Natural Gas

- Entities should understand[50] the gas pipeline networks and arrangements in place to supply gas-fired generators in their footprint (e.g., gas-fired generators and pipelines

[49] http://www.eia.gov/energyexplained
[50] Ref. NERC Natural Gas and Electric Power Interdependency report http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf

that supply them, operator communications protocols during normal operations and emergencies).

- System operators should know which pipeline compressor facilities are gas versus electric powered and what gas pressure drops might be in the event of a sustained BPS outage. System operators will need to work with gas counterparts to understand power outage impacts on gas supply, and vice versa, and identify which are priority loads.
- In the event of a physical or cyber attack on gas infrastructure (including gas SCADA systems), system operators should consider the impact on gas-fired generation, and encourage their gas counterparts to share their plans to respond and restore operation.
- System operators should coordinate with gas operations personnel concerning their load shedding priorities.

### Recommendations – Oil

- Oil is a relatively minor fuel source for the BPS, however system operators should assume these units will be unavailable due to unprecedented demand for diesel and gasoline fuel for standby and backup generators.
- Diesel fuel is needed for emergency standby generators at all critical BPS facilities that are without a reliable supply of power from the BPS during restoration. Entities should review contractual arrangements and establish priorities with fuel suppliers.
- Diesel and gasoline fuel is needed for transportation purposes. Regional Entities may wish to consider establishing regional fuel reserves for use in severe emergencies when normal fuel delivery channels may not be available for extended periods or when competing fuel demands (e.g., National Defense) take precedence for available supplies.

| **Key Recommendation # 21 \|** Interdependencies with Other Critical Infrastructures |
|---|
| Consider alternate suppliers, transportation paths, and agreements to support generating station fuel supply chains (e.g., coal, natural gas). |

## 8.4 Information Technology Sector

Reliable operation of the BPS is highly dependent on the IT sector. IT is in turn heavily dependent upon electricity. Over the past decade, many entities have chosen to purchase or lease commercially available IT[51] systems and networks rather than build and support their own. Cyber attacks continue to increase in frequency and sophistication. System operators should be aware of the extent to which they rely on IT infrastructure, and should develop plans and procedures to enable recovery and New Normal operations in the event of significant disruption to the IT infrastructure.

### Recommendations:

- Operations staff should work with entity IT staff to develop a comprehensive understanding of the IT infrastructure on which BPS operations are dependent. Consider elements of the infrastructure outside entity direct control, network interfaces

[51] In the context of this section, IT refers to entity business systems, rather than operational EMS or SCADA systems.

(if any) with operational systems such as EMS and SCADA, redundant systems and backup plans.

- Consider developing detailed operational plans in the event of major disruption to the internal or external IT infrastructure and Internet.
- Develop backup plans for telemetry that is critical to BPS operations in the event of a major IT infrastructure disruption.

| **Key Recommendation #22 \|** Interdependencies with Other Critical Infrastructures |
|---|
| Consider working with information technology service providers that are critical to BPS operations and consider augmenting the subject matter expertise of staff and suppliers to support these systems. |

## 8.5 Nuclear Sector

Nuclear power plants are a key part of the generation infrastructure, providing 20% of electricity in the U.S. and about 15% in Canada. This segment of the power sector has long been heavily regulated from a safety and security perspective. Because of its unique nature and national security importance in the U.S., the nuclear sector was designated as its own critical infrastructure by the U.S. Department of Homeland Security, and has its own Sector Specific Plan under the National Infrastructure Protection Plan (NIPP). System operators are well versed in handling nuclear plant outages, and in the dependence of nuclear plants on BPS-supplied electricity. However, recent incidents, such as Fukushima, have focused renewed attention on the interdependencies of nuclear plants, the grid, backup fuel supply for cooling, and the transportation infrastructure to move that fuel. BPS restoration and New Normal operation should take into account the disruption of and potential long-term unavailablility of key nuclear power plants.

### Recommendations:

- The industry is extensively studying the lessons learned from Fukushima. These lessons should be incorporated into BPS restoration and recovery plans.
- Nuclear plant operators and system operators should carefully calibrate plans and procedures[52] in the event of major disruption to either infrastructure.
- As has been learned from the Fukushima event, emergency cooling for nuclear plants highlights several key interdependencies: water, fuel, and transportation. Recovery plans and procedures should take account of these infrastructure interdependencies.
- Once off-line, nuclear plants can be out-of-service for extended periods. Recovery and New Normal operational plans should consider these implications carefully, particularly if nuclear generation provides a substantial source of energy to the area.

[52] NERC standard NUC-001 Nuclear Plant Interface Coordination http://www.nerc.com/page.php?cid=2|20

| **Key Recommendation #23 \|** Interdependencies with Other Critical Infrastructures |
|---|
| Consider alternate means to supply BPS power to nuclear plants and confirm these loads as critical to restoration and public safety. |

## 8.6 Transportation Sector

The transportation infrastructure is highly complex. It includes rail, waterborne transport, surface transport, and aviation as well as pipelines that transport natural gas, crude oil, petroleum products, and water. All of these infrastructures are critically important to BPS operations. Almost half of generation is dependent upon coal that is transported via rail and barge. (Barge transport can be very dependent upon river/navigation conditions, including flooding, low water, and accidents.) Pipelines move the natural gas that fuels a quarter of the generation fleet, and is forecast to increase over time. Surface transport moves fuel for backup generation and mobility. In the future, electric vehicles will introduce new interdependencies as they consume electricity and may provide new demand response opportunities. Disruptions to any of these infrastructures can heavily impact BPS restoration and New Normal operations.

### Recommendations:

- Emergency plans should be developed that "work backward" to inventory the transport dependencies affecting BPS operations, including basic requirements such as transporting workers to and from work locations.
- Emergency plans should identify suppliers of diesel fuel and gasoline for service vehicles and emergency backup generation and review how these supplies will be prioritized through a Severe Event.
- Backup and re-routing plans should be developed in the event of major disruption to primary transport networks. This could include secondary and tertiary routing plans to move coal, gas, and petroleum products. Disablement of a key river lock or railroad bridge, or key pipeline, could seriously affect BPS restoration. Alternative routing/sourcing should be planned for in advance.
  - In addition to evaluating existing stockpiles at generating stations, Operators should consider re-establishing coal inventory needs if operating in an islanded configuration for a considerable period of time, and consider if coal can be re-dispatched to more critical generators.
  - Operators should work with rail service providers and government to consider how to prioritize the shipment of coal or other fuels to priority generators.
- Operators should consider consulting with government to consider establishing strategic reserves of key fuels to be used in the event of significant supply disruption. This could be a shared regional system, modeled on the U.S. Strategic Petroleum Reserve.
- Transportation dependencies go beyond fuels. The transportation of key pieces of equipment, such as transformers[53], and other spare parts essential to BPS restoration. The same planning should be considered for these other items, to include alternative sourcing and transport mechanisms.

[53] Ref. NERC's Spare Equipment Database program http://www.nerc.com/filez/sedtf.html

## 8.7 Critical Infrastructure Sectors that Depend on Electricity

All critical infrastructures depend on electricity to varying degrees. System operators, working in consultation with other critical infrastructures and possibly local, state/provincial, or federal government authorities will need to prioritize loads and understand the extent to which they will be supplied through the mitigation and restoration phases following a Severe Event. Some of these infrastructure sectors and their importance in a Severe Event are briefly described below.

- **Government and Emergency Services:** In a Severe Event affecting the BPS, priority loads may include certain government loads, particularly those with no backup emergency power source. This may include police/fire, emergency services, command centers, and key military facilities. This will be critical to ensuring law and order and effective governance.
- **Defense Industrial Base:** Should a Severe Event be associated with an act of war, or a substantial threat to the National Security, supplying key elements of the defense community and its industrial base would become a priority load.
- **Water:** Water is essential for life. Failure to treat wastewater could result in widespread disease. Hence, supplying electricity for water and wastewater treatment plants and pumping stations will likely be a high priority load for restoration.
- **Healthcare:** Hospitals and healthcare facilities are always a high priority in an outage situation, and will be in any Severe Event to handle injuries or disease.
- **Agriculture and Food:** Food supply will be an important priority in a Severe Event. Electricity for irrigation pumping, food processing, and related purposes will be essential.
- **Banking and Finance:** An important priority will be to restore and maintain commerce. Thus the banking sector will be a priority load.

System operators should work with government authorities and other stakeholders to develop a plan for addressing these critical infrastructure sectors in the event of a severe BPS disruption. Most operators know their critical and priority loads under normal recovery operations, such as hurricanes and ice storms. However, new protocols may need to be developed to address these loads in the context of BPS restoration and New Normal operation after a Severe Event.

### Training and Exercises

Training will be an absolutely critical element for personnel at all levels in order to gain an understanding of what types of conditions may be encountered in all phases of an emergency, and what the key interdependencies could look like. System Operators, field, and support staff will need this training as will senior management and other key stakeholders, including Government officials, law enforcement, defense, etc. Representatives of interconnected infrastructures should also be included so that information can be shared on key interdependencies and likely response patterns (this can avoid recovery procedures working against each other). The concept of a multi-sector New Normal should be a main theme of this training.

The training cannot envision every possibility. A major part of the training (like survival training) is to engender resourcefulness and flexibility in operational personnel. They understand the outlines of the problem and can then react to the situations at hand.

Realistic exercises should be a key part of the program. Exercises should include BPS personnel at all levels, plus key government representatives, and subject matter experts from other critical infrastructures. The exercises should be carefully documented and thorough after action reports prepared so that learning can be factored into planning and continuous improvement.

These activities should also be coordinated with the National Infrastructure Protection Plan, the National Response Plan and similar coordination elements of the federal and state/provincial governments of both countries.

# 9.0 Coordination with Government

Local, state/provincial and federal governments (government authorities) are key stakeholders in the electricity industry's response to a Severe Event. These government authorities are responsible for emergency planning and response, developing energy security and reliability policies. In the event of a Severe Event that spans a broad geographic area, government authorities – and perhaps the military – will have a large role to play. Just as the response by electricity entities to any Severe Event will be driven through local and regional entities first and foremost, the response from government will also likely be foremost a local and state/provincial response. As such it is important to be prepared to work with government authorities at all levels:

- Plan for a Severe Event, share your plan with government authorities, and know their plans.
- Understand local and state/provincial government concerns and provide them with information that will help address these concerns.
- Understand in advance how government may be able to assist during a Severe Event. Government authorities may be able to assist by providing resources or information.

This section provides a number of recommendations to enhance communication and coordination on the following topics:

- Overview of government authorities
- Coordination and communications prior to a Severe Event: planning, exercising, and training
- Initial communication and coordination
- Coordination and communication during restoration

## 9.1 Overview of Government Authorities

In order for entities to determine the government agencies they will need to coordinate with, entities need to understand the roles that government and first responders play, as well as their authorities and legal responsibilities. This will avoid potential conflicts, enhance coordination, and help each other understand respective needs. Entities charged with directing response and restoration should be familiar with government procedures for declaring emergencies at the local, state/provincial and federal levels. The laws, regulations, and plans for declaring emergencies and invoking emergency authorities are readily available on government websites. Entities should review the relevant emergency-related legislation and plans, understand the roles and responsibilities, and determine in advance of a Severe Event their points of contact with the appropriate government authorities. Involving these points of contact in entity emergency exercises will enhance entity understanding of the role of government authorities and help build positive relationships.

Some examples of government authorities involved in managing emergencies include:

- **Local and state/provincial emergency management** agencies and first responders, who prepare for and respond to all emergencies, especially those with responsibilities for the

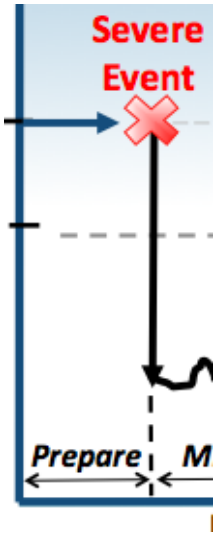
energy sector. These organizations are on the front line of emergency response at the local and state/provincial levels.

- **The lead authority for emergencies (usually activated at the Emergency Operations Center)**. State/provincial governments have a designated primary contact for managing emergencies.
- **State Governors** and provincial Premiers possess emergency authorities that they can exercise to mitigate the impacts of emergencies. Increasingly, state/provincial authorities (e.g., **State Homeland Security Directors)** have protection and vulnerability assessment programs in place involving the critical infrastructure sectors.
- **State/Provincial regulators, such as public utility commissions**, who oversee and regulate multiple sectors and systems, such as natural gas, telecommunications, and water systems, as well as important elements of the transportation infrastructure. This provides them with the capability to connect information between interdependent systems, and may also provide a nexus of infrastructure information that crosses a number of sectors at once. **State/provincial energy offices** typically serve many energy-related functions at the state/provincial level, including coordinating responses to energy emergencies, developing state energy emergency plans, and developing practices to improve energy security and reliability at the state-level.

| **Key Recommendation #24 \|** Coordination with Government |
|---|
| Confirm the roles, authorities, and points of contact between BPS entities and as appropriate, local, state/provincial, and federal governments. |

## 9.2 Coordination and communications prior to an event: planning, exercising, and training

**Critical and priority loads**: Entities should work with government at all levels to inform them of the power system loads considered critical to power system restoration. Entities should also consult with government to identify priority loads that are essential to public health and safety. Establishing a common understanding of these loads prior to a Severe Event will help provide a basis to confirm or adjust these priorities, depending on the specific circumstances following a Severe Event.




| **Key Recommendation #25 \|** Coordination with Government |
|---|
| Coordinate with local and state/provincial government authorities and consumer stakeholders to identify priority loads to mitigate the impact on public health and safety. |

**Requesting regulatory exemptions and waivers**: Entities understand that its operations need to comply with all applicable international, federal, state/provincial, local laws, standards (e.g., NERC Reliability Standards, OSHA, and Department of Transportation), codes, executive orders

and regulations. However, during a Severe Event, entities should consider seeking exemptions from certain regulations if this helps improve overall public safety.

Entities should identify waivers they may request from state/provincial and federal agencies to continue operations under stressed conditions (e.g., environmental emissions, truck driver hours). Identify entity and agency emergency contact information and know each waiver's limitations (i.e., expiration and renewal terms). Work with government authorities to confirm detailed procedures. Keep any required forms available and completed in advance to the extent possible, and review them annually.

| **Key Recommendation #26 \|** Coordination with Government |
|---|
| Consider developing a list of regulatory exemptions or waivers that will materially improve restoration and operation (e.g., plant emissions, truck driver hours) and consult with state/provincial and federal agencies. |

**Credentialing**: Government first responders (e.g., police, fire, ambulance) have become more aware in recent years of the need to provide access to critical infrastructure work crews. Access to the affected area will be important as soon as it can be provided safely. If possible, access policies should be established with government authorities prior to a Severe Event. Areas with a history of reliance on mutual assistance for recurring disasters (such as for hurricane response) may have protocols in place; in the event of a Severe Event some protocols (depending on communications systems that may not be operational) may need to be available for use without transmittal, or a working access and credentialing protocol may be needed.

### Recommendations:

- Consider consulting with government authorities to understand what access policies may be in place during a Severe Event.
- Consider having entity staff meet with local law enforcement personnel to discuss access requirements and build a cooperative relationships.

### Considerations:

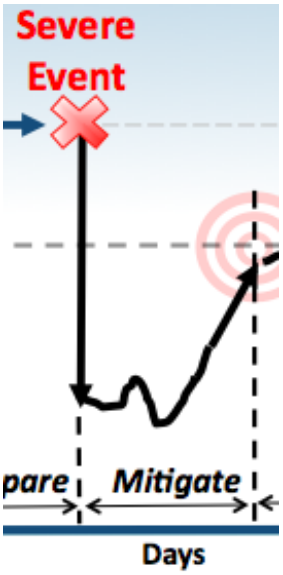
- Do you know what kind of documentation would be needed to reenter affected areas?
- Is there a plan in place to procure and disseminate the necessary documents if communications systems are down?
- Have you discussed an access plan with government authorities that cover you, your mutual aid, and contractors? Consider alternatives in case information technology is compromised.

**Building Trust with Decision Makers**: Realistic exercises that involve entity personnel at all levels, key government staff, and other critical infrastructures are essential to preparedness. Following exercises, participants should identify action items and next steps for future planning and continuous improvement.

**Budgets**: Governments have the means to declare a state of emergency and invoke the authorities needed to respond to the situation. Entity emergency management plans should recognize government roles and responsibilities when they exercise that authority, and how they will become aware of changes that may impact entity operations. Entities should engage with government to help ensure a common understanding of mutual needs.

## 9.3 Initial Communication And Coordination

It will be very important that entities begin communicating with the appropriate government authorities at a very early stage of a Severe Event to provide updates both on a scheduled basis, and as urgent developments occur. This will help ensure that decisions are made using the best available information.

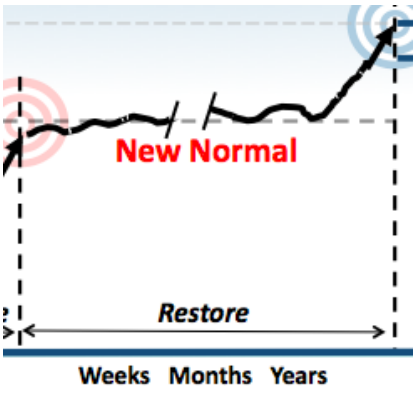



Some of the key issues that should be communicated with government authorities, especially with local and state/provincial emergency operations centers, include:

- Restoration assessment and prognosis
- Share needs and priorities
- Coordinate with other critical infrastructures
- Coordinate public announcements and schedules for voluntary and mandatory load shedding, including rotating blackouts
- Requests for protection and security

**Recommendation**: Entities should consider establishing crisis management teams that consist of broad stakeholder and technical representation and establish clear lines of communication with government. Similar to what many entities do during major weather events entities should consider co-locating at their state/provincial emergency operations centers 24/7 for as long as necessary.

## 9.4 Coordination and Communication During Restoration




Restoration and operation through the New Normal period will require scarce resources to be continuously reprioritized and reallocated. Government is ultimately the locus for determining public health and safety priorities for resource allocation, and as such, government authorities will need information about what supplies, resources, and materials are available, as well as the prospects and progress of restoration in order to make informed decisions.

Electricity entities in Canada and the U.S. have a long history of sharing resources and work crews to aid restoration following hurricanes and severe floods. In an effort to facilitate crossing the U.S. and Canadian border during emergencies, the Canadian Electricity Association is working with the Canadian Border Security Agency and the U.S. Department of Homeland Security. A *Cross-Border Mutual Aid Assistance Agreement* has been prepared and is expected to be implemented in the near future.

Government authorities and electricity entities should have primary, alternate, and possibly tertiary contacts and means of contact, including provisions for 24x7 contact. Hard-copy contact information lists should be maintained and reviewed at least annually.

Entities need to be familiar with government emergency management structures. For examples, entities in the U.S. should be familiar with the government's Incident Command System [ICS]/National Incident Management System [NIMS] principles[54]. Requests by entities should be referred through the appropriate channels.

**Continual Review of Legal Authority**: Legislation and supporting regulations define the role of government agencies during emergencies. Entities should be familiar with these and understand how emergency authorities may affect entity operations. During a Severe Event, government may revise these or enact new authorities. Entities will need to stay abreast of these changes, understand how they may affect the entity, and have mechanisms in place to communicate them quickly across the entity as appropriate.

**Understanding Impacts**: It is important for the government to understand the role played by BPS entities and vice versa. Requests for information should not distract or impede those who are engaged in operational roles such as restoration and crisis response. It is also important that government understand the actions that asset operators will be taking, and that actions will be underway independent of any emergency declaration by government. However, as the days add up to weeks after a Severe Event, decisions regarding changing priorities will be required.

[54] Ref. http://training.fema.gov/IS/NIMS.asp

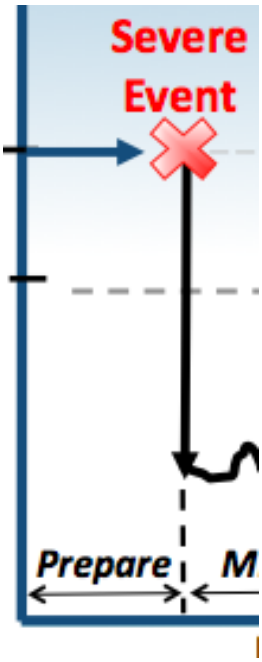
**Recommendation**: Government authorities and electricity entities should coordinate closely so they are prepared to explain the actions they are taking or are about to take, and why. Decision-makers will need to understand the second and third order effects of making such priority selections. For example:

- The sequence of electricity service restoration to consumers in different geographical areas or regions will vary depending on circumstances such as the availability of resources and the nature of any damages to equipment.
- If the cause of the Severe Event is continuing, restoration may need to be halted, or re-started.
- If fuel is not prioritized to communications facilities, the ability to operate portions of the BPS will be severely limited.

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# 10.0Taking Care of People




The electricity sector has extensive experience planning for emergencies. While these plans often focus on repairing or replacing physical assets and taking the necessary operating actions, success is highly dependent on our most important asset – knowledgeable, capable, and available personnel. Without question, a Severe Event will put great stresses on personnel throughout the New Normal period.

This section provides guidance on topics that should be included in an entity's disaster recovery plan or business continuity plan. Much of this information is based on past experience in disaster response operations and also includes lessons learned in everyday operations. While many of the suggestions might seem obvious, past experience indicates they may not be achievable if not planned in advance of an event. This guidance is provided in the context that can easily be modified for inclusion in entity plans.

This section discusses the following topics that should be considered as part of an entity's plans.

- Accommodation
- Safety considerations
- Employee and family Issues
- Respite facilities
- Counseling

## 10.1 Accommodation

Consider alternate housing arrangements that would be suitable during the Mitigation Phase as well as the longer Restoration Phase. Traditional support infrastructure such as hotels, restaurants, and grocery stores will most likely not be available or unable to support the influx of personnel and displaced residents of the affected areas.

An example of an extended restoration event is the recovery of Entergy's system after the catastrophic damage caused by Hurricane Katrina and the subsequent failure of the levy system around New Orleans. Because of its experience, Entergy modified its existing plans to include many of the recommendations provided in this section.

### Recommendations

Housing options could include rental housing, apartments, hotels, tent cities, campgrounds, employee travel trailers or campers, cruise ships or military vessels, and federal, state/ provincial shelter facilities. Identify points of contact to determine how these options would be acquired and implemented.

## 10.2 Safety Considerations

Maintaining operations through the New Normal period can be stressful and hazardous. There is never a good time for an accident or operating error, but this is especially true during a Severe Event. Paradoxically, experience has shown that safety rates can be better during major disaster response and restoration than during routine operations. This may in part be due to the initial increase in adrenalin and commitment to tasks that are of immense value to their peers and the general public. But it is not reasonable to assume that this will continue through the weeks or months of a Severe Event. The onset of fatigue and stress will contribute to increased errors. Accidents or operating errors can delay or even halt restoration efforts.

**Entergy's Experience from Hurricane Katrina**

Entergy's headquarters and nearly 1,000 employee homes were initially uninhabitable. Entergy secured office space to replace its New Orleans area work locations and arranged interim housing for displaced employees for 7 months. Entergy has since implemented long-term office relocations as an integral part of its disaster recovery strategy.

For entity incident and disaster planning, safety for personnel families and personnel performing operational restoration is a primary consideration. While many of these apply to "normal" emergencies, they can become particularly important during a Severe Event.

### Recommendations

- **Advanced warning** – If the Severe Event is preceded with advance warning, provide guidance on when and where to evacuate.
- **Proper permits** – Many entities require specific certifications and permits. Procedures should be documented on what permits and certifications may be waived through a Severe Event.
- **Safety teams to oversee work conditions** – Safety teams should monitor for signs of fatigue and stress and have the authority to stop work when conditions are unsafe. This may require an increased role for the entity's internal health and safety oversight organization.
- **Transportation** – Transporting personnel safely and reliably between work and rest centers will decrease stress.
- **Stock of supplies** – For shorter-term events, experts recommend having a minimum of a seven-day supply that will need to be adjusted for a Severe Event, but the same considerations for health and nutrition are applicable. Entities should consider stocking non-perishable foods and food in pouches; proteins, fruits and vegetables; and foods that do not require extra cooking and can be eaten cold if necessary. Store water, at least one gallon per person per day. Remember to have on-hand manual can openers, cooking utensils, pots and pans. Include aluminum foil, paper towels, garbage bags and disposable cleaning wipes. Have sufficient rotated stocks of batteries for flashlights and radios. Make up a good first aid kit and stock up on cleaning supplies, especially bleach, gloves and heavy-duty garbage bags. Keep freshly stocked emergency kits with vitamins and over-the counter medications that might be needed, such as pain relievers, antacids and cold-relief medications.

- **Notification of well-being** – Entities should provide communication options to allow personnel to contact family. Personnel should be patient as communication systems are likely to be disrupted. Typically, personnel will establish a family communication plan that establishes a time frame for contacting family after the event.
- **Encourage personnel to develop an individual or family Emergency Medication Plan** – Entities could develop and provide a sample plan to its employees. This may include the following:
  - Consult an individual's healthcare provider, especially for complicated or difficult-to-administer medications, such as those requiring pumps or nebulizers.
  - All medications should be kept in one location in the home, to expedite any evacuations or ease in retrieving medications after an event. Along with your prescription identification card, individuals should keep a list of their medications and those of other family members, including drug name, strength, dosage form and frequency.
  - If there is a shortage of medications for personnel, entities may consider helping to secure medications or work to have key personnel placed on a priority list for medications.
  - Keep the names and phone numbers of your doctor and the pharmacy that filled your prescriptions in your wallet. If possible, the entity should work with a local pharmacy or its mail-order service to help personnel address any prescription needs.
- **Personal protective equipment** – Ensure that an entity has and provides to field personnel the appropriate personal protective equipment.
- **Personnel in new roles** – When redirecting personnel into new roles which require more physical effort, leaders must take into consideration any health issues a staff member may have been able to control in under normal circumstances, but may be further exacerbated after a Severe Event.
- **Plan for medical response** – Enhance first-aid packs, and prepare for on-site medical care teams.
- **Worker rest** – Manage worker rest based on conditions and tasks. Ensure appropriate rest time between and during work shifts and provide safe, comfortable, and quiet facilities.
- **Security** – Provide security in areas where potential civil unrest may erupt that includes personnel guidance on how to manage such unrest.

## 10.3 Employee and Family Issues

Every employee and their family should have a personal emergency plan that recognizes and mitigates the risks faced in a given community. An entity's business continuity or disaster recovery plan should identify the relative criticality of each job function and inform employees potentially affected. As part of this planning, the entity should clearly communicate the level of support it will provide in situations covered by business continuity plans or disaster recovery plans so that employees in non-critical job functions may also plan appropriately. Employees who do not fill critical job functions should be instructed to check-in for reassignment.

During an event, health and safety concerns are a primary consideration. During a Severe Event, this concern extends to all personnel and their families. The success of restoration for an entity could hinge on whether the families of employees are safe and able to get back to some semblance of a normal set of activities.

### Operating Iraq's Grid in an Unstable Security Environment

With Iraq's unstable security situation and a shortage of system operators, generation, transmission and distribution station staff were expected to live on site. Given the high levels of sectarian and personal violence many families of staff were moved into the stations as well. Often the station staff would provide the residents surrounding the station with scarce electricity and create a friendly buffer around the station.

**Recommendations**

Some key topics that should be considered in disaster recovery plans that may need to be in place for months following a Severe Event include the following:

- Supplies and respite
- Communications
- Transportation
- Safety
- Education
- Child/elder care
- Secure homes
- Relocating employee's family to safety as necessary
- Food and necessities
- Continuity of pay and banking services

## 10.4 Respite Facilities

Immediately following a Severe Event, basic needs need to be met to help reduce personnel and family stress. Although the following recommendations appear to address the immediate need after a Severe Event, the human factor related to respite to prevent burn-out is something that will need to be addressed throughout the New Normal period.

**Recommendations**

**Rest Area**

- Provide an area that is covered and dry
- The area should contain heating and cooling with good ventilation
- Provide for personnel to sit or lie down
- Provide an area suitable for activities and discussions, and a separate quieter area for rest

**Water**

- Ensure personnel stay well hydrated.

### Respite Facilities following the 9/11 Terrorist Attacks

During the search and rescue and the subsequent clean-up at Ground Zero after the 9/11 terrorist attacks on New York, respite centers remained in the work-zone for an extended period of time.

- Reserve potable water for the essentials of drinking and food preparation. Other treated water may be suitable for showering and hand washing.
- Ensure water is treated and managed properly; serious diseases can be transmitted by untreated water.
- Properly dispose of or recirculate gray water to protect the potable water supply.

**Food**

- Ensure adequate supplies of healthy food. Consider long shelf-life foods, stock-piled in advance.
- Maintain clean and comfortable meal facilities.
- Store perishable foods below 45 ºF and serve heated food above 140 ºF.
- Dispose of perishable foods not properly stored after 4 hours.
- Consider weather conditions and temperatures to determine whether hot or cold foods should be served.

**Hygiene**

- Provide hand washing or disinfecting facilities at all food service areas, rest rooms, and disposal areas. Disinfecting and hand washing is the single-most important measure in preventing food-borne illness and must be enforced at all times.
- Provide individual hand cleansers and liquid hand sanitizing gel to personnel.
- Provide for bathing and clothes washing at respite facilities.

**Rest Rooms and Waste Disposal**

- Ensure portable latrines are available, cleaned regularly, and located in appropriate areas.
- Ensure waste is managed appropriately and designate storage locations away from living and work areas.

## 10.5 Counseling

Everyone involved in maintaining operations during an event are dealing with increased stress and anxiety. In certain events, there is a potential of the tragic loss of life and material possessions that will affect each person involved. Personnel must seek care from a stress management team or other options provided by the entity when they feel overwhelmed or unable to cope with maintaining operations. Many times during stressful situations personnel need someone to talk to that is not involved in the situation so they are not burdening their relationships with others close to them.

### Recommendations

During normal business operations, Human Resource (HR) departments usually have the responsibility of benefits that may include various types of counseling programs. HR may want to consider expanding their business continuity plan to include counseling programs for

incidents. An entity may consider establishing a counseling center at a respite location. Because situational stress and loss of life could include personnel (internal and external) and personnel's family members, the business continuity plan should establish a process to expand the needs of its typical employee assistance program to deal with needs of those individuals outside its organization. Remember personnel performance can be affected by the problems of an employee's immediate family members. In addition to the services provided by the entity, personnel may seek guidance from local religious leaders.

| **Key Recommendation #27 \|** Taking Care of People |
| --- |
| Consider ways to support the health, safety, and well-being of personnel and their families in the face of extraordinarily demanding circumstances. |

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# 11.0Logistics and Self Sustained Operations

This section identifies the challenges associated with the logistics of acquiring, delivering, and replacing or repairing assets damaged in a Severe Event and provides guidance on effective logistics to support operations through the New Normal period.

The key to identifying the best use of resources is dependent on the entity's ability to respond and think "outside the box" of normal planning for emergencies. Many of the items suggested are counter-intuitive to operating in a normal environment. Of necessity, many decisions will be spur of the moment decisions and may have un-intended consequences later as restoration progresses from the New Normal period to pre-event reliability. For example, suppose early in the restoration process a decision is made to cannibalize a substation for parts to rebuild other substations. As load continues to be restored over the New Normal time period, eventually the substation that was cannibalized will need to be rebuilt.

Decision-makers will need to understand the current operating situation and prioritize logistical needs in the absence of much of the information normally available. Initially, the efforts will focus on dispatching existing inventory to restore the critical loads essential to BPS restoration. Efforts will then rapidly shift to dispatching inventory to support priority loads, many of which will be on the distribution network.

Procurement processes suitable for normal operations to meet an entity's policies or government requirements may need to change to provide the flexibility and responsiveness needed during a Severe Event.

## 11.1 Specialized Equipment

Specialized equipment such as high voltage transformers, circuit breakers, turbines, phase shifters, and series capacitors often take a year or longer to procure and build. Consider the following:

- Participate in spare equipment consortiums that allow the use of other's spare inventory (e.g., NERC's Spare Equipment Database program[55]).
- Locate spare equipment at a site that is more secure than the sites where they may be needed.
- Develop agreements with other utilities to share spare or redundant equipment. If agreements already exist, discuss the implications of a Severe Event with the participating entities and consider how decisions would be made to appropriately allocate spare equipment. This is important because those owning the spare equipment will increase their operational risk by releasing spares.

[55] Ref. NERC Spare Equipment Database Task Force report http://www.nerc.com/filez/sedtf.html

- Maintain a list of suppliers and service level agreements for highly specialized installation or transportation equipment such as cranes for heavy equipment and Schnabel rail cars for large high voltage transformers.
- As opportunities arise to replace transformers that are aging or have insufficient capacity, convert substations operating at non-standard voltages to more common voltages.

## 11.2 Standard Equipment

While standard equipment such as structures, hardware, insulators, distribution components, etc. may be more readily available; replacement inventory will still be constrained. Consider the following:

- Compile a list of regional and national suppliers with around-the-clock contact information, and ensure the list is readily accessible during a Severe Event.
- Review existing spare equipment and material inventories under a Severe Event scenario and identify opportunities to improve these inventories.
- Create a salvage control center which could amass materials to be re-dispersed to key restoration areas. Cannibalize spare parts from damaged equipment or from less critical plants and substations.
- Siphon fuel from inoperable equipment.
- Re-allocate tools such as compressors, chargers, lifts from in-operable equipment.
- Re-allocate redundant equipment to facilities that need them.
- Use temporary design standards that use less material (e.g., wood and steel beams in lieu of concrete foundations, increase span distances between towers without sacrificing public safety).
- Remove obstacles from beneath transmission lines to increase clearance. Increase clear-cut corridors to manage vegetation growth with fewer resources.

### Wal-Mart and Home Depot Hurricane Response

Wal-Mart and Home Depot, valuable sources of many different consumables that may be required, have emergency response plans that have proven very effective during hurricane response.

## 11.3 Fuel for Transportation and Backup Generators

Entities have contracts in place with suppliers to provide fuel for vehicles and generators. However, during a Severe Event the fuel suppliers may also be impacted and normally used delivery systems or routes may be unavailable. Entities should enhance their arrangements with suppliers in advance of a Severe Event to consider alternative delivery systems. Regardless, entities need to consider how they would prioritize their allocation of limited fuel supplies.

**Table 6: Sample Fuel Priorities for Critical Equipment**

| Critical Load | Rationale for Priority |
|---|---|
| **Backup generators at nuclear stations** | In the event of a loss of BPS power supply, enhance recovery, prevent extended unavailability, or maintain safe shutdown |
| **Backup generators at non-nuclear generating stations** | In the event of a loss of BPS power supply, enhance recovery and prevent extended unavailability |
| **Backup generators at transmission substations** | Supply station service auxiliaries (e.g., compressed air for breaker operation, protection systems, station monitoring devices and systems) |
| **Backup generators power plant and system control centers** | Supply critical operations at Reliability Coordinators, Transmission Operators, Generator Operators |
| **Backup generators at telecommunications centers** | Supply communications facilities and systems needed to operate the BPS |
| **Vehicles** | Transport personnel and resources needed for BPS restoration and supply to critical loads and priority loads |

| **Key Recommendation #28 \|** Logistics and Self-Sustained Operations |
|---|
| Consider with fuel suppliers ways to prioritize the supply and delivery of fuel for emergency standby generators and essential work vehicles. |

## 11.4 Transportation Routes

Evaluate alternative transportation routes. It is likely that the transportation sector (e.g., airlines) would be heavily impacted. This occurred with September 11th and with recent volcano eruptions shutting down air traffic into Europe, South America, Australia, and New Zealand. Natural disasters combined with terrorist activity could easily impact the railroad or highway system to large parts of the continent.

Seasonal issues such as ice storms, blizzards, hurricanes, and flooding can compound the impact of the Severe Event on transportation. Consider alternate transportation modes (e.g., rail, air, water, truck) that may not be appropriate during normal circumstances.

Establish contact with and develop relationships with state and local government transportation authorities who can help identify transportation routes and approve any transportation permits that may be required by utilities, transportation service-providers, or mutual assistance partners.

## 11.5 Personnel and Facility Resources

Whether using entity employees or external resources, a Severe Event will strain the entity's ability to respond to a Severe Event. Planning to effectively use human resources during a Severe Event will optimize the utility's ability to respond.

### Entity Employees

Business continuity and disaster recovery plans should identify the key personnel needed to restore and maintain critical operations, and recognize the increased intensity associated with filling these roles through the New Normal period. Plans should address scheduling additional personnel to assume these critical roles or provide operational support. Plans should address issues related individuals who are unwilling or unable to report for work. The plans should also consider how to supplement these key roles with personnel who can be shifted from lower priority work and quickly trained to fill critical roles. For every critical role, there should be at least one individual with primary responsibility and a fully trained and experienced backup. Identify, train, and explicitly recognize individuals to fill these roles.

Plans should identity the initial work shift hours and team or crew composition. For example, during the first few days of an event shift durations may be different than later in the event when circumstances may be more predictable. Consider changes that may be required to employee work arrangements (e.g., collective agreements) such as work schedules and alternate roles and responsibilities.

- **Management Personnel** – Management will need to be ready to make important decisions to support personnel operating in unusual situations, including working out of their normal scope of responsibilities or levels of authority.
  - With the necessary refresher or certification training, a manager with experience in the field and technical trades could assist as an equipment operator, control center operator, or foreman.
- **Field Personnel** – Field personnel will play front-line operational roles to identify damage and repair or replace damaged equipment.

  - With suitable training, a groundman may perform certain duties as a line hand on a de-energized line.
  - Journeymen linemen may provide support in roles such as relay technician assistants or substation assistants.
  - Warehouse staff may provide groundman support for line crews.
- **Operating Personnel** – Operating personnel are typically the first to recognize an event has occurred and are instrumental in activating their entity's plans. They will need to maintain situational awareness, make decisions and direct operations clearly and concisely at all times.
  - Back office engineering staff may support system operator functions.
- **Office Personnel** – Office personnel will not likely be directly involved in the front-line of restoration activities, yet the most important aspects of their roles will still need to be carried out and they may be re-deployed to new tasks.
  - Engineering or office staff may fill needed roles in logistical operations such as procurement or warehousing.

### Leadership and Succession Planning

During a Severe Event, it is particularly important that personnel know at all times the manager or supervisor who will provide them with direction and operational support. Circumstances will require these leaders to change roles through the New Normal period, and succession planning will be a critical element of an entity's strategic direction and operational success. It is vital that leaders at all levels continue to find, assess, develop, and monitor the personnel resources needed to manage New Normal conditions. As the New Normal period progresses, working conditions may become more stable, and entity leaders may resist losing competent personnel to other roles, and having to train their replacements. Leaders themselves may be reluctant to move into new areas of responsibility. Leaders need to understand that succession planning must continue to match rapidly evolving organizational needs with employee competencies and capabilities. Effective succession planning will form the basis for continued success through the New Normal period. The succession planning process for the organization should:

- Define the skills and competencies needed through the New Normal period.
- Identify leadership and personnel competency gaps.
- Observe and periodically assess how leaders and personnel are coping in their roles.
- Identify personnel who are demonstrating an ability to assume increased responsibilities.
- Foster a growing sense of responsibility for personnel to display leadership characteristics at all levels in the organization.

### Clearly Define the New Roles

It is important that personnel understand their new roles and who their manager or supervisor is at all times. Personnel need to know who provides them with technical direction and who they can rely on when they need to seek help or advice. Personnel roles and responsibilities should be clearly defined and documented and include:

- **Reporting structure** – present and new role, new work locations, new manager or supervisor, working hours and shifts
- **Expectations of the new role** – personal equipment provided by the individual (e.g., tools, personal protective equipment), equipment that will be provided at the work location, professional qualifications, certifications, or licenses required.

### External Resources (Contractors, Mutual-Aid providers)

Entities often rely on externally contracted resources to fill roles similar to those of entity employees, for example for major projects. Entities need to consider that these contracted resources may not be available during a Severe Event, as other entities will have similar incremental needs to respond to the Severe Event. Prior to a Severe Event, entities should consider establishing contracts with these resources that explicitly address what may or may not be provided through a Severe Event (e.g., force majeure).

Mutual aid arrangements with other entities allow entities to quickly supplement their existing workforce. Recognizing that neighboring entities may be similarly stressed, consider making arrangements with a number of geographically dispersed entities to help ensure that assistance can be obtained from areas outside the affected region. Similarly, consider how you may be able to assist other entities, particularly with personnel other than the work crews historically familiar with working in new work locations (e.g., system operators, system planners, control room support staff). The terms of these arrangements should be reviewed periodically.

| **Key Recommendation #29 \|** Logistics and Self-Sustained Operations |
| --- |
| Consider how your business continuity or disaster recovery plan would change if you are unable to rely on mutual support arrangements. |

### Alternate Work Locations

During a Severe Event, it is possible that the primary work location may be unavailable and personnel will need to work from backup or other temporary locations. Personnel should be trained on how to deploy to the alternate location and start work safely and efficiently.

Alternate work locations, which may include fields for staging work, empty warehouses, or schools should be identified and tested periodically. Plans should consider:

- Alternate backup facilities if both primary and backup operations centers are unavailable.
- A communications plan to quickly and reliably direct personnel to backup facilities.
- Van pools to safely transport employees and conserve fuel.
- If working from home is viable, ensure personnel have the tools to effectively work prior to any event.

# 12.0 Preventing and Responding to Physical Attacks

While this report provides generally applicable guidance for entities to prepare, mitigate, and respond regardless of the cause of the Severe Event, this section specifically addresses a coordinated physical attack scenario.

It is impossible to completely prevent a determined physical attack on BPS infrastructure. However, steps can and should be taken to prepare to make such an attack more difficult and/or less effective.

This section discusses the following topics:

- **Challenges** – The challenges of preventing and preparing for physical attacks.
- **Prevention** – Steps that should be considered to protect facilities in a way that will discourage attacks, make attacks more difficult to accomplish, or minimize the damage.
- **Preparation** – Steps that should be considered in advance, to prepare to respond to a physical attack.
- **Response and Recovery** – Steps that should be considered to effectively respond to a physical attack, and how security might change to support operations through the New Normal.

### Assumptions

This section assumes the following scenario:

- A simultaneous and coordinated physical attack directly impacts the BPS. Equipment at multiple generating stations and high voltage transmission substations are severely damaged.
- Subsequent attacks days or weeks later will continue to impact BPS equipment and place field personnel at risk. Law enforcement and National Guard support to protect field personnel and equipment is very limited due to the priority to protect the communities they serve.
- Voice and data communications are disrupted due to equipment damage (microwave towers, fiber cuts, etc.). Cell phone systems are jammed due to excess traffic.
- Transportation is disrupted due to widespread power outages.

## 12.1 Challenges to Protecting the BPS

In order to provide some insight into why some prevention and preparation strategies are suggested and others are not, the following provides context for subsequent sections.

### Asset Protection

BPS assets are dispersed widely across the continent, usually in remote areas, making complete protection infeasible. Protection is often limited to fencing and padlocks at facilities that are operated remotely and not staffed.

### Mixed Environments

Some BPS assets are in rural, remote locations while others are in urban, densely populated areas. This makes protection difficult and the resulting procedures complex.

### Multi-Jurisdictional

Because service territories rarely align within a single municipality, it is typical for entities to need to deal with many different local law enforcement agencies to address security issues. This multi-jurisdictional nature is not limited to the geographic location of the assets, but also involves understanding the various different government agencies and their roles.

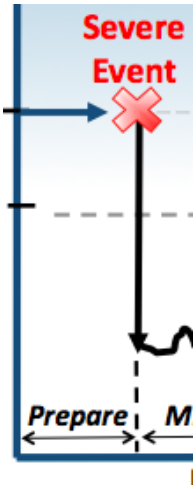
### Replacement Assets

Many BPS assets are difficult to replace or repair – some require purchasing lead-time of many months. This suggests that greater protection is needed for these assets.

### Ease of Asset Identification

Due to the size, accessibility, and visibility of high voltage power lines, identifying equipment that is part of the BPS is relatively easy.

## 12.2 Recommended Prevention Strategies




While it is impossible to completely prevent a determined physical attack on BPS infrastructure, actions should be considered to implement prevention measures that will deter or limit an attack by making it difficult to locate, enter, and damage a facility.

### Obfuscation

A facility that 'blends' into its surroundings is more difficult to identify and decreases the chance it will be targeted. This can be accomplished by:

- **Security by Environmental Design** – Where possible, establish visual barriers such as trees, mounds, and bushes.
- **Security by Architectural Design** – Where possible, use matching building material that blends the asset into the neighboring buildings.
- **Fly Zones** – Do NOT identify locations as 'no fly zones' to the Federal Aviation Administration and Transport Canada. The resulting maps available to all pilots are widely published and will clearly identify the location of the facilities.

### Hardened Facilities

Design facilities, particularly those that are critical assets, to increase the effort required to damage the facility or make it difficult to gain access. Install equipment to detect and report a security breach. This can be accomplished using:

- Basic construction techniques, such as:
  - Higher and stronger walls
  - Fewer windows and doors
  - Reinforced gates
- Install monitoring and sensing equipment, such as:
  - Cameras
  - Vibration Detection
  - Motion Detection
- Involve the local community, for example by enhancing Neighborhood Watch programs to raise awareness regarding the local BPS facilities that they rely on.

| **Key Recommendation #30 \|** Preventing and Responding to Physical Attacks |
|---|
| Consider actions that can be taken to protect BPS assets by involving local communities and law enforcement (e.g., reinforcing their awareness of BPS facilities that are critical to operations). |

| **Key Recommendation #31 \|** Preventing and Responding to Physical Attacks |
|---|
| Consider ways to improve security when designing or refurbishing existing BPS facilities. |

## 12.3 Recommended Preparation Strategies

The strategies suggested in this section pertain to preparatory actions that may be taken prior to an attack to manage likely consequences. These actions will help ensure that assets are prioritized, vulnerabilities and risks are understood, law enforcement support is coordinated, and plans and teams have been developed and exercised.

### Consequence Assessments

Consider conducting consequence assessments to evaluate and prioritize BPS assets. Consequence assessments should consider the impact on the entity, as well as impacts on society and other critical infrastructures within the entities footprint of operation. Criteria to identify critical assets for NERC Reliability Standard CIP-002-1 are provided in the *NERC Security*

*Guideline – Identifying Critical Assets*[56]. Additional information is available in Section 3 of the DHS National Infrastructure Protection Plan[57] that provides a generic methodology for consequence assessments.

### Physical Vulnerability Assessments

Conduct physical vulnerability assessments to identify threats, vulnerabilities, loss impacts, prioritize risks, and identify cost effective controls. Assume that critical assets will be targeted.

### Strategies

Identify strategies for emergency response, operations recovery, and system restoration.

### Site Security Plans

Develop, exercise and maintain site security plans that provide for the protection of assets and personnel from physical attacks. Site security plans should be based on the results of consequence assessments as well as risk and vulnerability assessments. The countermeasures documented in the plans should be implemented according to the alert levels declared by the entity.

### Emergency Response Plans

Develop, exercise, and maintain incident and emergency response plans that provide for life safety (e.g., evacuation, shelter-in-place, bomb threat) and limit initial property damage.

### Business Continuity Plans

Develop, exercise, and maintain business continuity plans that initially recover business operations to minimally acceptable levels for the New Normal period, then later resume operations to normal business operation levels.

### Incident Management Plan

Develop, exercise, and maintain an incident management plan that addresses command, control, communications, and coordination with entity operational response, crisis communication (e.g., media, consumers), and government.

### Training

Train and exercise teams in the activation and execution of the above plans and other response, recovery, and restoration strategies.

### Local Law Enforcement Agency Days

Collaborate with local law enforcement agencies to build relationships. Foster an environment of cooperation and participate in joint exercises. Coordinate planning and preparedness activities with local and state/provincial government.

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[56] NERC Security Guideline – Identifying Critical Assets
http://www.nerc.com/fileUploads/File/Standards/Critcal_Asset_Identification_2009Nov19.pdf

[57] Ref. NIPP, National Infrastructure Protection Plan

| **Key Recommendation #32 \|** Preventing and Responding to Physical Attacks |
|---|
| Consider ways to improve local coordination and cooperation with local/state/provincial law enforcement. |

### Replacement Equipment

Essential equipment that is difficult to obtain should be identified, acquired, and stored in secure locations. See the *Logistics and Self-sustained Operations* section of this report for additional information.

### Adaptability and Continuous Improvement

Periodically perform post-exercise reviews to identify and document preparedness successes, areas for improvement, and lessons-learned. Develop an action plan for improvements, develop enhancements, and implement identified improvements.

### Possible Threats

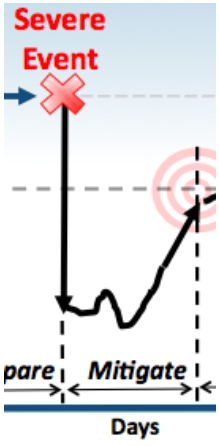
Physical attacks on the BPS may appear in several forms. Threats could come from internal (e.g., disgruntled employee, contractors) or external (e.g., disgruntled customer, terrorist) sources. The table below shows possible threats that should be considered when performing a risk assessment. The threats shown could be part of the initial attack or could be part of subsequent attacks designed to stop, slow, or divert response and recovery efforts.

### Controls Overview

Controls (countermeasures, safeguards) may come in many forms. Before an appropriate control can be identified the nature of the threat must be understood as well as the vulnerability of the asset being protected. Threat and vulnerability information is identified and documented in a risk assessment. When assessing controls it is useful to classify them into 'control types'. The table below shows possible controls separated into control types. The examples shown are not limited to a physical attack scenario.

| Table 7: Control Types and Examples | | |
|---|---|---|
| **Control Type** | **Definition** | **Control Examples** |
| **Prepare** | Controls that prepare for threat occurrence or expected losses. | Risk assessments, impact assessments, plans (response, recovery, restoration, preparedness), backup data, alternate sites, backup equipment, awareness, training, exercises, drills, control maintenance |
| **Prevent** | Controls that prevent threat occurrence or resulting losses. | Prevention procedures, site security plans, fences, access control, passwords, safety measures, fire prevention measures, hide asset, security guards |
| **Detect** | Controls that detect threat occurrence or resulting losses. | Smoke detectors, heat detectors, motion sensors, vibration sensors, cameras, security guards |
| **Minimize** | Controls that reduce or minimize losses as the threat occurs. | Activate emergency response procedures, water sprinklers, CO2, halon, fire extinguishers, exit signs, stairwells, emergency lighting, first-aid kits, flood wall, deterrence measures, security guards, backup generators |
| **Recover** | Controls that recover resources, operations, and reputation lost as a result of threat occurrence. | Activate business recovery and restoration procedures, heal/replace injured personnel, rebuild/replace damaged equipment and facilities, restore data from backups |

## 12.4 Recommendations for Response and Mitigation Strategies




The strategies suggested in this section pertain to actions taken immediately after the physical attack to notify appropriate response teams, assess the nature and magnitude of the attack, and review the status of BPS assets in order to make decisions on the physical security and incident management actions to be implemented.

### Site Security Plans

Activate appropriate site security plans according to the alert levels (e.g., Elevated, Imminent per U.S. National Terrorism Advisory System[58]) to protect critical assets and personnel from additional attacks.

### Emergency Response Plans

Activate appropriate emergency response plans (evacuation, shelter-in-place, bomb, threat, etc.) that provide for life safety and limit initial property damage.

### Business Continuity Plans

Activate appropriate business continuity plans that recover time-sensitive, high priority business operations to minimally acceptable levels for the New Normal period.

### Incident Management

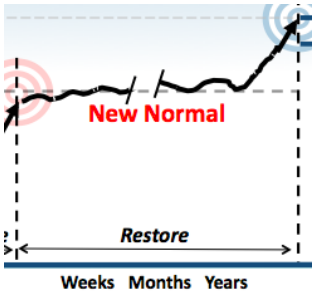
Activate an incident management system that includes the execution of crisis management plans, the activation of emergency operations centers and incident command posts, as well as the coordination of emergency response and business continuity. Also, activate crisis communication plans, and coordination with government and industry authorities.

Additional response actions are shown in the Mitigations for Physical Attack section in *Appendix 3* of this report.

[58] Ref. NTAS http://www.dhs.gov/files/publications/ntas-public-guide.shtm

## 12.5 Recommendations for Restoration Strategies

The strategies suggested in this section pertain to actions that should be taken after response actions are underway to notify appropriate recovery and restoration personnel, implement the incident management system, recover business operations according to prioritized lists of BPS assets, and implement physical security plans and procedures.




### Site Security Plans

Continue implementation of site security plans according to the alert levels (e.g., Elevated, Imminent per U.S. National Terrorism Advisory System[59]) to protect critical assets and field personnel from additional attacks.

### Business Continuity Plans

Continue implementation of business continuity plans that recover time-sensitive, high priority business operations. Activate plans to recover less time sensitive, lower priority business operations to minimally acceptable levels. Later, resume operations to normal business operation levels.

### Incident Management

Operate an incident management system where crisis management teams in emergency operations centers and incident command teams in the field provide command, control and coordination of restoration activities, communication, physical security, and coordination with government and industry authorities.

### Adaptability and Continuous Improvement

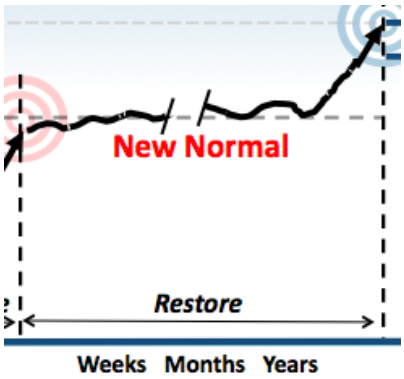
Perform after action reviews to identify and document successes, failures, and lessons-learned. Develop an action plan for improvements; follow the action plan, and implement actions to improve preparation, response, and restoration plans and procedures. Share non-proprietary after action review results with NERC, as appropriate.

Additional restoration actions are shown in the *Mitigations for Physical Attack* section in *Appendix 3* of this report.

[59] Ref. NTAS http://www.dhs.gov/files/publications/ntas-public-guide.shtm

# 13.0Financing Emergency Operations

During a routine emergency and recovery (e.g., storm damage), entities normally have sufficient cash and related financial mechanisms in the form of reserves, lines of credit or other financial instruments to deal with immediate needs. Consumer rates approved through the tariff approval process and various forms of industrial insurance are used to finance restoration work and the return to normal operations is possible through rate recovery. A more serious event[60] can be financially devastating.




A Severe Event will certainly have financial impacts that exceed anything that North America has experienced. The recent nuclear tragedy in Japan hints at the seriousness of the potential problem. This is a look into crippling financial problems as severe as the event itself.

The requirement for cash immediately after the event and for months during recovery through the New Normal period will be significant. Conservative estimates may place this cash requirement at ten times that of normal operations. Given this cash flow requirement, the duration of liquidity is short lived. An entity's ability to acquire and properly allocate funds will largely influence the degree to which recovery is successful, or even possible. Effective cost-tracking and audit processes will still need to be in place to demonstrate that restoration actions are financially prudent under the circumstances.

Each entity will react somewhat differently to the financial reality of a Severe Event depending on the financial structure of the entity and cash flows and lines of credit diminish. State/provincial and federal intervention will be inevitable during a Severe Event.

The goal of this section is to provide guidance and information to all entities faced with these financial challenges under the following assumptions.

- The Severe Event is regional and affects several BPS entities
- Existing banking and insurance institutions are still functioning, but are outside the area affected by the Severe Event.
- The entity's executive and financial functions are able to operate.

[60] Ref. Edison Electric Institute, *After the Disaster: Utility Restoration Cost Recovery* http://www.eei.org/ourissues/electricitydistribution/Documents/Utility_Restoration_Cost_Recovery.pdf

## 13.1 Getting Prepared for Emergency Financing

Some would argue there is little that can be done in advance to prepare for emergency financing that would be required through a Severe Event. Increasing consumer electricity rates through the normal tariff and regulatory approval process would be extremely difficult if not impossible. The carrying cost for large lines of credit is similarly difficult to secure and would soon become unsustainable. It is expected that the need to manage costs will place increased pressures on everything from staffing levels to warehouse inventories and reduce bench strength of needed equipment and resources.

However, much can be done to prepare to manage the financial pressures that would arise soon after a Severe Event. Entities should consider bringing together those responsible for financial matters to discuss the issue. The insurance, procurement, risk management, and financial functions share a significant part of the responsibility and may already have much of the information needed to prepare a plan. Discussions with suppliers, financial institutions, and labor unions will increase awareness of the challenges that would be faced in a Severe Event, and help identify options to address them.

| **Key Recommendation #33 \|** Emergency Financing |
|---|
| Consider how extreme financial challenges will be addressed in consultation with financial institutions, suppliers, and government agencies. |

The following links provide references that may aid these discussions.

**Public Safety Canada:** http://www.publicsafety.gc.ca/prg/em/index-eng.aspx

- Resources for Emergency Management Planning
  - Emergency Management Planning Guide to support the Federal Policy for Emergency Management and the Emergency Management Act (2007)
  - All-Hazards Risk Assessment
- Emergency Preparedness
  - Canadian Emergency Management College
  - Guides for business and first responders
  - Joint Emergency Preparedness Program
- Joint Emergency Preparedness Program (JEPP) http://www.publicsafety.gc.ca/prg/em/jepp/index-eng.aspx

**Canadian Centre for Emergency Preparedness:** http://www.ccep.ca/

**U.S. Federal Emergency Management Agency (FEMA):** http://www.fema.gov/privatesector/preparedness/

- References, news and information

- Robert T. Stafford Relief and Emergency Assistance Act
  http://www.fema.gov/pdf/about/stafford_act.pdf

**U.S. Department of Energy:** http://www.oe.energy.gov/our_organization/iser.htm and http://energy.gov/oe/office-electricity-delivery-and-energy-reliability

**University of Florida:** http://disaster.ifas.ufl.edu/PDFS/CHAP03/D03-07.PDF

- Outlines the role of U.S. government agencies in a disaster
  - Describes the difference between a Declaration of an Emergency and a Declaration of a Major Disaster
  - Outlines the types of assistance that a state governor may request
  - Describes the role of FEMA if engaged

**New York University, International Center for Enterprise Preparedness**:
http://www.nyu.edu/intercep/businesscase/index.html

- Provides links to research papers on the financial impacts of emergency preparedness:
  - Corporate balance sheet, impact on assets and liabilities
  - Profit and loss, impact on revenue and expenses

**U.S. Emergency Management Assistance Compact**: http://www.emacweb.org/

- State-to-state mutual aid system

**Public Entity Risk Institute:**
https://www.riskinstitute.org/peri/index.php?option=com_bookmarks&task=detail&id=588

# Appendix 1: Task Force Scope

## Purpose

This document defines the scope, objectives, organization, deliverables, and overall approach for the SIRTF.

The purpose of the SIRTF is to provide guidance and options to enhance the resilience of the bulk power system to withstand and recover from severe-impact scenarios, specifically:

- Coordinated physical attack
- Coordinated cyber attack
- Geomagnetic disturbance

## Background

The NERC and DOE *High Impact, Low Frequency Risk to the North American Bulk Power System* report described a number of severe-impact scenarios and their potential impact on the reliability of the bulk power system. Subsequent to this report, the Electricity Sub-sector Coordinating Council's (ESCC) *Critical Infrastructure Strategic Roadmap* identified a number of strategic initiatives to mitigate these impacts. Several of these initiatives (i.e., items E, F, H, L, and P) identify the need to assess the current capability of the bulk power system to withstand these severe-impact scenarios and to enhance restoration plans and procedures.

NERC staff and the leadership of the NERC technical committees (Planning, Operating, and Critical Infrastructure Protection Committees) have developed a Coordinated Action Plan to address the initiatives identified in the Strategic Roadmap. This scope document elaborates on the Coordinated Action Plan to establish and provide direction to the SIRTF.

## Scope

The SIRTF will provide guidance and options to enhance the resilience of the bulk power system to withstand and recover from three severe-impact events as described in the Coordinated Action Plan.

- Coordinated physical attack
- Coordinated cyber attack
- Geomagnetic disturbance

The SIRTF will propose approaches, practices, and plans to reduce the impact of these events through effective emergency operations and timely restoration of the BPS.

The SIRTF will consider what aspects of emergency operation and restoration will be particularly challenged through these severe-impact events, and consider options to enhance the resilience of the BPS. Preferred solutions will be flexible and based on heuristic methods applicable under a wide variety of circumstances, as opposed to fixed procedures. The SIRTF will recommend solutions for broad implementation across the electricity sector, and propose drills or exercises to reinforce this capability. These solutions could be in the form of industry

guidelines that describe practices that may be used by individual entities according to local circumstances.

The SIRTF may consider establishing sub-teams to address the planning /operational and tools/systems issues that may be unique for each of the three severe-impact scenarios.

### Assumptions and Limitations

The three scenarios described in the Coordinated Action Plan are intended to describe extreme conditions that would make operation and restoration much more challenging than would normally be considered by electricity entities through their usual planning and preparedness activities. While solutions that offer material improvements are preferred, it is recognized that more modest enhancements that are readily implemented are also valued.

It is expected that any solutions proposed to enhance existing capabilities would be broadly applicable to other severe-impact scenarios, and certainly applicable to smaller scale events.

### Goals and Objectives

| Goals | Objectives |
|---|---|
| Review current situation and capabilities | 1. Recognizing that priorities will vary depending on local circumstances, consider priorities to restore critical power system loads along restoration paths (e.g., communications, nuclear units), and priority customer loads (e.g. oil refineries, military bases, hospitals, water treatment plants, public telecommunications). Consider how these priorities might differ through a range of outage durations (e.g., days, weeks, and longer).<br>2. Consider operating capabilities and voice and data communications tools and energy management systems, with a focus on identifying minimum essential functional needs for reliable operation.<br>3. Consider restoration plan elements such as blackstart, islanded operation, synchronization, rotational load shedding.<br>4. Assess operational staffing levels and unique safety considerations under these scenarios. |
| Perform needs assessment | 5. Identify elements of current operating and restoration capability that would be particularly challenged under these severe-impact scenarios. |
| Develop alternative solutions | 6. Propose a range of alternative solutions and options to enhance current operating and restoration capability, including estimated costs and effort to develop and maintain this capability. Identify the residual risks that may be associated with each of these solutions. |

| | |
|---|---|
| Coordinate Solutions | 7. Coordinate with NERC staff to integrate these solutions with the NERC Crisis Response Plan with special emphasis on areas where local, state, and Federal resources may be required to support such efforts. |
| Recommend solutions | 8. Recommend specific practices or programs for use by NERC or individual entities. Create scalable drill templates that registered entities could be used to train personnel and enhance current restoration and operating protocols through existing drill and exercise programs. |

### Task Force Reporting Structure and Coordination with Other Related Initiatives

The Task Force will:

- Report to the Operating Committee. Seek Planning Committee endorsement prior to Operating Committee approvals.
- Provide periodic status reports to the Operating Committee and Electricity Sub-Sector Coordinating Council
- Coordinate closely with the Critical Infrastructure Protection Committee that will provide expertise to address Coordinated Action Plan Item F – Protect Critical Equipment
- Coordinate closely with the Spare Equipment Database Task Force
- Coordinate with other NERC and industry resources that may be able to contribute, such as the, Reliability Coordinator Working Group, North American Transmission Forum
- Leverage from other recent initiatives in this area (e.g., the National Infrastructure Advisory Council's Stress Test exercise)

### Resources Required

The Task Force requires expertise in the following areas:

- Experience with the real time operation of the bulk power system, including the communications and energy management systems and tools typically used by reliability coordinators, transmission operators, and generator operators.
- In-depth experience with bulk power system restoration plans and procedures, including designing and conducting restoration drills and exercises.
- Familiarity with developing situation assessment reports used to inform senior management or government.

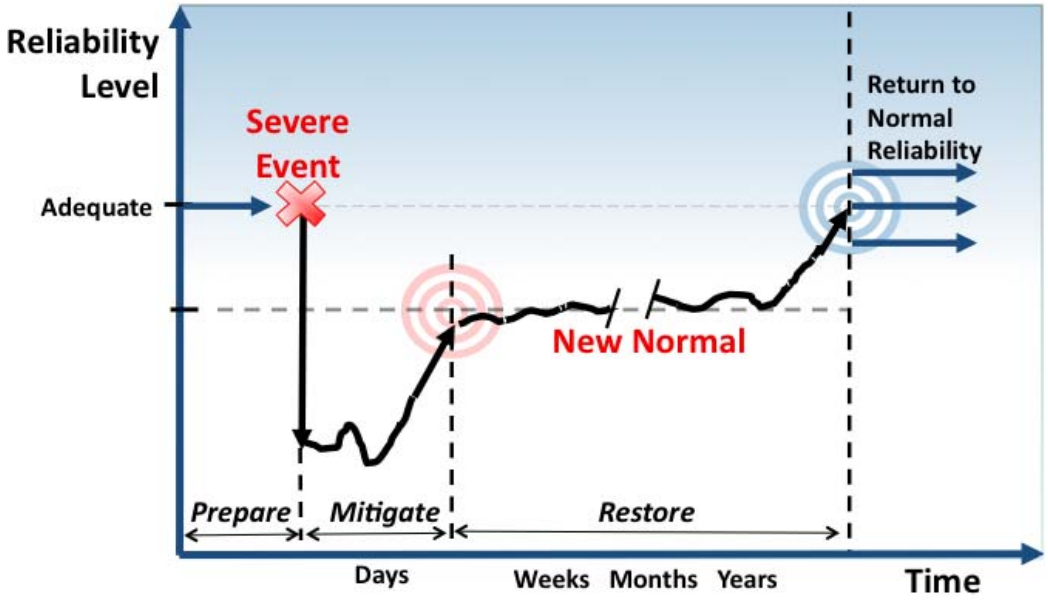
It is anticipated that 2 conference calls per month, and a total of 4 face-to-face meetings will be required, in addition to the time required to contribute to this effort. This work is expected to begin in December 2010 and end by December 2011.

## References

| Name | Link |
|---|---|
| DOE/NERC HILF "*High Impact, Low Frequency Risk to the North American Bulk Power System*" report | http://www.nerc.com/files/HILF.pdf |
| *Critical Infrastructure Strategic Roadmap* | http://www.nerc.com/docs/escc/ESCC_Critical_Infrastructure_Strategic_Roadmap.pdf |
| NERC Technical Committees' Report – *Critical Infrastructure Strategic Initiatives Coordinated Action Plan* | http://www.nerc.com/docs/ciscap/Critical_Infrastructure_Strategic_Initiatives_Coordinated_Action_Plan_BOT_Apprd_11-2010.pdf |

# Appendix 2: Mitigations for Monitoring the BPS

This Appendix builds on the recommendations in the *Monitoring the BPS* section of this report and highlights the different actions that may be taken, prior to, during, and after a Severe Event.




| MONITORING Resilience Considerations | | Preparedness: Prior to Event | Mitigation: During an Event | Recovery: After an Event |
|---|---|---|---|---|
| | | **Robustness** The ability to absorb shocks and keep operating | **Resourcefulness** The ability to manage a disruption as it unfolds | **Rapid Recovery** The ability to get back to Normal as quickly as possible |
| **Generator Output** | | | | |
| 1. | **Fixed Schedules** | | Develop and Modify as required MW and MVAR output schedules of available units | As the situation becomes more stable the variability and flexibility of the schedules will be broader. |
| 2. | **Block Loading** | | Using a block loading schedule reduce the need for communications | |

| | MONITORING Resilience | Preparedness: Prior to Event | Mitigation: During an Event | Recovery: After an Event |
|---|---|---|---|---|
| 3. | **Operating Ranges** | Review with GOP's particular operating ranges that if a directive is outside of the GOP needs to confirm the directive with its own call | Within the response and New Normal adjust and communicate new ranges as required by the new system. | |
| | **LIMITS** | | | |
| 4. | **Hard Copies of Limits** | On a periodic basis print out BPS limits and maintain copies in primary and back-up control centers | During a cyber event routinely sample displayed limits with printed limits | |
| 5. | **Referencing Guides** | Consider developing distribution factor spreadsheets that act as quick references to better understand the effects of possible actions and contingencies | After an event and particularly in islanded operations and when PSSE tools are not available these tables may need to be recalculated. | |
| 6. | **Standing Orders and Temperature Sets** | Consider a standing order which states following an event to ease communications particular triggers will be used to go from one temperature set to another. | Based on communications capabilities may want to go to a seasonal set of ratings – making it easier to ensure all parties are always using the same set of ratings | |
| 7. | **Conservative Limits** | Define a conservative set of limits which could be implemented after a large event (could be as simple as a percent back-off) | | As the system becomes more stable and operators will need to continually reassess if these limits are too conservative for the community's needs. |

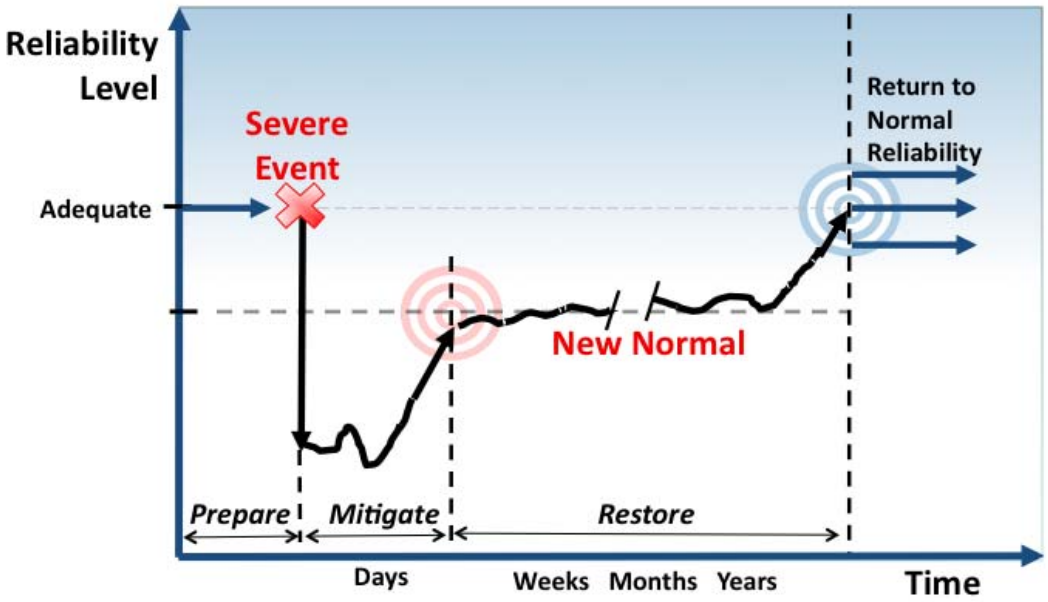
| | MONITORING Resilience | Preparedness: Prior to Event | Mitigation: During an Event | Recovery: After an Event |
|---|---|---|---|---|
| 8. | **Revisit Design Assumptions** | | A continual re-assessment and implementation cycle of adjusting operating limits to the realities of the current topology and not the original design assumptions. As islands are interconnected these differing operating assumptions will need to be communicated to the joining entities. | |
| 9. | **Operate to the Most Conservative Limit** | Have discussions with operators and engineers when operating to the most conservative reading may not be in the best interest of reliability. | Continually work with other critical infrastructures to determine whether operating to a less conservative rating is in the greater good of keeping multiple critical infrastructures available. | |
| | **MONITORED FLOWS ON BPS FACILITIES** | | | |
| 10. | **Prepare for Large Amounts of Data Loss** | 1. Conduct studies of the minimum amount of data needed.<br>2. Assess how greater aggregation might reduce some of the reliance on this data.<br>3. Develop practices for operating without any SE/SA capability for months.<br>4. Develop a list of the most critical data points. | Based upon the list of most critical data points prioritize which stations will be staffed with the communications available at that time. | Train additional personnel to assist in the 24/7 needs to report data. |
| 11. | **Loss of Primary & Back-Up EMS** | Understand which portions of your system are independently monitored by neighbors. | Consider how off-line study packages and applications (operator training simulator) could be leveraged. | |

| | MONITORING Resilience | Preparedness: Prior to Event | Mitigation: During an Event | Recovery: After an Event |
|---|---|---|---|---|
| 12. | **Phasors** | Continue to develop the operational capabilities of the PMUs. As these capabilities and systems are developed, consider keeping their data feeds and platforms independent of EMS capabilities. | 1. Redefine the operating parameters of the PMU applications as procedures/decision points may be based upon pre-crisis topology.<br>2. Continue to evolve operating procedures around operating experience. | |
| **Loss of Both Control Centers** | | | | |
| 13. | **Back Up Location Considerations** | Consider both sites are sufficiently distant so as not to be affected by single events which would render a control center unusable. | Backup sites should have considered the issues of personnel feeding, hygiene, security, backup power, and transportation needs. | Recovery from an event would be facilitated if a common event would not render both primary and backup control centers unusable. |
| 14. | **Agreements with Others** | Consider if other entities might be able to share control centers and telemetry. | Contracts should be in place for security, fuel delivery, sewage, and food supplies. Following an event prioritize contacting these suppliers and arrange deliveries. | Contract revisions will be necessary during the period of reconstruction. In some cases assistance from neighboring utilities may be necessary. |
| 15. | **Diversely routed telemetry** | Design and plan telecommunications paths such that both sites are not exposed to single points of failure. | Multiple telemetry routes should be available from all sources, especially the RC, as operation from the alternate could extend for a significant time. | Diversely routed telemetry would more readily enable operation for an extended duration after the event is over while the previously disabled or destroyed control centers are rebuilt. |

| MONITORING Resilience | | Preparedness: Prior to Event | Mitigation: During an Event | Recovery: After an Event |
|---|---|---|---|---|
| 16. | **Use of EOC or OTS as possible tertiary sites** | Anticipate possible use of emergency operations centers (EOC) or operator training simulators (OTS) as backup control centers and design them with the appropriate telemetry. | Dispatcher familiarity with the EOC and OTS from drills & exercises should facilitate and help recognize the need for various facilities for long term operation. | An EOC or OTS are more likely to have the necessary facilities to operate for an extended duration during the New Normal. |

# Appendix 3: Mitigations for Physical Attacks

This Appendix builds on the recommendations in the *Preventing and Responding to Physical Attacks* section of this report and highlights the different actions that may be taken, prior to, during, and after a Severe Event.




| | | Preparedness: Prior to Event | Mitigation: During an Event | Recovery: After an Event |
|---|---|---|---|---|
| | | **Robustness** The ability to absorb shocks and keep operating | **Resourcefulness** The ability to manage a disruption as it unfolds | **Rapid Recovery** The ability to get back to Normal as quickly as possible |
| **Communicate** | | | | |
| 1. | **ES-ISAC** | Develop and maintain procedures to report suspicious activity to ES-ISAC. | Report incidents to the ES-ISAC and monitor ES-ISAC alerts or advisories. | Continue updating ES-ISAC as appropriate. |
| 2. | **Local, State Authorities** | Develop, maintain, and exercise communication plans with local, state authorities. | Communicate with local, state authorities during response. | Continue communicating with local, state authorities during recovery. |

| | | Preparedness: Prior to Event | Mitigation: During an Event | Recovery: After an Event |
|---|---|---|---|---|
| 3. | **NERC** | Share prevention and preparedness phase lessons-learned. | Share mitigation phase lessons-learned. | Share recovery phase lessons-learned. |
| 4. | **Alternative Communications** | Develop, maintain alternative communication methods. | Execute alternative communication methods, as required. | Continue execution of alternative communication methods, as required. |
| 5. | **Crisis Communication Plan** | Develop, maintain, and exercise Crisis Communication Plan. | Activate Crisis Communication Plan. | Continue execution of Crisis Communication Plan. |
| 6. | **Public Reporting** | Develop, maintain, and exercise communication with the media to share information with the public in order to increase observations in the field (the public reporting strange happenings/sightings). | Use communication with the media to share information with the public in order to increase observations in the field (the public reporting unusual events). | Continue using communication with the media to share information with the public in order to increase observations in the field (the public reporting unusual events). |
| 7. | **Reliability Coordinator (RC)** | Utilities develop, maintain, and exercise communication plans with relevant RC. | Execute communication plans with relevant RC. Rapidly share lessons-learned with other entities. | Continue execution of communication plans with relevant RC, as required. |
| **Monitoring & Situational Awareness** | | | | |
| 8. | **Vulnerability Assessments** | Perform risk/vulnerability assessments and review at least annually. | Implement lessons-learned from other entities into security or operations plans. | Review vulnerability assessments for ability to estimate the actual threat, vulnerabilities, and impacts experienced. |

| | | Preparedness: Prior to Event | Mitigation: During an Event | Recovery: After an Event |
|---|---|---|---|---|
| 9. | **Controls** | Install, maintain, test, and monitor controls. For example:<br>• fences, gates, walls, berms<br>• access control systems/methods<br>• make assets less visible<br>• security guards and patrols<br>• smoke/heat detectors, motion sensors, cameras, etc. | Increase and adapt monitoring of implemented controls.<br><br>Consider random changes to security plans to reduce predictable actions. | Continue increased monitoring of implemented controls. |
| 10. | **Law Enforcement/ Military** | Develop and maintain coordination. | Increase coordination and adapt to current situation. | Continue increased coordination. |
| 11. | **SCADA Monitoring** | Review expansion of use of SCADA to monitor and report inappropriate activity. | Use SCADA to monitor and report inappropriate activity.<br><br>Work with IT to monitor SCADA for possible disruption. | Continue use of SCADA to monitor and report inappropriate activity. |
| 12. | **Situational Awareness by the Public** | Develop and implement programs to support situational awareness of facilities by the public. | Remind public of situational awareness and where to submit reports, provide for disruptions in routine communications. | Continue reminding public of situational awareness and where to submit reports.<br><br>Share intelligence and lessons-learned with communities. |
| 13. | **Monitoring Plans** | Train, exercise, maintain plans and teams to perform monitoring. | Activate appropriate monitoring plans and teams. | Continue execution of appropriate monitoring plans and teams. |
| 14. | **Intelligence** | Implement thorough intelligence gathering and reporting. (e.g., through ES-ISAC, RCs) | Increase intelligence gathering and reporting. | Continue increased intelligence gathering and reporting. |

| | | Preparedness: Prior to Event | Mitigation: During an Event | Recovery: After an Event |
|---|---|---|---|---|
| 15. | **Security Threat Levels** | Develop, maintain, and exercise a system of Security Threat Levels which is compatible with the National Terrorism Advisory System. Have procedures to be prepared to move to a different level based on perceived threats; and report the current level to authorities as appropriate. | When credible, specific, and impending terrorist threats to electric infrastructure becomes evident, change the Security Threat Level to IMMINENT and activate appropriate response and crisis management plans. When a credible terrorist threat becomes evident, change the Security Threat Level to ELEVATED, and monitor threats as appropriate. Report the current level to authorities as appropriate. | Continue monitoring threats and the current situation. Change the Security Threat Level, as appropriate. Report the current level to authorities as appropriate. |
| **Command & Control, Operate** | | | | |
| 16. | **Incident Response Plans** | Develop, maintain, and exercise Incident Response Plans. | Activate appropriate Incident Response Plans to protect facilities and personnel. | Continue execution of appropriate Incident Response Plans to protect facilities and personnel. |
| 17. | **Crisis Management Plan** | Develop, maintain, and exercise crisis management plans and crisis communication plans. | Activate crisis management plans and crisis communication plans. | Continue execution of crisis management plans and crisis communication plans. |

| | | Preparedness: Prior to Event | Mitigation: During an Event | Recovery: After an Event |
|---|---|---|---|---|
| 18. | **Crisis, Operations, Incident Teams** | Train, maintain, and exercise crisis management, crisis communication, emergency operations, and incident response teams.<br>Align and train teams in the National Incident Management System (NIMS) and the Incident Command System (ICS). | Activate appropriate crisis management, crisis communication, emergency operations, and incident response teams. | Continue activation of appropriate crisis management, crisis communication, emergency operations, and incident response teams. |
| 19. | **Protect Critical Infrastructure** | Develop, maintain, and exercise response plans with law enforcement to have them protect critical infrastructure when initiated by the operator owner. | Activate appropriate response plans to have law enforcement protect critical infrastructure.<br><br>Inform law enforcement as priorities regarding critical assets change. | Continue execution of response plans to have law enforcement protect critical infrastructure. |
| 20. | **Protect Field Personnel** | Develop, maintain, and exercise plans for the protection of field personnel after an attack. Protection strategies could include:<br>• Protection provided by local and state law enforcement and the National Guard<br>• Protection provided by a contractor with armed personnel<br>• Protection provided by field personnel themselves (armed?) | Activate appropriate plans for protection of field personnel after an attack. | Continue to implement and update plans for protection of field personnel during recovery and restoration. |

| | | Preparedness: Prior to Event | Mitigation: During an Event | Recovery: After an Event |
|---|---|---|---|---|
| 21. | **Mobile Control Center** | Develop, maintain, and exercise a mobile control center for use by security and crisis/incident management teams. Could be used as a security control center, emergency operations center, and/or incident command post. | Deploy and protect mobile control center where needed. | Continue deployment and protection of mobile control center where needed. |

# Appendix 4: Resilience Discussion Worksheet

## Introduction

The SIRTF report provides a framework to help entity management and subject matter experts review their plans and preparations and consider a Severe Event that is much greater in terms of impact and duration than current plans envision.

This Appendix provides a worksheet that could be used by business continuity and emergency preparedness personnel, system operators, and management to prompt creative thinking about the possible challenges they might face through a Severe Event. The worksheet builds upon the ideas and recommendations found within the SIRTF report and poses questions that may prompt new resilience ideas, mitigation responses, and other courses of action. The worksheet is not intended to require that a new and detailed response plan be developed for a Severe Event; instead, personnel are encouraged to challenge themselves to consider substantially worse scenarios to help ensure they and their organization will be in a better position to respond.

As such, the SIRTF recommends that entities use this worksheet to facilitate discussions involving personnel at all levels, including executive leadership, to enhance the entity's overall crisis preparedness and response capability. This worksheet is not exhaustive, and entities are encouraged to build further on the concepts and ideas offered.

## Decision Making

1. If many members of the organization's senior leadership team were unavailable because of travel restrictions, communications failures, or other post event challenges how would decision making authority be established?

| Possible Challenges Requiring Decisions | If this decision should fall to a few people – who? | If this decision should be made up of a team, who should comprise this team? |
|---|---|---|
| **Priority Load Designation** | | |
| **Changes to Operating Limits** | | |
| **Procurement Decisions** | | |
| **External Communications (Messaging)** | | |
| **Reassignment of Personnel** | | |
| | | |

2. What might be the triggers for re-evaluating certain decisions or the assumptions or both underlying these types of decisions?

| Decisions which may require periodic reevaluation: | What are the Triggers for reevaluation?<br><br>(i.e., Time Based, Changes in Operating State, External Requirements) |
|---|---|
| **Priority Load Designation** | |
| **Changes to Operating Limits** | |
| **Procurement Decisions** | |
| **External Communications (Messaging)** | |
| **Reassignment of Personnel** | |

## Business Continuity and Restoration Plans

3. How would your current **Business Continuity and Restoration plans** be disrupted if your organization had little to no communications? Which of these disruptions most troubles the following personnel?

| | What is most troublesome? | What makes this concern so critical? | What are possible mitigations? |
|---|---|---|---|
| **System Operator** | | | |
| **Field Personnel** | | | |
| **Procurement Team** | | | |
| **Executive Leadership** | | | |
| | | | |

4. Another way of examining the critical communications interdependence is to list each of your communication capabilities and prioritize the importance of these capabilities to your business continuity or restoration plans or both. Walk through how your organization would adapt its plans if you were to lose these capabilities, from the most critical to the least.

| Communications Capability | Possible Mitigations |
|---|---|
| **Phone Lines** | |
| **EMS/GMS Signals** | |
| **Cell Phones** | |
| **Satellite Phones** | |
| **Internet** | |
| **Radio** | |
| **Hand-Carried Messages** | |
| Other | |

5. What resource limitations create time constraints for portions of your business continuity or restoration plans or both?

| Possible Examples of Time Restraints | Possible Mitigations |
|---|---|
| **Nuclear Power BPS-supplied Power (six hours)** | |
| **Nuclear Power Back-up Diesels (7 days)** | |
| **Control Room Back-Up power (3 days?)** | |
| **Data Aggregation Points** | |
| **Communications Repeating Stations** | |
| **Sub-station Breakers** | |
| **Other** | |

6. For energy-related limitations how could the investment of renewable generation (e.g., wind, solar) extend these time restrictions? What would be other financial justifications beyond greater system resilience for making such an investment?

## Operations

1. If only limited data points are available, how would studies be performed?
2. If the Balancing Authority and Transmission Operator no longer have visibility of their systems:
   a. Who would become the new system operator and how would this be established?
   b. How would the extent (boundaries) of any resulting islands be determined?
   c. How would you implement the system restoration plan?
   d. What independent actions would equipment operators take? How are these actions known, coordinated and trained?
   e. What system information (e.g., generator characteristics, load characteristics, limits) would be shared with the new system operator and how?
   f. What communication methods and protocols would be used to keep the Reliability Coordinators, Balancing Authorities and Transmission Operators updated on local system conditions and restoration progress?
   g. How will variable generation resources be managed during restoration and New Normal timeframes?

3. How would the following system parameters be managed immediately following the Severe Event and during the New Normal?

| Challenge | Possible Mitigations to determine MW, MVAR output and resulting frequency |
|---|---|
| **BA has No Communications with Market/Generation Operation (MOC/GOP) Centers** | |
| **BA has no communications with units but can communicate with MOC/GOP** | |
| | |
| | |

4. How would your organization consider its operating assumptions and limits? At what point is it appropriate to revisit, and possibly revise, protection settings on relay settings, UFLS and other protection schemes?
5. What rules of thumb should be provided to system operators for operating in the New Normal?
6. Assuming a total blackout with no outside assistance and no expectation to interconnect in the near term:
   a. What units are most essential to the restoration plans?
   b. How many days of fuel do generating stations typically have on hand? Are there contracts regarding fuel on hand for important sources of generation, especially those needed for blackstart? How does such a number of MWh define the load to be served, the rotating blackout schedule, and the amount of reserves carried?
   c. What concerns do you have about units that do not have station power and lighting needs served?
      - How many days before a unit might be damaged? What ways could resources be committed to protect such units?
      - What if the Severe Event prevents BPS supply to the nuclear units and is expected to last beyond the technical specification requirement to have seven days fuel on hand for the back-up diesels?

7. How will new load patterns be established? What are the critical and priority loads that need to be served? Do these change based on different event outcomes and timeframes? If so why?
8. What loads are not essential and do not need to supplied over the long term?
9. Will Operating reserve requirements be met by load shedding or by reserving generation capacity? Why? What are factors that may change this assessment?
10. In the event that there are no market mechanisms and tools available to dispatch generation, what alternative mechanisms can be used?

## Logistics and Interdependencies

11. What infrastructures are your critical facilities most dependent on?

| Critical Infrastructure | What is most troublesome? | What makes this concern so critical? | What are possible mitigations? |
|---|---|---|---|
| **Communications** | | | |
| **Energy** | | | |
| **Water & Dams** | | | |
| **Information Technology** | | | |
| Other | | | |

12. Of these infrastructures, which have critical facilities (those facilities essential to bulk power system operation) within your zone (and maybe in your neighbors' zones)?

| Facility & Contact Info | Critical Infrastructure | Location | Impacts & Time to Impact |
|---|---|---|---|
| **1.** | | | |
| **2.** | | | |
| **3.** | | | |
| **4.** | | | |
| 5. | | | |

13. What are the energy needs of these critical facilities?
14. How would a total blackout restoration plan address these facilities' energy needs?

15. What hard-stop time limits can these facilities endure without power before there is damage or second or third order impacts to other infrastructures and/or the bilk power system. How are these time limits factored into your own plans?

## People

1. For each of the major functions within your organization related to the reliability of the bulk power system, which are most critical?

| Critical Organizational Function | Point or Primary Person/Department | Secondary Person/Department | Tertiary Person/Department |
|---|---|---|---|
| **1. Operations** | | | |
| **2. Communications - Hardware** | | | |
| **3. Communications - Messaging** | | | |
| **4. Emergency Liaison** | | | |
| 5. | | | |

2. Based on the assessment of critical functions, how would personnel within these functions be directed?
   a. When should they report to work following a Severe Event?
   b. Do they all report at once, and then a schedule is created, or is there a standing set of instructions?
   c. How would transportation challenges be addressed under the following scenarios?
      - State/provincial or local travel restrictions
      - Gas pumps are not working, and personnel's private vehicles have insufficient fuel to get to work.
      - Consumers wanting to know when their power will be restored routinely interrupt and delay utility personnel engaged in restoration efforts.
   d. How would you address personnel concerns about their families?
      - In the first couple of days following a Severe Event
      - 10 days after a Severe Event
      - One – six months after a Severe Event
   e. How would you house, feed, and care for these personnel?

## Financing

1. How can each corporate function best prepare and respond to a Severe Event?

| Critical Organizational Function | What can you do to prepare for a Severe Event? What resources are available? | How will you function during the new normal? | How will your area facilitate the return to normal BPS reliability levels? |
|---|---|---|---|
| **1. Insurance** | | | |
| **2. Procurement** | | | |
| **3. Risk Management** | | | |
| **4. Finance** | | | |
| **5. Collections** | | | |
| **6. Labor Relations** | | | |
| **7.** | | | |

# Appendix 5: Severe Event Response Checklist

This Appendix provides a checklist of questions that may be used by entities through a Severe Event to periodically assess the situation and decide new courses of action as system conditions and circumstances evolve through the New Normal period.

**Date:** _____ **Time**: _____

## System Topology

What are the current island boundaries?

1. Are these being operated in an unstudied state?
2. Depending on the electrical configuration of the island(s), which operating security limits may no longer be appropriate?
    a. Why are these limits inappropriate?
    b. Conversely, why are other limits still appropriate?
    c. Of those limits which require additional study
        - Which limits should be prioritized?
        - What decision criteria are used to determine this priority?
3. Is the system configuration suitable for restoration?
    a. How do we know this?
    b. Have breakers been opened along the restoration path?
    c. Who is working on this confirmation?
4. Will the current protection schemes/SPS/UFLS/UFLS settings impede or assist with the current system's operations?
    a. What protection changes are practical at this time?
    b. How are the decision criteria for "practical" defined?
        - If changes are merited, with the limits in the current workforce, communications, and other resources how will the priority of these changes be determined?
        - How will these changes be coordinated as connections are made with other islands?

## Generation

1. What generation is damaged and what is fully capable and available?
    a. What is keeping the unavailable units in this state?
    b. Are the fixes that are required under the organization's control, or what assistance is needed?
2. Which units in the island are blackstart capable and available?
3. What is the fuel availability for each unit within the island?
4. Do any of these units have regulatory restrictions that are limiting their capacity?
    a. How can these restrictions be addressed?
    b. Who is the decision maker?

## Transmission Lines and Substations

1. What is the status of key substations?
    a. How critical is the key substation in the current system configuration?
    b. What is the status of key elements within the substation (transformers, busses, breakers, reactive elements)?
    c. Can the substation be reconfigured to use good equipment and bypass bad equipment
2. What equipment can be cannibalized to restore key substations?
    a. Can redundancy (per standard requirements) be minimized/eliminated to provide a larger restoration footprint such as moving redundant transformers to key substations or creating radial configurations on breaker and a half configurations to free up additional breakers for key substations)?
    b. In what timeframe can the cannibalization occur?
    c. What is the availability of specialized equipment (railcars, cranes etc.)?
3. What is the status of key transmission lines?
    a. Breaker status, operable, etc.
    b. If line is out of service, has a line inspection been completed and any potential faults resolved?
    c. Can lines be re-configured to by-pass damaged substations?

## Key Equipment

1. What is the status of key equipment?
    a. Damaged equipment (repairable or not)
    b. Replacement equipment
    c. Cannibalization

## Load

1. What are the critical loads needed to operate the bulk power system?
   a. Within an island?
   b. Beyond the island, that may drive restoration priorities
2. What are the priority loads needed to support public health and safety?
   a. Within an island?
   b. Beyond the island that may drive restoration priorities
   c. What are the decision criteria for ranking these priority loads?
   d. Who are the decision makers for the current priorities?
      - Are we able to communicate with these decision makers?
      - If there are no communications with this decision maker, who will make the decision?
      - How do we share and coordinate these priority load decisions?

## Communications

1. Who am I able to talk to in my role as a _____?
2. Who must I talk with in my role as a _____?
3. What are the means to mitigate these communication gaps?

## People

1. Are key personnel available to perform their role?
   a. How can they best be used?
   b. What key personnel gaps need to be filled, and from where?
2. What extraordinary safety concerns need to be addressed?
   a. How will personnel be kept informed of any security-related risks?
   b. How will field changes be documented so field operating and system operators are kept informed?

## Monitoring

1. What is the organization's situational awareness of the current island?
2. Why can this situational awareness be trusted?
3. Are there other entities that might help provide additional situational awareness?
4. Based upon current topology – what are the most essential data points
    a. Which of these essential data points is missing?
    b. What are the possible mitigations to acquire these essential data points?
5. What other mechanisms can be used to gain some visibility of the system, no matter how limited or rudimentary?

## Financing

1. What funding is available to support continued operations in the short term? How will operations be funded in the long term?
2. What funding can be shifted away from low and medium priority projects given the new normal configuration?
3. How will employees be paid if electronic transactions are not available?
4. How will customers pay bills if electronic transactions are not available?
5. How will your revenue stream be impacted? Will customers be willing to pay given the expected decrease in reliability? Will customers be able to pay given the expected economic impacts?
6. How widespread is the event? How much state or provincial aid will be available? Is federal assistance available?

# Appendix 6: NERC SIRTF Roster

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# GC Profile: Charles A. Berardesco of Constellation Energy

POSTED: 2:20 PM THU, MAY 27, 2010
BY **WAYNE COUNTRYMAN**
DAILY RECORD ASSISTANT EDITOR

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Charles A. Berardesco

Charles A. Berardesco, senior vice president, general counsel, corporate secretary and chief compliance officer of Baltimore-based Constellation Energy was recognized recently by Corporate Board Member magazine as a "General Counsel to Watch" during its third annual Legal Recognition Dinner for "America's Best Corporate Law Firms" and top general counsels.

He was chosen for his role in the closing of Constellation Energy's nuclear joint venture with EDF Group and leadership of Constellation Energy's corporate governance practices. Berardesco also serves as the chairman of the corporation's Diversity Council.

Berardesco joined Constellation Energy in 2003 as associate general counsel. In the nearly 20 years before then he had served as vice president, general counsel and corporate secretary of Fusara, a consortium of AIG, Kemper and Prudential; as senior vice president, general counsel and corporate secretary of HCIA, a publicly held health care information company; counsel with Piper Rudnick (now DLA Piper); and as a partner with Whiteford, Taylor & Preston, where he chaired the corporate department.

His leadership extends to the community, including having served as chairman of the board of the Woodbourne Center, president of the Presbyterian Home of Maryland, and chair of the Church Council of Foundry United Methodist Church. Berardesco also is a member of the board of directors of the Baltimore Choral Arts Society and of the Business Council of the Human Rights Campaign.

-

## Charles A. Berardesco

**Education:** I graduated from Duke University in 1980 with a bachelor of arts in political science, and from George Washington University in 1983 with my law degree.

**Daily commute:** About 35 miles – I live in the Logan Circle area of D.C. My partner works at the Kennedy Center and is a busy freelance violinist in D.C., so living there helps him to be able to do what he loves, and the commute to Baltimore is just a lot easier than the commute into D.C.

**Most recent vacation:** My partner and I went to our home in Provincetown on Cape Cod – our absolutely favorite place in the world. I relax there like nowhere else.

**Hobbies:** I love music and theater, and attend as many things as I can. I sing in my church's choir as a second tenor – there is almost nothing like the power of presenting profound choral music in a sacred space. And just to shake things up, I also mix some pretty mean cocktails.

**Favorite books:** I read a lot of history and historical fiction. It is hard to pick favorite books, but in terms of history, I would say "Nicholas and Alexandra" by Robert Massie,

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which I first read in 8th grade and which opened my eyes to how history can be written in a way that is challenging and readable. It launched a life-long interest in Russian history for me and led to my visiting Russia when I was 15 years old, back in 1974 – an amazing experience. In terms of fiction, I love Colleen McCullough's novels set in Ancient Rome, and the novels set in the Napoleonic era British navy by Patrick O'Brian.

**Most recently read:** I am currently reading a history of World War I by the military historian John Keegan, and a novel about the history of New York City by Edward Rutherford. My most recently completed book was a biography of the Julio-Claudian emperors – from Augustus to Nero. But, a book I read recently that really opened my eyes was "The Ornament of the World", a history of Andalusian Spain, which I found absolutely fascinating, as I knew relatively little about that period of history. It describes a period of history when Christians, Jews and Muslims were able to live together in a society of relative tolerance that produced a rich fabric of literature, art and architecture.

**Favorite food:** I come from an Italian family – my dad's parents were both born in Italy and moved to the U.S. in the 1930s. We had dinner with them pretty much every Sunday when I was growing up, so I love basic Italian food – lasagna, macaroni, really good meatballs and sausages. My dad is also an incredible cook, and when I visit my parents in New Jersey, I always hope that a macaroni and meatballs/sausage dinner is on the menu.

**Most memorable professional experience:** Certainly, our recent transaction with Electricite de France has to top the list – terminating our transaction with Berkshire Hathaway's energy company as part of a non-conforming topping bid by EDF, and negotiating in less than a week a joint venture transaction with EDF to operate U.S. nuclear power plants, a first of its kind in the U.S. The entire transaction, from agreeing to negotiate with EDF to the very public nature of the approval process in Maryland, required a constant focus on detail, strategy and potential alternatives.

From the earlier part of my career, I will never forget my first public offering, which was for the parent company of the Holiday Spa chain. On the night when we priced the debentures, the board decided to increase the size of the offering, which required an additional filing fee – which could only be paid via a certified check, cashier's check or cash (this was before the days of electric filings and SEC lockboxes) – and, we had committed to having the registration statement effective before the opening of the market. So, we ended up scouring Baltimore for cash in the middle of the night, including getting money from the few ATM machines around, borrowing it from relatives of the team, and even pitching a few dollars in ourselves. It was quite a surprise to the SEC filing desk when I showed up at 8:30 in the morning with a wad of cash to pay the additional filing fee.

**What I like best about my current position:** I work in an incredibly dynamic and interesting industry that everyone cares about – I mean, who doesn't care about the price of their electricity? My management colleagues are incredibly smart and fun, and my legal team is experienced, talented, hard working and truly appreciated by the business. I feel very fortunate to be able to practice law in this kind of environment.

**Most rewarding extracurricular activity:** I would say my work at my church – I sing in the choir, I help raise funds for our annual Concert for Life, which is a benefit concert for people with HIV/AIDS, and I have served in various leadership roles, including chair of the governing board. A close second is my work with the Human Rights Campaign, where I serve on the Business Council.

**Local heroes/heroines**: My number one local hero without a doubt is Woody Preston, the former managing partner of Whiteford, Taylor & Preston, where I had the honor of practicing law for 8 years before my first in-house job. Woody taught me the importance of integrity and a focus on excellence, and also taught me you can be a great lawyer and a great person. He was a legend in the legal community, and yet knew the name of every single person at the firm – and he always had time to talk with people and celebrate their accomplishments.

I would also add Jan Houbolt, who has led the Greater Baltimore Committee Leadership Program since its inception. Jan brings a passion to the program, and has helped countless business leaders better understand the profound challenges and opportunities of the Baltimore community.

Finally, I need to mention Dr. Stanley Weinstein, who is the CEO of the Woodbourne Center. I had the honor of serving on the Woodbourne board for a number of years, including during some incredibly challenging times for the organization. Stan is first and foremost focused on the care of the children that Woodbourne serves, and then on the

wonderful staff of that organization. He is a man of vision and drive, and every day he and his colleagues are making a real difference in the lives of countless children in our community.

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MIDWEST RELIABILITY ORGANIZATION

380 St. Peter Street, Suite 800, Saint Paul, MN 55102 MidwestReliability.org P. 651.855.1760 F.651.855.1712

Date: May 24, 2012

To: Midwest Reliability Organization (MRO) Stakeholders

From: Will Smith, Manager of Standards and Program Performance

Cc: MRO Standards Committee

Subject: Ballot Results for Version 5 of the MRO Standards Process Manual

Dear MRO Stakeholders,

MRO Stakeholders were notified on March 30, 2012 of the 10-day ballot period for Version 5 of the Standards Process Manual (SPM). The ballot period was open from April 13, 2012 to April 23, 2012. Responses were received from four of the seven segments; thus achieving a quorum. All responses from the responding segments were affirmative confirming approval of the proposed revisions. Pursuant to section VII (Maintenance of MRO Regional Reliability Standards Process) of the SPM, these proposed revisions are hereby posted on the RSVP website as of May 24, 2012. These changes will be submitted to the MRO Board of Directors for approval at the Board's regularly scheduled meeting on June 28, 2012.

Please contact me with any questions at 651-855-1718 or ws.smith@midwestreliability.org.

Sincerely,

Will Smith
Manager of Standards and Program Performance

**From:** Kimberly Mielcarek
**To:** Kimberly Mielcarek
**Subject:** NERC Release - Summer Reserve Margins Predicted to be Adequate in Most Regions; ERCOT Below Reserve Capacity Targets
**Date:** Wednesday, May 30, 2012 10:24:57 AM

# Media Release

## Summer Reserve Margins Predicted to be Adequate in Most Regions; ERCOT Below Reserve Capacity Targets

**Click for announcement, 2012 Summer Reliability Assessment**

**ATLANTA** – Most of North America has sufficient resources available to meet summer peak demands, the North American Electric Reliability Corporation's (NERC) *2012 Summer Reliability Assessment* finds. However, planning reserve margins in the Electric Reliability Council of Texas (ERCOT) assessment area are projected to be below the NERC Reference Margin Level, the threshold by which resource adequacy is measured. In California, reserves are projected to be tight, but manageable, through the summer months.

For more information or assistance, please contact Kimberly Mielcarek.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Summer Reliability Assessment

2012

RELIABILITY | ACCOUNTABILITY






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# Preface and NERC Mission

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system of North America.[1,2] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, México.

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces reliability standards; assesses reliability annually via a 10-year assessment, and winter and summer seasonal assessments; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[3]




| | |
|---|---|
| **FRCC** | Florida Reliability Coordinating Council |
| **MRO** | Midwest Reliability Organization |
| **NPCC** | Northeast Power Coordinating Council |
| **RFC** | ReliabilityFirst Corporation |
| **SERC** | SERC Reliability Corporation |
| **SPP RE** | Southwest Power Pool Regional Entity |
| **TRE** | Texas Reliability Entity |
| **WECC** | Western Electric Coordinating Council |

NERC assesses the reliability and adequacy of the North American bulk power system, which is divided into several assessment areas within and across the eight Regional Entity boundaries, as shown in the map and corresponding table above.[4] The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, México.

[1] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005: http://www.gpo.gov/fdsys/pkg/BILLS-109hr6enr/pdf/BILLS-109hr6enr.pdf

[2] The NERC Rules of Procedure, Section 800, further detail the Objectives, Scope, Data and Information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

[3] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in British Columbia, Ontario, New Brunswick, and Nova Scotia. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory and enforceable in that jurisdiction.

[4] Assessment area boundaries are included in Appendix I of this assessment.

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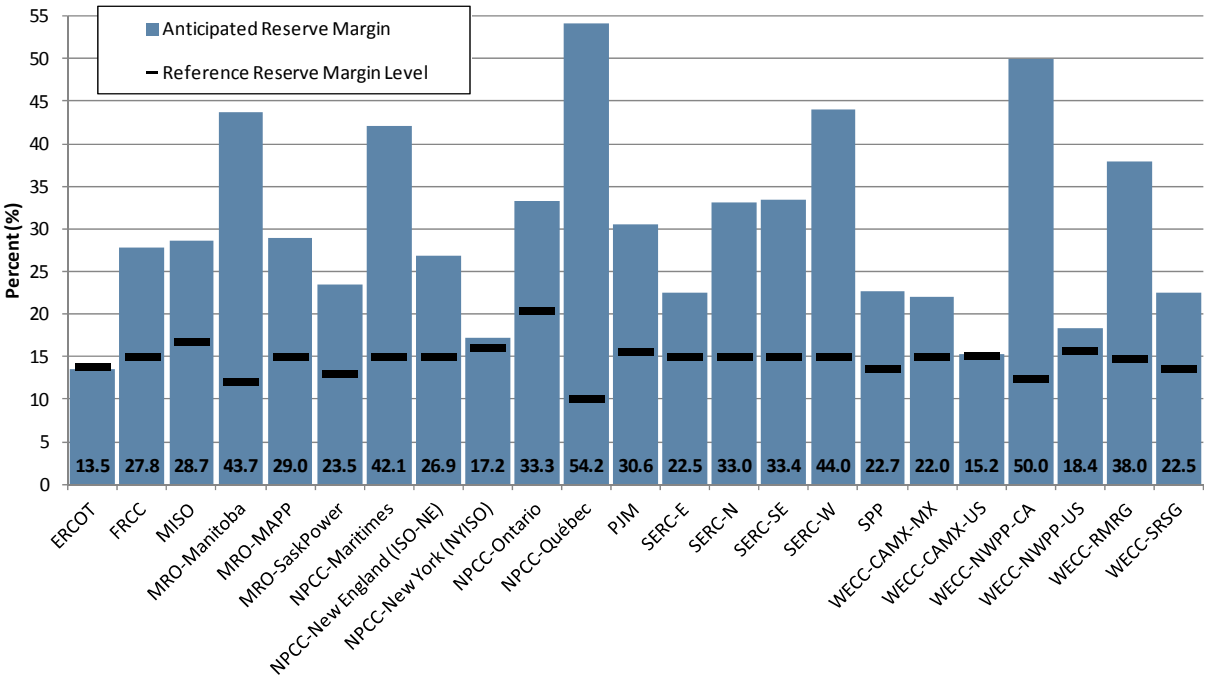
# Executive Summary

## 2012 Summer Key Highlights

**Extreme weather could lead to stressed conditions in Southern California and Texas; planned interruptions of firm load in Texas and Southern California may be necessary**

For the 2012 summer operating period (June 1, 2012 through September 30, 2012), a majority of the assessment areas are projecting sufficient resources to meet summer peak demands. However, Planning Reserve Margins for ERCOT are below the Reference Margin Level. Figure 1 shows the reserve margins for the peak demand month (which varies for each assessment area) for the 2012 summer operating period. Insufficient reserves during peak hours could lead to an increased risk of entering emergency operating conditions, including the possibility of curtailment of interruptible loads and even rotating outages of firm loads.

**Figure 1: Anticipated Reserve Margins for the 2012 Summer**



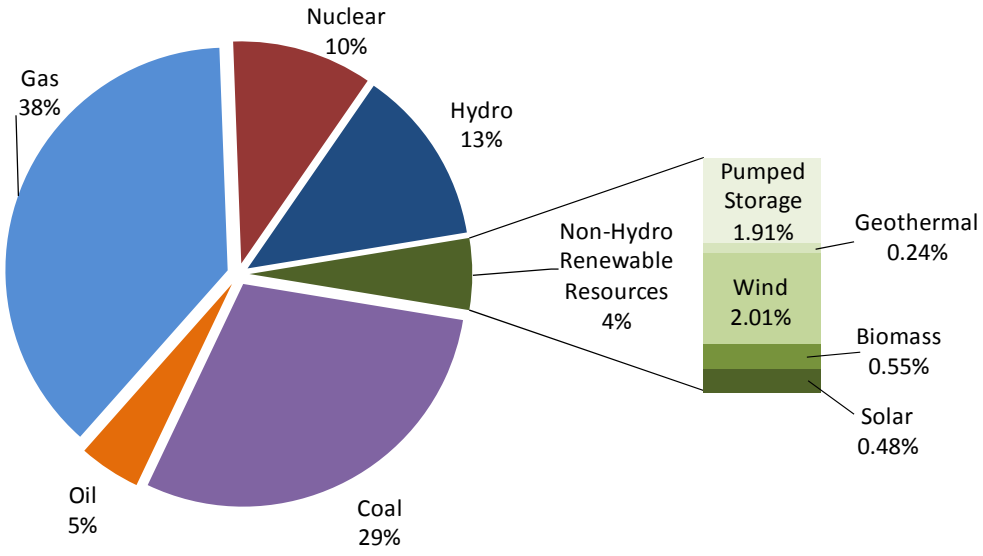

Since the summer of 2011, NERC-wide capacity resources have grown by approximately 12,310 MW. Capacity growth is projected in a number of assessment areas, including significant growth in SERC-W (4,410 MW growth, 12.7 percent increase), SERC-SE (3,320 MW growth, 5.4 percent increase), and NPCC-New England (2,227 MW growth, 7.5 percent increase). While PJM shows the largest absolute growth, the increase is primarily due to the integration of Duke Energy Ohio/Kentucky (DEOK). Figure 2 shows the change in summer capacity from the summer of 2011 to the summer of 2012.

**Figure 2: 2011 and 2012 Net Change in Summer On-Peak Capacity[5,6]**

| | 2011 | 2012 | % Change | Capacity Decrease / Capacity Increase |
|---|---|---|---|---|
| PJM | 180,406 | 185,424 | 2.78% | 5,018 |
| SERC-W | 34,713 | 39,123 | 12.71% | 4,410 |
| SERC-SE | 61,072 | 64,392 | 5.44% | 3,320 |
| NPCC-New England (ISO-NE) | 29,590 | 31,781 | 7.40% | 2,191 |
| SPP | 61,600 | 63,549 | 3.17% | 1,950 |
| WECC-Total | 173,687 | 175,228 | 0.89% | 1,541 |
| SERC-N | 57,632 | 59,106 | 2.56% | 1,474 |
| NPCC-Québec | 33,222 | 33,907 | 2.06% | 685 |
| MRO-MAPP | 7,078 | 7,321 | 3.43% | 243 |
| MRO-SaskPower | 29,821 | 29,875 | 0.18% | 14 |
| MRO-Manitoba | 3,632 | 3,647 | 0.39% | 7 |
| ERCOT | 5,364 | 5,371 | 0.13% | -10 |
| MISO | 73,080 | 73,070 | -0.01% | -164 |
| SERC-E | 107,391 | 107,227 | -0.15% | -675 |
| NPCC-Ontario | 29,821 | 29,125 | -2.33% | -696 |
| NPCC-Maritimes | 5,853 | 4,599 | -21.42% | -1,254 |
| NPCC-New York (NYISO) | 36,700 | 34,908 | -4.88% | -1,792 |
| FRCC | 55,775 | 52,351 | -6.14% | -3,424 |

NERC-wide on-peak capacity projections for the 2012 summer do not change significantly, compared to the summer of 2011 projections. Gas-fired generation continues to be the dominant on-peak fuel source during periods of peak, followed by nuclear and coal generation to cover base load. Figure 3 includes the projected NERC-wide on-peak capacity mix for the 2012 summer.

**Figure 3: 2012 Summer On-Peak Capacity Mix[7]**




[5] Capacity values include Existing-Certain and Future-Planned capacity for the summer peak month.

[6] Duke Energy Ohio/Kentucky (DEOK) exited from MISO and integrated into the PJM RTO on January 1, 2012. This accounts for a 5 GW shift in capacity. WECC subregional boundary changes in 2012 have also distorted direct subregional comparisons.

[7] Data presented in this chart is based on the data collected for the *2011 Long-Term Reliability Assessment* capacity forecasts (Schedule 9A and 9B).

For the 2012 summer, NERC is forecasting a reduction in Total Internal Demand of approximately 3,700 MW (or 0.4 percent). While some areas are forecasting modest growth in demand, most areas are projecting either a reduction or flat growth in peak demand when compared to the 2011 summer. ERCOT and New York (the NPCC-NYISO assessment area) show the largest percentage growth, with each area forecasting approximately 1.7 percent of increased peak demand. Conversely, the SERC-N, and MRO-MAPP (primarily North Dakota, South Dakota, and Minnesota) show the largest relative decrease in peak demand compared to last year – approximately 5.7 percent. SERC-N also shows the largest absolute reduction since last year. Figure 4 includes the 2011 forecasted and actual Total Internal Demand versus the 2012 summer forecast.

**Figure 4: 2011 and 2012 Summer Total Internal Demand[8]**

| | 2011 Forecast | 2011 Actual | 2012 Forecast | Forecast % Change | Demand Decrease / Demand Increase |
|---|---|---|---|---|---|
| ERCOT | 64,964 | 68,416 | 66,076 | 1.71% | 1,112 |
| NPCC-New York (NYISO) | 32,712 | 33,865 | 33,295 | 1.78% | 583 |
| SPP | 53,512 | 55,352 | 54,051 | 1.01% | 539 |
| SERC-W | 25,101 | 25,585 | 25,403 | 1.20% | 302 |
| WECC-Total | 149,148 | 147,299 | 149,173 | 0.02% | 25 |
| SERC-E | 43,249 | 43,253 | 43,255 | 0.01% | 6 |
| MRO-SaskPower | 3,045 | 2,988 | 3,044 | -0.05% | -1 |
| MRO-Manitoba | 3,166 | 3,378 | 3,143 | -0.73% | -23 |
| NPCC-Ontario | 23,561 | 25,450 | 23,409 | -0.65% | -152 |
| NPCC-Maritimes | 3,553 | 3,329 | 3,392 | -4.53% | -161 |
| MRO-MAPP | 5,087 | 4,732 | 4,799 | -5.67% | -288 |
| NPCC-Québec | 21,283 | 21,354 | 20,988 | -1.39% | -295 |
| SERC-SE | 49,314 | 50,309 | 48,895 | -0.85% | -419 |
| FRCC | 46,091 | 44,798 | 45,613 | -1.04% | -478 |
| NPCC-New England (ISO-NE) | 27,550 | 33,865 | 26,462 | -3.95% | -1,088 |
| PJM & MISO | 248,513 | 257,135 | 246,884 | -0.66% | -1,629 |
| SERC-N | 46,846 | 45,579 | 45,102 | -3.72% | -1,744 |

**The unanticipated outage of the San Onofre Nuclear Generating Station (SONGS) reduces available summer capacity; transmission ties critical to reliability of Southern California**

In California (the WECC-CAMX-US assessment area), Planning Reserve Margins are above the NERC Reference Margin Level for the upcoming summer. The Anticipated Reserve Margin for WECC-CA-MX for the peak month of July is 15.2 percent, 0.1 percent above the area's target level (15.1 percent).The San Onofre Nuclear Generating Station (SONGS) Units 2 and 3 – a total of 2,150 MW – will remain out of service throughout the summer due to premature wear in the steam tubes of these units. The unavailability of this plant and a continuation of drought conditions accompanied with a stretch of higher-than-average temperatures or significant generation or transmission outages, could result in the deployment of load

[8] With Duke Energy Ohio/Kentucky (DEOK) exiting MISO and integrating into the PJM RTO on January 1, 2012, NERC has combined the demand projections from both assessment areas to provide comparable forecasts between 2011 to 2012. WECC subregional boundary changes in 2012 have also distorted direct subregional comparisons to 2011 projections.

shedding procedures in the San Diego and Los Angeles Basins to maintain the reliability of the bulk ower system.

Although ERCOT and the California Independent System Operator (CAISO) have worked diligently to mitigate reliability risks for this summer, maintaining sufficient operating reserves will likely remain a challenge, especially if extreme weather is experienced. Both areas have instituted procedures for bringing mothballed units back into service, accelerating the completion of needed transmission projects, and establishing customer agreements to provide more peak reduction capability. In California, with 14,000 MW of expected import transfers from neighboring areas, increased reliance on transmission ties to import the required power could further stress the system. At the time of this report's publication, system planners and operators continue preparation efforts as well as the development of operating procedures to manage extreme conditions that can further stress the bulk power system.

**Enhanced operations and planning approaches instituted in response to 2011 southwest outage**

The September 8, 2011 event stemmed primarily from weaknesses in two areas: operations planning and real-time situational awareness. These same weaknesses were identified in the August 2003 blackout that affected an estimated 50 million people in the northeastern United States and Canada. Without adequate operations studies and situational awareness, entities responsible for operating and overseeing the transmission system could not ensure reliable operations within System Operating Limits (SOLs) or prevent cascading outages in the event of a single contingency, such as the loss of a single transmission line.

To improve situational awareness in the WECC Region, recommendations were made to: (1) expand entities' external visibility in their models through, for example, improved data sharing and expanded use of Inter-Control Center Communications Protocol (ICCP) data links or similar technology; (2) improve the use of real-time tools to ensure the constant monitoring of potential contingencies; and (3) improve communications between entities to help maintain situational awareness.

**Variable generation continues to increase in most assessment areas**

Variable generation continues to increase in most assessment areas. Specifically, MISO and New England have reported significant increases in nameplate wind capacity for the 2012 summer operating period. A total of 4,576 MW of nameplate wind generation has been installed since last year, reflecting a modest increase of 1,880 MW of expected capacity on-peak. Solar and other renewables have not significantly increased since last summer, but are expected to in the longer term. Additional information on this issue will be provided in the NERC *2012 Long-Term Reliability Assessment*.

Operationally, an increase in wind resources continues to challenge operators with the inherent swings, or ramps, in power output. In certain areas, where large concentrations of wind resources have been added, system planners must accommodate added variability by increasing the amount of available regulating reserves, and potentially carrying additional operating reserves.

**Demand-side management key in maintaining reliability this summer**

Demand-side management programs, which include conservation, energy efficiency, and a variety of demand response programs, provide the electric power industry the ability to reduce peak demand and to potentially defer the need for some future generation capacity. With tight margins in some areas, successful deployment of demand response will be critical for maintaining reliability this summer. Depending on summer conditions, demand response may be used more often this summer in areas with tight margins, such as Texas and Southern California.

**Extreme weather events will challenge bulk power system operators**

Operational issues may challenge the industry during the upcoming summer, which would require increased flexibility to manage reliability impacts, such as weather (extended periods of high temperatures), long-term unavailability of generation, drought, and environmental restrictions (for cooling water). Many of these issues reflect the operating conditions expected in Texas. While drought conditions have improved since last year, persistent effects are expected through the summer. Tight reserve margins will impact the ERCOT system operator's flexibility to deal with unexpected or more extreme situations (*i.e.*, significant generator outages and/or higher than expected demand).

**Lower global LNG supply may impact LNG-dependent generation in New England; ISO to implement proactive measures**

NERC does not expect any significant fuel supply or delivery issues for the summer months. However, foreign supply-chain issues could reduce the amount of LNG shipped into New England this summer. ISO-NE is currently developing procedures to ensure plants operate during peak periods.

Fuel supply constraints in all other areas are less likely due to ample on-site coal inventories and sufficient natural gas supplies, including unprecedented storage spurred by an increase in shale production and a mild winter. While natural gas transportation issues remain a concern, given the increase in gas-fired generation and associated interdependency issues, these risks are generally more prominent during the winter seasons when gas pipeline and electric system can peak at the same time.

**Environmental Regulations not expected to impact reliability in the short-term**

Forthcoming environmental regulations continue to be evaluated in planning processes across the United States. Remaining uncertainties about unit retirements, Section 316(b), and retrofit and maintenance schedules are being assessed for long-term planning. However, for this summer, no impact is expected from any of the pending and/or final environmental rules. While some generator retirements have already been announced, all retirements have been accounted for and included in this assessment. Additionally, there is little uncertainty that generators would retire or derate between the time of this publication and the summer peak. Because of the longer-term reliability risks associated with the electric industry's response to comply with environmental regulations, NERC will continue to monitor industry progress and report on developing issues in the *2012 Long-Term Reliability Assessment*.

# Top Reliability Issues for Summer 2012

## To maintain reliability, planned interruptions to Firm load may be necessary in Texas

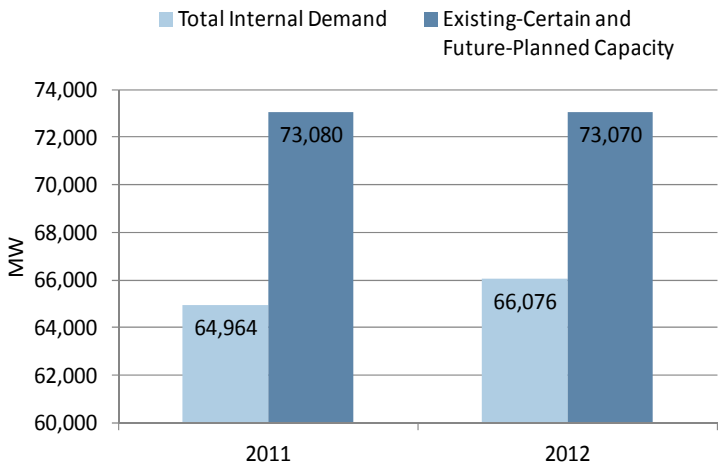
**1,100 MW**
increase in peak demand

**10 MW**
reduced capacity
since last summer

During the 2012 summer operating period, the ERCOT Independent System Operator (ISO)[9] is expecting the assessment area to be below the Reference Margin Level in August 2012. Specifically, an Anticipated Reserve Margin of 13.51 percent is below the ERCOT criteria of 13.75 percent. With the ERCOT ISO reserve margin below the NERC Reference Margin Level, ERCOT does not appear to have sufficient resources to maintain required resource adequacy levels. This may result in an increased probability of interruptions of firm load to maintain reliability.

The projected summer peak Total Internal Demand in ERCOT is 66,076 MW, which will occur in August. The 2012 summer forecast is 2,340 MW less than the all-time record-peak demand of 68,416 MW[10] in ERCOT, which occurred last year on August 3, 2011 during extreme weather conditions which were experienced throughout the southern United States. With 73,070 MW of projected capacity resources, reserve capacity needed to accommodate unplanned forced outages and load forecast deviations diminishes to less than 7,000 MW, as shown in Figure 5.

**Figure 5: 2011 and 2012 ERCOT Demand and Capacity Forecast**




If ERCOT incurs an above average number of generation outages or experiences record-breaking electricity demand due to the onset of extreme temperatures again this summer, ERCOT may need to initiate rotating outages to maintain the reliability of the interconnection.[11]

During the 2011 summer peak, approximately 4,000 MW of generation was unexpectedly forced out of service. Additionally, the actual peak demand experienced in August was approximately 3,500 MW above the projected Total Internal Demand. During the onset of extreme August temperatures, ERCOT implemented emergency procedures on six days, due to low operating reserve capacity. Demand conservation that was practiced by consumers and businesses, coupled with non-Firm load-shed, helped to alleviate the need for ERCOT

[9] The Electric Reliability Council of Texas (ERCOT) is the Independent System Operator for the ERCOT Interconnection and schedules power on an electric grid that connects 40,500 miles of transmission lines and more than 550 generation units. Texas Reliability Entity (TRE) is the Regional Entity responsible for assessing the reliability of the bulk power system within ERCOT.

[10] ERCOT 15 minute demand value; the 2012 forecast is 2,340 MW less than the all-time peak experienced during the 2011 summer.

[11] Interruption of Firm load and rotating outages are tools that system operator can deploy to maintain the stability of the bulk power system and avoid uncontrolled, cascading outages of large areas.

system operators to initiate rotating outages of Firm load. Should similar conditions occur this summer, little flexibility will be available to system operators and maintaining reliability could be a significant challenge.

In advance of the summer operating period, ERCOT and generation capacity owners in Texas have taken a number of actions to enhance resource adequacy to ensure the reliable operation of the ERCOT Interconnection.

Actions taken by ERCOT included approving the Nodal Protocol Revision Requests (NPRR) to enhance resource adequacy for the summer operating period. NPRR outlines the procedures and processes used by ERCOT and market participants for the orderly functioning of the ERCOT system and nodal market. The two NPRRs approved during the April 2012 ERCOT Board of Directors meeting to enhance reliable operations for the 2012 summer operating period, are as follows:

- NPRR450 – Revise Requirements for Contracts to Procure Additional Capacity to Alleviate Emergency Conditions (Effective: 5/1/2012). This action authorizes ERCOT to contract for generation and load resources to address emergency conditions and to notify the ERCOT Board of such actions at its next meeting.[12]
- NPRR 451 – Implementation of new Texas Public Utility Commission (PUC) Substantive Rule §25.507. This action includes distributed generation among the emergency response resources ERCOT may call upon to help stabilize the grid during emergencies.[13]

ERCOT has also announced that an additional 2,000 MW of capacity that had been mothballed or taken off-line for an indefinite period of time, will be back into service for the 2012 summer operating period.[14] This 2,000 MW of nameplate capacity (1,567 MW on-peak) includes approximately 430 MW of capacity that was not available during the 2011 summer operating period. These capacity enhancements increase the likelihood of ERCOT mitigating capacity reserve shortage for the 2012 summer without large scale system operator intervention to maintain reliability. However, these preparations have not yet increased the reserve capacity to a sufficient level. ERCOT's resource adequacy from 2013 through 2022 will be examined in greater depth in NERC's *2012 Long-Term Reliability Assessment*, expected to be published in November 2012.

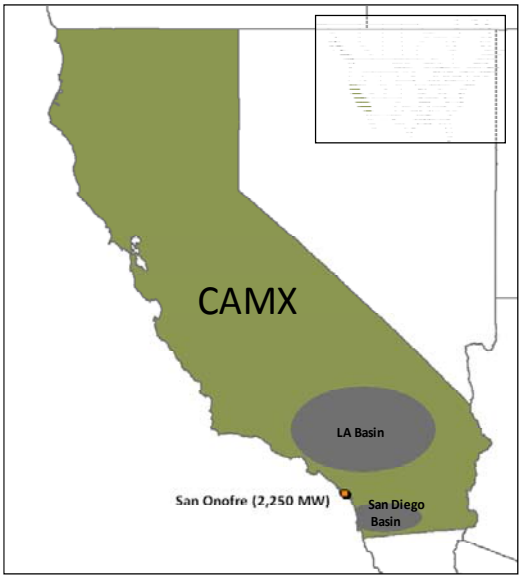
[12] NPRR450 authorized ERCOT to contract for generation and load resources to address emergency conditions. http://www.ercot.com/mktrules/issues/nprr/426-450/450/index

[13] NPRR451 also changes the name of ERCOT's Emergency Interruptible Load Service (EILS) to Emergency Response Service (ERS) to reflect recent PUC rulemaking (Substantive Rule 25.507), which seeks to improve reliability by offering ERCOT a more diverse set of tools to help prevent rotating outages or a potential blackout. http://www.ercot.com/mktrules/issues/nprr/451-475/451/index

[14] The 2,000 MW of returned mothballed generation is included in the reported available capacity (Existing-Certain) of 73,070 MW.

## The unanticipated outage of the San Onofre Nuclear Generating Station (SONGS) reduces available summer capacity; transmission ties critical to reliability of Southern California

On January 31, 2012, San Onofre Nuclear Generating Station (SONGS) Unit 3 was shut down due to indications of a leak in a steam generator tube. Subsequent inspections of steam generator tubes confirmed that there was a small leak on a single tube in one of the two steam generators. Continuing inspections of 100 percent of the steam generator tubes in both Unit 2 and Unit 3 steam generators identified 10 total steam generator tubes with reduced tube wall thicknesses from 90 to 28 percent of normal, which was classified as unexpected wear of tubes. As a precautionary measure, both Unit 2 and Unit 3 were taken offline to further investigate and resolve the identified problem. Progress is being monitored by federal, state, and local authorities, which includes staff from the US Nuclear Regulatory Commission and the California Energy Commission.




**15.2%**
WECC-CAMX-US Anticipated Reserve Margin

Technical studies conducted by the California Independent System Operator (CAISO) for the WECC-CAMX-US assessment area show tight reserve margins for San Diego and the Los Angeles Basin load center areas, especially during potential summer heat waves. Planning Reserve Margins are forecast to be approximately 0.1 percent above the NERC Reference Margin Level of 15.1 percent during the peak demand period of July 2012.[15]

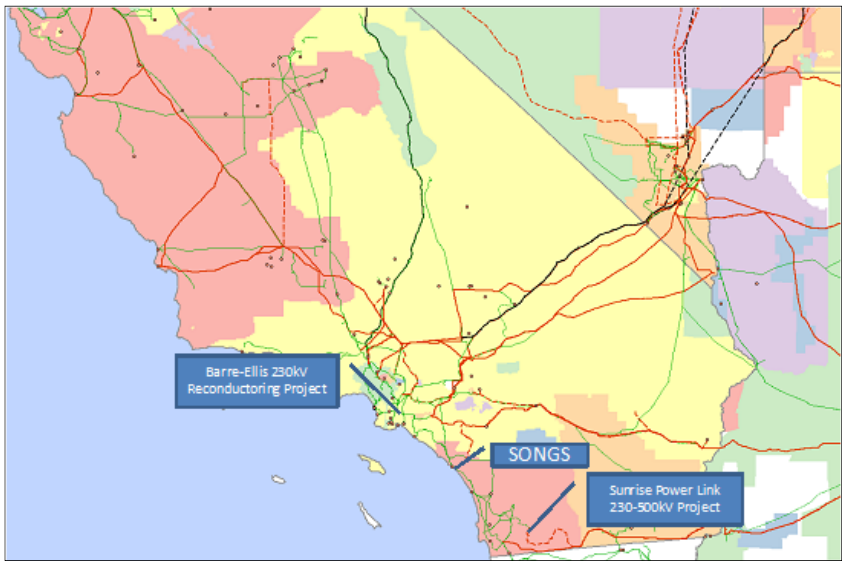
Contingency planning in CAISO includes the following mitigation strategies (as of publishing):

- Calling back into service the Huntington Beach Power Plant, previously slated for retirement. This not only adds 452 MW of capacity in the Los Angeles Basin, but will also enable 350 MW of additional imported power to transfer into the San Diego metropolitan area.
- Accelerating the completion of Barre-Ellis and Sunrise Powerlink transmission projects.
- Re-activating the 20/20 demand reduction program, Flex Alert TV and radio conservation campaign.
- Coordinating military and public agency conservation in key areas of Southern California to further reduce peak demand

In addition to conservation and demand response programs developed for specific local areas to mitigate the SONGS outage, CAISO will be able to tap about 2,296 MW of demand response and interruptible load programs to provide operational flexibility during periods of stress on the grid. Figure 6 shows the 2012 transmission enhancements in Southern California, while Figure 7 shows CAISO preparations to deal with the capacity shortage caused by the SONGS outage.

[15] This includes the scheduled outage of SONGS Units 2 and 3 (2,200 MW).

**Figure 6: 2012 CAMX-US Transmission Enhancements**




The addition of 926 MW of generation capacity – half of which is renewable generation capacity – is projected between the summer of 2011, through the end of the 2012 summer operating period (September 30, 2012).

At the time of publication, the latest estimate for the return to service of SONGS (in filings to the U.S. Nuclear Regulatory Commission) was September 1, 2012; however, recent reports indicate that no specific timeline exists.[16] If the estimated return to service is not accelerated, SONGS would return to service after the peak-demand period in WECC-CAMX-US of July 2012. This could pose operational challenges in Southern California and lead to situations in which there is an increased probability of Firm load shedding to maintain the reliable operation of the bulk power system.

**Figure 7: Preparations Yield Sufficient Planning Margins[17]**

Huntington Beach units 3 & 4 increase import capability to San Diego.

| Load | Mild Conditions | Heavy Load | Mild Conditions | Heavy Load |
|---|---|---|---|---|
| | 4438 | 4882 | 4438 | 4882 |
| Total gen | 3048 | 3048 | 3048 | 3048 |
| **Import capability** | **2100** | **2100** | **2450** | **2450** |
| Load can be served | 5148 | 5148 | 5498 | 5498 |
| Reserves available | 710 | 266 | 1060 | 616 |
| Reserve requirement | 603 | 603 | 603 | 603 |
| Reserve margin | 107 | -337 | 457 | 13 |

WECC resource adequacy and transmission modeling show sufficient transfer capability exists between Southern California and its neighboring areas, which in real-time should alleviate any capacity deficiencies within the San Diego and Los Angeles basins. The WECC Reliability Coordinator and CAISO continue to closely monitor developments in Southern California including the outage of the SONGS facility as well as other generation outages to ensure reliable operation of the bulk power system during the summer operating period.

In addition to the outages at SONGS, the Intermountain Generating Station (IGS) unit (900 MW), which also provides power to the Los Angeles Basin, has been forced out of service since December 2011. The IGS unit is undergoing repairs, and it is expected to return to service by the start of the summer operating period on June 1, 2012. At time of publishing, no other entities have reported long-term maintenance outages to WECC that may not finish on time or that could impact the reliability of the bulk power system.

[16] http://www.caiso.com/Documents/SCE_ISO-ClarifyPlanningDatesandProcessRegardingSanOnofre.pdf
[17] http://www.caiso.com/Documents/BriefingSummer2012OperationsPreparedness-Presentation-Mar2012.pdf

## Enhanced operations and planning approaches instituted in response to September 2011 southwest outage

During an 11 minute period on the afternoon of September 8, 2011, a system disturbance occurred in the Pacific Southwest, that lead to cascading outages, which left approximately 2.7 million customers without power. The outages affected parts of Arizona, Southern California, and Baja California, Mexico. The entire San Diego area was blacked out, with nearly one-and-a-half million customers impacted for up to 12 hours. The system is designed and operated to withstand the single largest contingency and operate reliably, even with an outage of a 500 kV transmission line as demonstrated on previous occasions.

**2.7 million**
Approximate number of customers impacted by 2011 outage

After the outages occurred, the impacted entities promptly instituted their respective restoration processes. The affected customer load was restored approximately 12 hours after the initiating event.

The September 8, 2011 event stemmed primarily from weaknesses in two areas: operations planning and real-time situational awareness. These same weaknesses were identified in the August 2003 blackout that affected an estimated 50 million people in the Northeastern United States and Canada. Without adequate operations studies and situational awareness, entities responsible for operating and overseeing the transmission system could not ensure reliable operations within System Operating Limits (SOLs) or prevent cascading outages in the event of a single contingency, such as the loss of a single transmission line.

With regard to operations planning, some of the impacted entities' seasonal, next-day, and real-time studies do not adequately consider: (1) operations of facilities in external networks, including the status of transmission facilities, expected generation output, and load forecasts; (2) external contingencies that could impact their systems or internal contingencies that could impact their neighbors' systems; and (3) the impact on bulk power system reliability of internal and external sub-100 kV facilities. As a result, these entities' operations studies did not accurately and fully predict the impact of the loss of transmission elements. If the impacted entities had more accurately predicted the magnitude of these contingencies prior to the event, appropriate pre-contingency measures, such as dispatching additional generation to mitigate overloads and prevent cascading outages, could have been taken.

The September 8th event also exposed some entities' lack of adequate real-time situational awareness of conditions and contingencies throughout the WECC Region. For example, many entities' real-time tools, such as State Estimator and Real-Time Contingency Analysis (RTCA), are restricted by models that do not accurately or fully reflect the facilities and operations of external networks. Also, some entities' real-time tools are not adequate to alert operators to significant conditions or potential contingencies on their systems or neighboring systems. The lack of adequate situational awareness limits entities' ability to identify and plan for the next most critical contingency to prevent instability, uncontrolled separation, or cascading outages. If some of the impacted entities had been aware of real-time external conditions and performed (or reviewed) studies on the conditions prior to the onset of the event on September 8, 2011, then they could have been better prepared for the impacts when the event started and avoided the cascading that ensued.

To improve situational awareness in the WECC region recommendations were made to: (1) expand entities' external visibility in their models through, for example, improved data sharing and expanded use of Inter-Control Center Communications Protocol (ICCP) data links or similar technology; (2) improve the use of real-time tools to ensure the constant monitoring of potential contingencies; and (3) improve communications between entities to help maintain situational awareness.

**27**
Number of specific recommendations in FERC/NERC Joint Inquiry Report

In addition to the operations planning and situational awareness issues, a host of other factors contributed to the September 8th event. For example, the WECC RC and impacted entities do not consistently recognize the adverse impact that sub-100 kV facilities can have on BPS reliability. Accordingly, the joint inquiry report recommended ensuring that facilities that can impact BPS reliability, regardless of voltage level, are classified as part of the bulk power system (BPS) and/or studied as part of entities' long-term and operations planning.

The joint inquiry report also found some significant issues with protection system planning and coordination. One recommendation was for Transmission Owners (TOs) to review their transformers' overload protection relay settings and philosophy within the context of prevailing industry practice, which applies settings in the range of 150 to 200 percent of the transformers' normal rating. TOs and transmission operators (TOP) should also plan to take proper pre-contingency mitigation measures before a facility loads to its tripping threshold and is automatically removed from service. The September event shows that all protection systems and separation schemes should be studied to understand their impact on BPS reliability and to ensure their operation or misoperation does not have unintended and undesirable effects.

In May 2012, NERC and the Federal Energy Regulatory Commission (FERC) jointly issued a report on the September 8, 2011 blackout.[18] The report identified 27 near, medium, and long-term recommendations that should be implemented in response to the lessons-learned from the investigation.

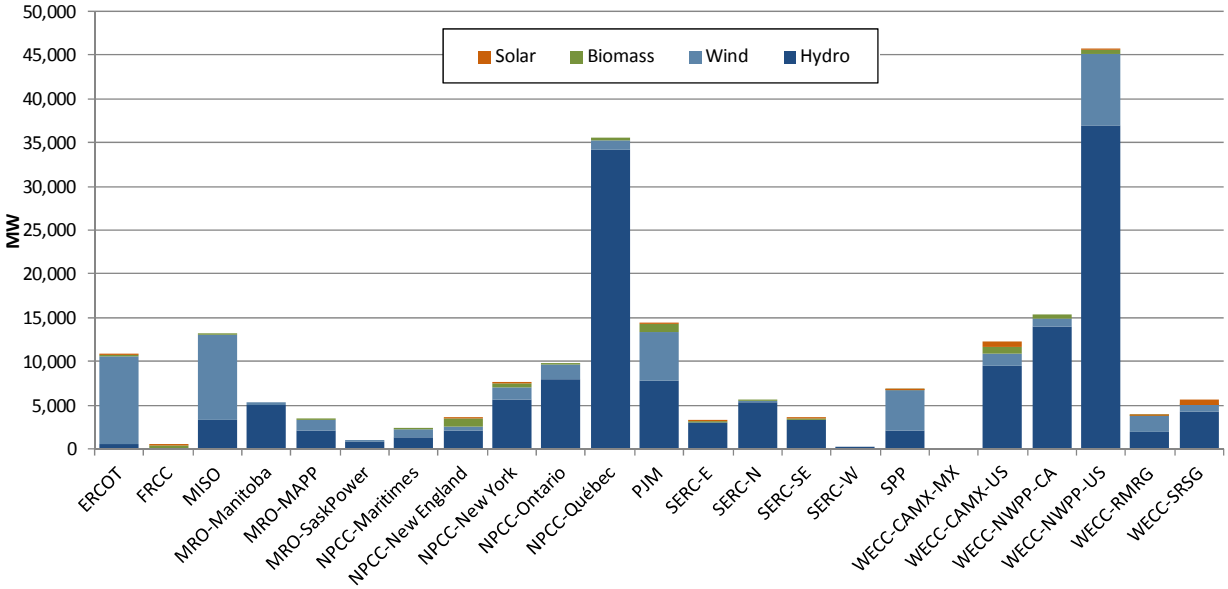
Several entities within WECC have taken, or are in the process of taking actions to prevent similar disturbances in the future. These actions include the implementation of additional real-time data exchange and coordination with additional entities in the Southwest. These processes will help facilitate a more detailed monitoring capability of neighboring systems in their energy management systems and real-time contingency analysis applications. In addition, the WECC RC has coordinated the development of an interim monitoring procedure of the San Diego and Imperial Valley areas with specific actions that will be taken for overload conditions.

[18] NERC – FERC Joint Inquiry Report into September 8, 2011 Arizona-California Outage http://www.nerc.com/fileUploads/File/News/AZOutage_Report_01MAY12.pdf.

## Variable generation continues to increase in most assessment areas

During the summer of 2012, variable generation is forecast to increase in most assessment areas across North America. Specifically, this assessment notes significant increases in nameplate wind capacity in MISO, ERCOT, and NPCC-New England (ISO-NE). Other forms of variable generation, such as solar and other renewables capacities are not expected to significantly increase during the 2012 summer operating period. Figure 8 shows the nameplate renewable capacity (biomass, hydro, solar, and wind) for the 2012 summer for all assessment areas. NERC-wide, a total of 4,576 MW of nameplate wind generation has been installed since last year, reflecting a modest increase of 1,880 MW of expected capacity on-peak.

**Figure 8: Nameplate Renewable Capacity for 2012 Summer**




Variable resources – especially wind – are growing in nameplate capacity and becoming an important portion of the generation mix in many areas of North America. It is vital to ensure that these variable resources are reliably integrated into the bulk power system, and that both planning and operational challenges are addressed.[19]

New technologies have decreased the cost of producing electricity from wind, and tax incentives for renewable energy, as well as the introduction of state and provincial renewable portfolio standards, has lead to subsequent growth in NERC-wide wind resources. Generation from wind in the United States alone increased from about 6 billion kilowatt-hours (kWh) in 2000 to approximately 120 billion kWh in 2011.

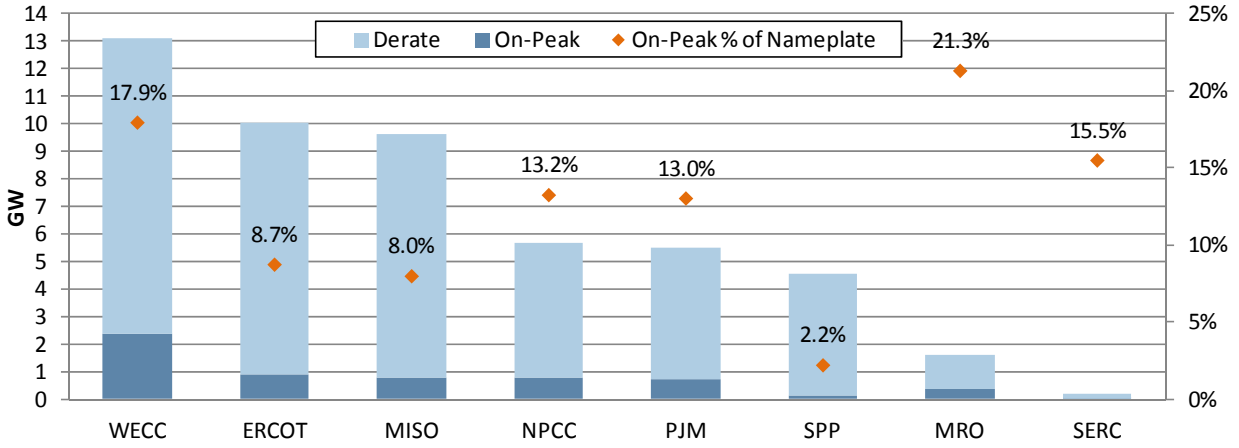
However, the actual capacity output of wind plants during times of peak demand generally amount to a fraction of nameplate capacity. Expected on-peak capacity typically accounts for between zero and 21.3 percent of an assessment area's entire nameplate wind capacity.[20] As noted by NERC in prior

[19] Accommodating High Levels of Variable Generation: Summary Report: http://www.nerc.com/files/Special%20Report%20%20Accommodating%20High%20Levels%20of%20Variable%20Generation.pdf.

[20] Within NPCC, the Quebec Assessment Area discounts wind 100 percent for summer on-peak capacity.

assessments, consistent methods to determine on-peak wind capacity are needed to ensure uniform measurement and resource adequacy assumptions.[21] As wind generation becomes a more significant contributor to an area's capacity mix, probabilistic planning techniques will be needed. More consistency is being achieved due to more experience with larger portfolios of wind generation. Figure 9 shows the nameplate and on-peak 2012 summer wind capacity expected output by assessment area.

**Figure 9: Nameplate and On-Peak Summer Wind Output by Major Assessment Areas**




Operationally, an increase in wind resources continues to challenge operators with the inherent swings, or ramps, in power output. In certain areas, where large concentrations of wind resources have been added, system planners must accommodate added variability by increasing the amount of available regulating reserves, and potentially carrying additional operating reserves. Because weather plays a key factor in determining wind output, enhancing Regional wind forecasting systems can provide more accurate output projections. Other methods include wind curtailment and limitation procedures used when generation exceeds the available regulating resources. In this respect, operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures and tools must be enhanced to assist operators in maintaining bulk power system reliability.

[21] Currently, Planning Coordinators use different methods to determine expected on-peak values of wind capacity. The Integration of Variable Generation Task Force is addressing this issue. The report *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* is available on the NERC website at: http://www.nerc.com/files/IVGTF1-2.pdf.

## Demand-side management key in maintaining reliability this summer

**100 %**
increase of expected on-peak demand response since 2006

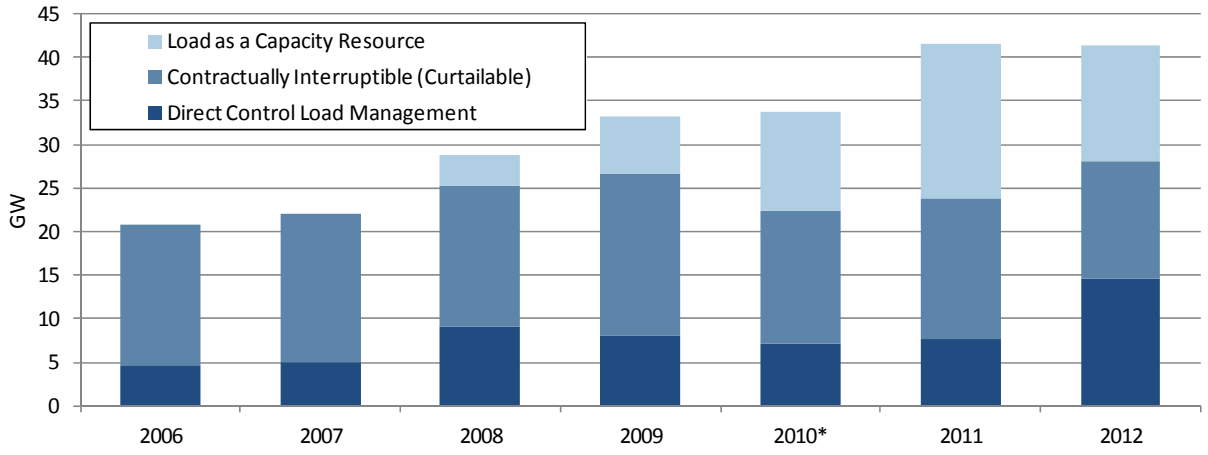
Demand-side management programs, which include conservation, energy efficiency, and a variety of demand response programs, provide the electric power industry the ability to reduce peak demand and to potentially defer the need for additional future generation or transmission. With tight margins in some areas, successful deployment of demand response will be critical for maintaining reliability this summer. Depending on summer conditions, demand response may be used more often this summer in areas with tight margins, such as Texas and Southern California.

Demand-side management is the term for activities or programs undertaken by a utility or an ISO/RTO with electricity end-users to influence the amount or timing of electricity they use. NERC collects controllable capacity demand response (CCDR) programs in four categories. These four types of demand response programs support reliability and are counted on to meet resource adequacy requirements.

- Direct Control Load Management (DCLM)
- Contractually Interruptible (Curtailable)
- Critical Peak Pricing (CPP) with Control[22]
- Load as a Capacity Resource

Demand response programs for this summer total approximately 40,200 MW for all of NERC.[23] Growth in demand response has slowed and actually decreased this summer compared to last summer's available capacity of approximately 41,500 MW, as shown in Figure 10. However, expected on-peak capacity for NERC overall has doubled since 2006.

**Figure 10: NERC-Wide Demand Response Projected On Peak**




*Reflects updated 2010 PJM data for Load as a Capacity Resource.

[22] Not shown below since this type of program has less than 100 MW of NERC-wide availability.

[23] Demand Response is not a shareable resource, but is largely used for local-area reliability within a single operating entity. The total NERC value is only a general indicator or reference for growth in demand response resources.

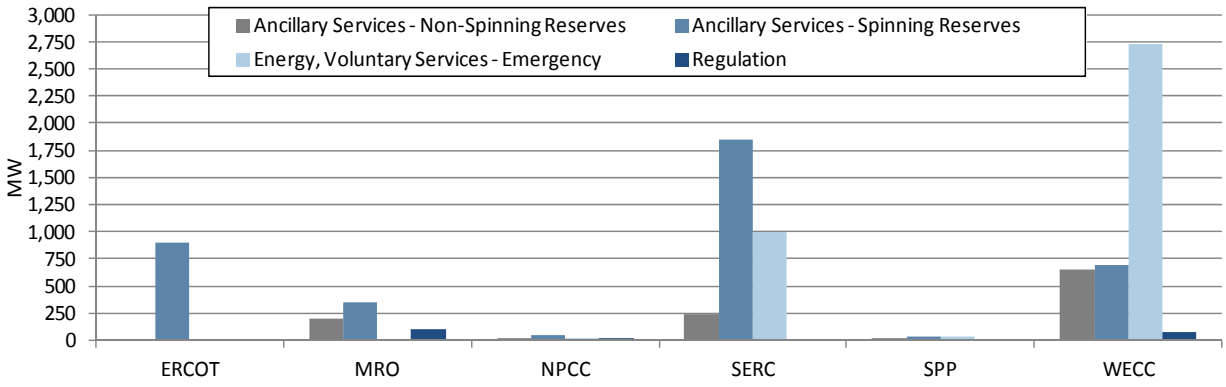
During the 2012 summer operating period, system operators may deploy demand response to either manage peak demand or to provide contingency reserves. Figure 11 shows available demand response capability across the North American bulk power system for the 2012 summer operating period. In almost all assessment areas, flat or slightly increased demand response participation is projected over the assessment timeframe. PJM and MISO administer the most demand response with 11,647 MW and 8,052 MW of demand response, respectively. These relatively large demand response participation values represent about 8 percent of the Total Internal Demand for each of the areas.

**Figure 11: 2011 and 2012 Summer Demand Response by Assessment Area**

| | 2011 Total DR | 2012 Total DR | Change (MW) | Demand-Side | Supply-Side |
|---|---|---|---|---|---|
| ERCOT | 1,433 | 1,471 | 38 | 1,471 | |
| FRCC | 3,141 | 3,183 | 42 | 3,183 | |
| MISO | 7,819 | 8,052 | 233 | 4,529 | 3,523 |
| MRO-Manitoba | 227 | 225 | -2 | | 225 |
| MRO-MAPP | 60 | 177 | 117 | 84 | 93 |
| MRO-SaskPower | 91 | 91 | 0 | 91 | |
| NPCC-Maritimes | 0 | 222 | 222 | | 222 |
| NPCC-New England (ISO-NE) | 2,535 | 2,106 | -429 | 978 | 1,128 |
| NPCC-New York (NYISO) | 2,053 | 2,165 | 112 | | 2,165 |
| NPCC-Ontario | 0 | 1,326 | 1,326 | | 1,326 |
| NPCC-Québec | 0 | 0 | 0 | | 0 |
| PJM | 11,600 | 11,647 | 47 | 11,647 | |
| SERC-E | 1,694 | 1,878 | 184 | 1,878 | |
| SERC-N | 1,915 | 1,536 | -379 | 1,536 | |
| SERC-SE | 1,704 | 1,774 | 70 | 1,774 | |
| SERC-W | 873 | 11 | -862 | 11 | |
| SPP | 1,252 | 1,136 | -115 | 1,136 | |
| WECC-CAMX-MX | 0 | 0 | 0 | | 0 |
| WECC-CAMX-US | 2,204 | 2,211 | 7 | 2,211 | |
| WECC-NWPP-CA | 22 | 12 | -10 | 12 | |
| WECC-NWPP-US | 1,256 | 1,225 | -31 | 1,225 | |
| WECC-RMRG | 408 | 447 | 39 | 447 | |
| WECC-SRSG | 449 | 512 | 63 | 512 | |

Additional flexibility is provided to operators who facilitate the use of demand response resources to support local reliability issues and other system constraints as needed. For example, demand response is being used more and more to provide ancillary services, though these programs are still in their infancy and only a small amount of capacity provides these services, shown in Figure 12. Technological improvements in activation methods, as well as measurement and verification reinforce operator's confidence in demand resources in providing fast-acting response when grid conditions are stressed.

**Figure 12: Demand Response Used to Provide Ancillary Services**



## The impact of potentially extreme weather events on bulk power system reliability

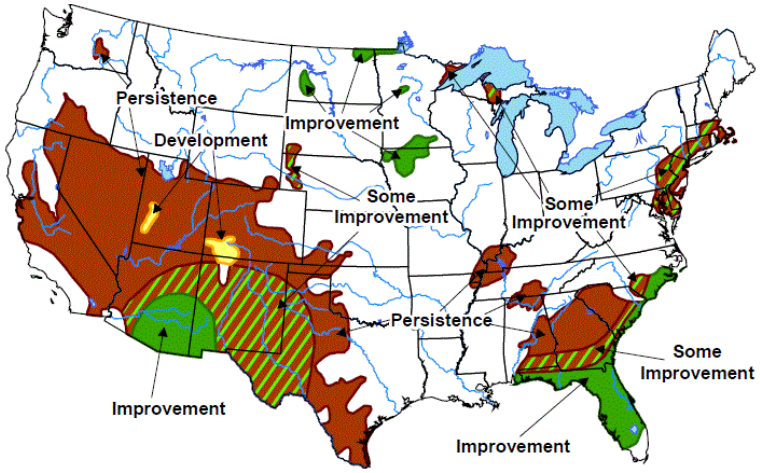
Extreme weather is based on an event's climatologically expected distribution.[24] For example, an event is called extreme in this sense if it lies in the tails of the climatological distribution, occurring less than 5 percent of the time.[25] Extreme events, by definition, are rare. Weather experienced during the 2010/2011 winter in Texas serves as an example of extreme weather, when temperatures dropped to a level that does not often occur.[26] The prolonged and extreme temperatures in Texas significantly stressed the power system, which resulted in the calling of two "Alert 2" level Energy Emergency Alerts (EEAs).[27]

For the purposes of this assessment, no attempt was made to forecast or predict the occurrence of extreme events such as extreme temperatures, precipitation, or development of extreme drought conditions. Instead, NERC identifies and highlight forecast observations that may have an impact on the reliable operation of the bulk power system. On-going trends, such as drought throughout the southwestern United States, are not expected to be a major factor during the 2012 summer, though still in the range of possibilities of impacting operations.

***Drought***

Overall, the current drought outlook from the National Oceanic and Atmospheric Administration (NOAA) is not optimistic for the 2012 summer operating period.[28] Substantial improvement is expected only in southern New England, the southern half of Florida with the onset of its rainy season, western North Dakota, and the Southwest. Drought should persist where it exists today and may expand to cover the central Rockies. Overall, there appears to be a generally low risk of large amounts of generator derates or outages this summer due to water availability. Figure 13 shows the latest drought outlook by NOAA.

**Figure 13: U.S. Seasonal Drought Outlook**




*Valid: May 17, 2012 through August 31, 2012*

| |
|---|
| Brown |
| Drought to persist or intensify |
| Brown and Green |
| Drought ongoing, some improvement |
| Green |
| Drought likely to improve, impacts ease |
| Yellow |
| Drought development likely |

*Source: NOAA Climate Prediction Center*

[24] Climate is defined as the weather conditions prevailing in an area in general or over a long period.

[25] Extreme Weather Events and their Probabilistic Prediction by the NCEP Ensemble Forecast System, Yuejian Zhu[1] and Zoltan Toth http://www.emc.ncep.noaa.gov/gmb/ens/target/ens/albapr/albapr.html

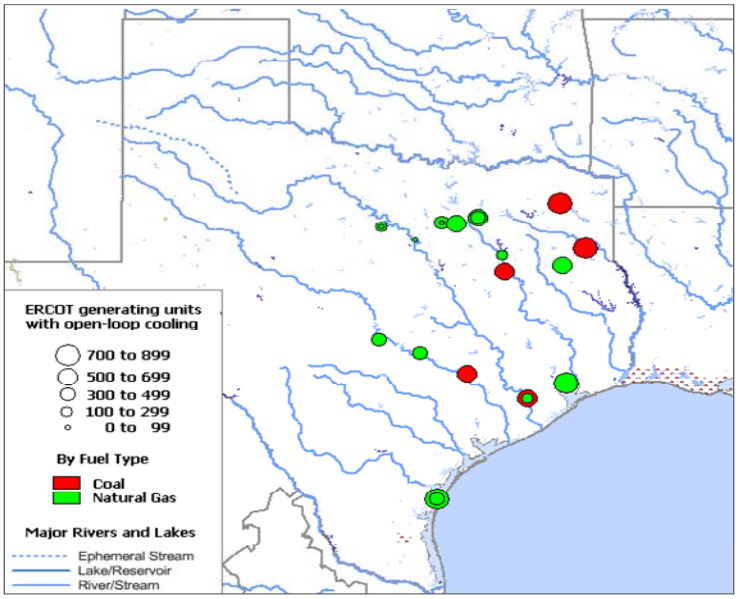
[26] http://www.nerc.com/files/SW_Cold_Weather_Event_Final_Report.pdf

[27] http://www.nerc.com/page.php?cid=4|331|341 and http://www.nerc.com/page.php?cid=4|331|335

[28] The NOAA drought outlook is based on short, medium, and long-range forecasts, initial conditions, past years with similarly-evolving weather, equatorial Pacific sea surface temperature patterns, objective weather and climate model output, and climatology.

During late summer in ERCOT, 85 percent of Texas was in "Exceptional Drought" status. However, recent precipitation in the eastern portion of Texas have improved rainfall deficits and the latest information from ERCOT indicate significant impacts caused by drought conditions are less likely. Further, a majority of the larger generation units that require cooling water are located in eastern Texas where drought conditions are not a concern, as shown in Figure 14. Conversely, the Brazos and Sabine River basins in the east and south are experiencing more persistent drought conditions. ERCOT will continue to monitor reservoir levels and the potential impact on the availability of once-through or open-loop cooling water-dependent generation.

**Figure 14: ERCOT Generating Units with Open-Loop Cooling and Large Average Withdrawals**




While water planning is not a function of ERCOT, significant steps have been taken to minimize the risk of generator outages and derates such as implementing water conservations programs, optimization of water reuse and recycling, minimizing water consumption, and using gray or lower quality water for cooling. In more extreme cases, intake structures could be modified to increase the relative water head levels from the pump intakes. Earlier this year, ERCOT held a *Drought Best Practices Workshop,*[29] which brought area stakeholders together to discuss mitigation measures that can be applied to minimize drought impacts.

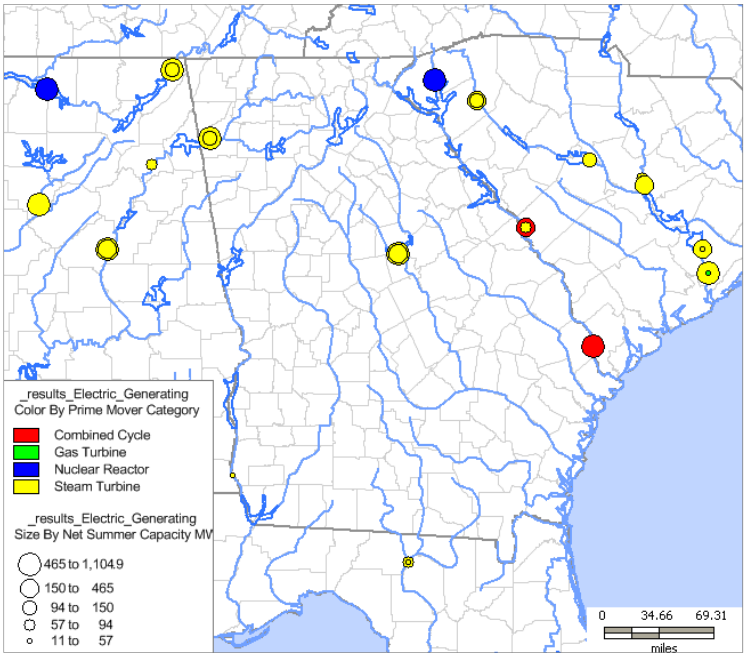
Some persistent drought conditions could also impact WECC. The western areas experienced a relatively warm and dry 2011/2012 winter, resulting in sparse snow pack in some areas. Runoff forecasts for the California basins are at or below 1/3 of normal conditions, while the Colorado River Basin is in its 12th year of a persistent drought. However, a March Columbia River flow forecast was at 93 percent of the 30-year average flow, measured at The Dalles, Oregon. It is expected that reduced river flows will result in increased thermal-based energy generation, but will not significantly impact the ability to serve peak demand.[30]

[29] http://www.ercot.com/calendar/2012/02/20120227-OTHER

[30] WECC models use a stress case, which includes adverse hydro conditions, to assess resource adequacy and power flows across the Western Interconnection.

Persistent drought conditions are also affecting the southeast states of Alabama, Georgia, and South Carolina (portions of the SERC-SE and SERC-E Assessment Areas). Within these three states, approximately 19,000 MW of generation within the drought affected areas require open-loop cooling, shown in Figure 15.[31] Additionally, just over 4,000 MW of on-peak hydro capacity is also in this area. Significant derates and/or complete unit outages due to a lack of cooling water could expose the southeastern areas to capacity shortages in extreme scenarios; however, reserve margins in these areas are more than sufficient to provide system operators with alternative resources should reservoir water levels fall significantly.

**Figure 15: Southeast Generating Units with Open-Loop Cooling and Large Average Withdrawals**




***Temperature***

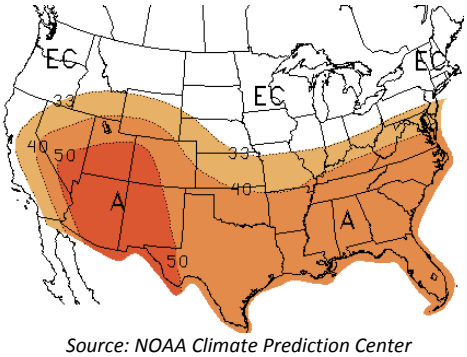
The temperature outlook for this summer indicates an increased probability of below normal mean temperatures in the Great Plains area of the United States, as indicated by NOAA models and tools.[32] Probabilities of above normal mean temperatures exist in the WECC-SRSG, ERCOT, all areas of SERC, PJM, and FRCC.

The entirety of Canada is currently forecast to be above normal mean temperatures for the months of June, July and August. However, there is significant reserve capacity available to meet increasing demand in all Canadian provinces. U.S. and Canada temperature forecasts are shown in Figure 16 and Figure 17.

[31] Excludes units located on the Atlantic Ocean coast.

[32] The climatic normal are based on conditions between 1981 and 2011, following the World Meteorological Organization convention of using the most recent three (3) decades as the climatic reference period. The probability anomalies for temperature and precipitation based on these new normal better represent short term climatic anomalies than the forecasts based on older baselines (temperature and precipitation).

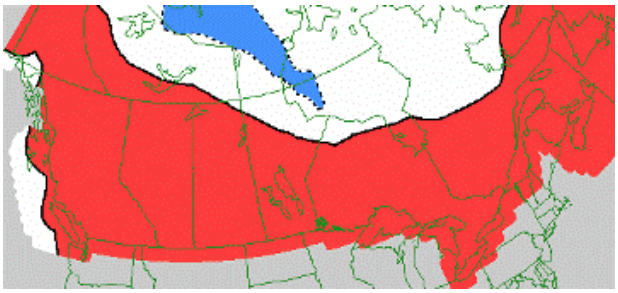
**Figure 16: U.S. Summer Mean Temperature Probability Outlook, June to August 2012**[33]




*Source: NOAA Climate Prediction Center*

| | |
|---|---|
| A (Orange) | Above-Normal Temperatures Forecast |
| EC (White) | Equal Chance of Above- or Below-Normal Temperatures |
| B (Blue) | Below-Normal Temperatures Forecast |

**Figure 17: Canada Summer Mean Temperature Probability Outlook, June to August 2012**[34]



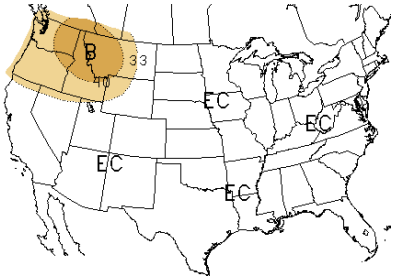
*Source: Environment Canada*

| | |
|---|---|
| Red | Above-Normal Temperatures Forecast |
| White | Equal Chance of Above- or Below-Normal Temperatures |
| Blue | Below-Normal Temperatures Forecast |

***Precipitation***

Summer precipitation outlooks are based on decadal climate variability and trends. Probabilities of below median precipitation are increased for portions of the Pacific Northwest. The remainder of the U.S. is expected to have average precipitation throughout the summer months. In Canada, below average precipitation levels are predicted across a number of Canadian provinces. A lack of significant precipitation during the 2012 summer months should not have an impact on resource adequacy for the summer operating period, but could have a resource adequacy impact of hydro generation-dependent areas for the 2012/2013 winter operating period. Precipitation forecasts for the U.S. and Canada are shown in Figure 18 and Figure 19.

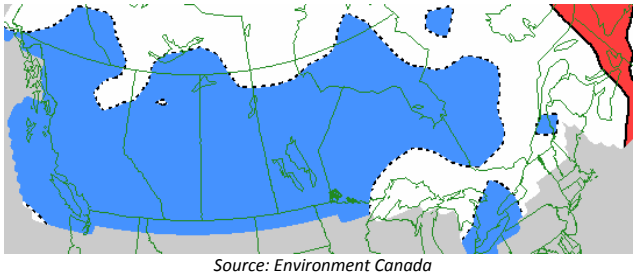
**Figure 18: U.S. Summer Mean Precipitation Outlook, June to August 2012**




*Source: NOAA Climate Prediction Center*

| | |
|---|---|
| A (Green) | Above-normal Precipitation Forecast |
| EC (White) | Equal Chance of Above- or Below-Normal Precipitation |
| B (Brown) | Below-Normal Precipitation Forecast |

**Figure 19: Canada Mean Summer Precipitation Outlook, June to August 2012**



*Source: Environment Canada*

| | |
|---|---|
| Red | Above-normal Precipitation Forecast |
| White | Equal Chance of Above- or Below-Normal Precipitation |
| Blue | Below-normal Precipitation Forecast |

[33] http://www.cpc.ncep.noaa.gov/index.php

[34] http://www.weatheroffice.gc.ca/saisons/index_e.html

## Lower global LNG gas supply may impact LNG-dependent generation in New England; ISO to implement proactive measures

Under normal weather and system conditions, New England's electric power supplies are expected to be adequate to meet regional demand this summer. However, reduced and uncertain supplies of liquefied natural gas (LNG) to power generation in the Northeast Massachusetts/Greater Boston area during the summer could create local reliability challenges to this portion of the power grid. Extreme weather conditions combined with significant unexpected generator outages could further stress the situation.

With below-normal LNG supplies to New England, system operators from ISO-NE are working with local stakeholders along with federal, state, and local authorities to mitigate impacts for the 2012 summer. While these solutions will help minimize impacts this summer, a long-term solutions are currently being developed to address fuel diversity and resource availability issues.

# Projected Demand, Resources, and Reserve Margins

### NERC Assessment Area Reserve Margins for the 2012 Summer Peak Month[35]

| Country / Assessment Area | Demand | | Capacity Resources | | | Planning Reserve Margins | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Total Internal | Net Internal | Existing-Certain & Net Firm | Anticipated | Prospective | Existing-Certain & Net Firm | Anticipated | Prospective | Reference Level |
| | (MW) | (MW) | (MW) | (MW) | (MW) | (%) | (%) | (%) | (%) |
| ERCOT | 66,076 | 64,605 | 73,211 | 73,334 | 73,334 | 13.32% | 13.51% | 13.51% | 13.75% |
| FRCC | 45,613 | 42,430 | 54,986 | 54,241 | 54,297 | 29.59% | 27.84% | 27.97% | 15.00% |
| MISO | 93,102 | 88,573 | 112,285 | 113,952 | 127,299 | 26.77% | 28.65% | 43.72% | 16.70% |
| MRO-MAPP | 4,799 | 4,715 | 5,788 | 6,082 | 6,082 | 22.77% | 29.01% | 29.01% | 15.00% |
| NPCC-New England (ISO-NE) | 27,440 | 26,462 | 33,448 | 33,585 | 34,815 | 26.40% | 26.92% | 31.57% | 15.00% |
| NPCC-New York (NYISO) | 33,295 | 33,295 | 39,024 | 39,024 | 39,024 | 17.21% | 17.21% | 17.21% | 16.00% |
| PJM | 153,782 | 142,135 | 185,641 | 185,641 | 190,471 | 30.61% | 30.61% | 34.01% | 15.60% |
| SERC-E | 43,255 | 41,378 | 50,696 | 50,696 | 50,696 | 22.52% | 22.52% | 22.52% | 15.00% |
| SERC-N | 45,102 | 43,566 | 57,079 | 57,957 | 59,445 | 31.02% | 33.03% | 36.45% | 15.00% |
| SERC-SE | 48,895 | 47,121 | 62,833 | 62,883 | 64,799 | 33.34% | 33.45% | 37.52% | 15.00% |
| SERC-W | 25,403 | 25,392 | 34,591 | 36,569 | 37,443 | 36.23% | 44.02% | 47.46% | 15.00% |
| SPP | 54,051 | 52,915 | 63,549 | 64,908 | 71,831 | 20.10% | 22.66% | 35.75% | 13.60% |
| WECC-CAMX | 49,490 | 47,279 | 54,402 | 54,478 | 54,478 | 15.07% | 15.23% | 15.23% | 15.13% |
| WECC-NWPP | 41,523 | 40,298 | 47,038 | 47,708 | 47,708 | 16.73% | 18.39% | 18.39% | 15.67% |
| WECC-RMRG | 10,503 | 10,056 | 13,495 | 13,875 | 13,875 | 34.20% | 37.97% | 37.97% | 14.70% |
| WECC-SRSG | 29,402 | 28,890 | 35,208 | 35,388 | 35,388 | 21.87% | 22.49% | 22.49% | 13.50% |
| **TOTAL-UNITED STATES** | **771,732** | **739,110** | **923,274** | **930,321** | **960,985** | **24.92%** | **25.87%** | **30.02%** | **15.00%** |
| | | | | | | | | | |
| MRO-Manitoba Hydro | 3,143 | 3,143 | 4,296 | 4,516 | 4,641 | 36.68% | 43.68% | 47.66% | 12.00% |
| MRO-SaskPower | 3,044 | 2,953 | 3,647 | 3,647 | 3,888 | 23.50% | 23.50% | 31.68% | 13.00% |
| NPCC-Maritimes | 3,392 | 3,392 | 4,821 | 4,821 | 4,821 | 42.13% | 42.13% | 42.13% | 15.00% |
| NPCC-Ontario (IESO) | 23,409 | 23,409 | 29,281 | 30,451 | 36,735 | 25.08% | 30.08% | 56.92% | 20.40% |
| NPCC-Québec | 20,988 | 20,988 | 32,582 | 32,356 | 32,356 | 55.24% | 54.16% | 54.16% | 10.00% |
| WECC-NWPP | 17,769 | 17,757 | 26,597 | 26,627 | 26,627 | 49.78% | 49.95% | 49.95% | 12.36% |
| **TOTAL-CANADA** | **71,745** | **71,642** | **101,223** | **102,417** | **109,067** | **41.29%** | **42.96%** | **52.24%** | **10.00%** |
| | | | | | | | | | |
| **TOTAL-MÉXICO** | **2,264** | **2,264** | **2,763** | **2,763** | **2,763** | **22.04%** | **22.04%** | **22.04%** | **11.86%** |
| | | | | | | | | | |
| **TOTAL-NERC** | **843,962** | **811,237** | **1,021,614** | **1,029,890** | **1,067,204** | **25.93%** | **26.95%** | **31.55%** | **15.00%** |
| | | | | | | | | | |
| **EASTERN INTERCONNECTION** | **607,725** | **580,878** | **741,965** | **748,972** | **786,286** | **27.73%** | **28.94%** | **35.36%** | **15.00%** |
| **ERCOT INTERCONNECTION** | **66,076** | **64,605** | **73,211** | **73,334** | **73,334** | **13.32%** | **13.51%** | **13.51%** | **13.75%** |
| **QUÉBEC INTERCONNECTION** | **20,988** | **20,988** | **32,582** | **32,356** | **32,356** | **55.24%** | **54.16%** | **54.16%** | **10.00%** |
| **WESTERN INTERCONNECTION** | **149,173** | **144,766** | **173,855** | **175,228** | **175,228** | **20.09%** | **21.04%** | **21.04%** | **15.00%** |

[35] This table reflects the non-coincidental NERC-wide peak, with Total Internal Demand projection for the peak month of each assessment area during the 2012 summer. The following four tables include the monthly projections for June, July, August and September. For additional information, please refer to Appendix V.

## NERC Assessment Area Reserve Margins for June 2012

| Country / Assessment Area | Demand | | Capacity Resources | | | Planning Reserve Margins | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Total Internal | Net Internal | Existing-Certain & Net Firm | Anticipated | Prospective | Existing-Certain & Net Firm | Anticipated | Prospective | Reference Level |
| | (MW) | (MW) | (MW) | (MW) | (MW) | (%) | (%) | (%) | (%) |
| ERCOT | 59,841 | 58,370 | 73,211 | 73,334 | 73,334 | 25.43% | 25.64% | 25.64% | 13.75% |
| FRCC | 42,589 | 39,459 | 54,986 | 54,986 | 55,042 | 39.35% | 39.35% | 39.49% | 15.00% |
| MISO | 86,548 | 82,019 | 111,407 | 113,072 | 127,291 | 35.83% | 37.86% | 55.20% | 16.70% |
| MRO-MAPP | 4,466 | 4,382 | 5,818 | 6,112 | 6,112 | 32.78% | 39.49% | 39.49% | 15.00% |
| NPCC-New England (ISO-NE) | 25,854 | 24,876 | 33,471 | 33,608 | 34,815 | 34.55% | 35.10% | 39.95% | 15.00% |
| NPCC-New York (NYISO) | 33,295 | 33,295 | 38,953 | 38,953 | 38,953 | 16.99% | 16.99% | 16.99% | 16.00% |
| PJM | 143,028 | 131,381 | 185,641 | 185,641 | 190,471 | 41.30% | 41.30% | 44.98% | 15.60% |
| SERC-E | 41,324 | 39,451 | 50,696 | 50,696 | 50,696 | 28.50% | 28.50% | 28.50% | 15.00% |
| SERC-N | 42,005 | 40,940 | 57,079 | 57,957 | 59,459 | 39.42% | 41.57% | 45.24% | 15.00% |
| SERC-SE | 46,732 | 44,969 | 62,833 | 62,883 | 64,749 | 39.72% | 39.84% | 43.99% | 15.00% |
| SERC-W | 23,041 | 23,030 | 34,591 | 36,569 | 37,500 | 50.20% | 58.79% | 62.83% | 15.00% |
| SPP | 49,697 | 48,730 | 63,549 | 64,654 | 71,577 | 30.41% | 32.68% | 46.88% | 13.60% |
| WECC-CAMX | 45,313 | 43,102 | 53,374 | 53,437 | 53,437 | 23.83% | 23.98% | 23.98% | 15.13% |
| WECC-NWPP | 38,540 | 37,315 | 46,035 | 46,710 | 46,710 | 23.37% | 25.18% | 25.18% | 15.67% |
| WECC-RMRG | 10,503 | 10,056 | 13,495 | 13,875 | 13,875 | 34.20% | 37.97% | 37.97% | 14.70% |
| WECC-SRSG | 26,933 | 26,421 | 41,595 | 41,753 | 41,753 | 57.43% | 58.03% | 58.03% | 13.50% |
| **TOTAL-UNITED STATES** | **719,709** | **687,796** | **926,733** | **934,240** | **965,774** | **34.74%** | **35.83%** | **40.42%** | **15.00%** |
| | | | | | | | | | |
| MRO-Manitoba Hydro | 3,079 | 3,079 | 3,911 | 3,997 | 4,122 | 27.02% | 29.81% | 33.87% | 12.00% |
| MRO-SaskPower | 3,044 | 2,953 | 3,669 | 3,669 | 3,907 | 24.27% | 24.27% | 32.31% | 13.00% |
| NPCC-Maritimes | 3,315 | 3,315 | 3,826 | 3,826 | 3,826 | 15.41% | 15.41% | 15.41% | 15.00% |
| NPCC-Ontario (IESO) | 22,769 | 22,769 | 29,551 | 29,971 | 35,985 | 29.79% | 31.63% | 58.04% | 20.40% |
| NPCC-Québec | 20,439 | 20,439 | 31,784 | 31,508 | 31,508 | 55.51% | 54.16% | 54.16% | 10.00% |
| WECC-NWPP | 17,769 | 17,757 | 26,597 | 26,627 | 26,627 | 49.78% | 49.95% | 49.95% | 12.36% |
| **TOTAL-CANADA** | **70,415** | **70,312** | **99,338** | **99,598** | **105,974** | **41.28%** | **41.65%** | **50.72%** | **10.00%** |
| | | | | | | | | | |
| **TOTAL-MÉXICO** | **1,992** | **1,992** | **2,522** | **2,522** | **2,522** | **26.61%** | **26.61%** | **26.61%** | **11.86%** |
| | | | | | | | | | |
| **TOTAL-NERC** | **792,115** | **760,100** | **1,024,679** | **1,032,435** | **1,070,345** | **34.81%** | **35.83%** | **40.82%** | **15.00%** |
| | | | | | | | | | |
| **EASTERN INTERCONNECTION** | **570,785** | **544,648** | **739,982** | **746,595** | **784,504** | **35.86%** | **37.08%** | **44.04%** | **15.00%** |
| **ERCOT INTERCONNECTION** | **59,841** | **58,370** | **73,211** | **73,334** | **73,334** | **25.43%** | **25.64%** | **25.64%** | **13.75%** |
| **QUÉBEC INTERCONNECTION** | **20,439** | **20,439** | **31,784** | **31,508** | **31,508** | **55.51%** | **54.16%** | **54.16%** | **10.00%** |
| **WESTERN INTERCONNECTION** | **141,050** | **136,643** | **179,703** | **180,999** | **180,999** | **31.51%** | **32.46%** | **32.46%** | **15.00%** |

## NERC Assessment Area Reserve Margins for July 2012

| Country / Assessment Area | Demand | | Capacity Resources | | | Planning Reserve Margins | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Total Internal | Net Internal | Existing-Certain & Net Firm | Anticipated | Prospective | Existing-Certain & Net Firm | Anticipated | Prospective | Reference Level |
| | (MW) | (MW) | (MW) | (MW) | (MW) | (%) | (%) | (%) | (%) |
| ERCOT | 60,696 | 59,225 | 73,211 | 73,334 | 73,334 | 23.62% | 23.82% | 23.82% | 13.75% |
| FRCC | 43,780 | 40,632 | 54,986 | 54,986 | 55,042 | 35.33% | 35.33% | 35.46% | 15.00% |
| MISO | 93,102 | 88,573 | 112,285 | 113,952 | 127,299 | 26.77% | 28.65% | 43.72% | 16.70% |
| MRO-MAPP | 4,799 | 4,715 | 5,788 | 6,082 | 6,082 | 22.77% | 29.01% | 29.01% | 15.00% |
| NPCC-New England (ISO-NE) | 27,440 | 26,462 | 33,448 | 33,585 | 34,815 | 26.40% | 26.92% | 31.57% | 15.00% |
| NPCC-New York (NYISO) | 33,295 | 33,295 | 39,024 | 39,024 | 39,024 | 17.21% | 17.21% | 17.21% | 16.00% |
| PJM | 153,782 | 142,135 | 185,641 | 185,641 | 190,471 | 30.61% | 30.61% | 34.01% | 15.60% |
| SERC-E | 43,255 | 41,378 | 50,696 | 50,696 | 50,696 | 22.52% | 22.52% | 22.52% | 15.00% |
| SERC-N | 44,221 | 42,822 | 57,079 | 57,957 | 59,445 | 33.29% | 35.34% | 38.82% | 15.00% |
| SERC-SE | 48,676 | 46,901 | 62,833 | 62,883 | 64,749 | 33.97% | 34.08% | 38.05% | 15.00% |
| SERC-W | 24,037 | 24,026 | 34,591 | 36,569 | 37,386 | 43.97% | 52.21% | 55.61% | 15.00% |
| SPP | 53,877 | 52,745 | 63,552 | 65,008 | 71,932 | 20.49% | 23.25% | 36.38% | 13.60% |
| WECC-CAMX | 49,490 | 47,279 | 54,402 | 54,478 | 54,478 | 15.07% | 15.23% | 15.23% | 15.13% |
| WECC-NWPP | 41,523 | 40,298 | 47,038 | 47,708 | 47,708 | 16.73% | 18.39% | 18.39% | 15.67% |
| WECC-RMRG | 9,949 | 9,502 | 11,853 | 12,233 | 12,233 | 24.74% | 28.74% | 28.74% | 14.70% |
| WECC-SRSG | 28,310 | 27,798 | 38,610 | 38,782 | 38,782 | 38.89% | 39.51% | 39.51% | 13.50% |
| **TOTAL-UNITED STATES** | **760,232** | **727,786** | **925,038** | **932,918** | **963,476** | **27.10%** | **28.19%** | **32.38%** | **15.00%** |
| | | | | | | | | | |
| MRO-Manitoba Hydro | 3,098 | 3,098 | 4,304 | 4,464 | 4,589 | 38.93% | 44.09% | 48.13% | 12.00% |
| MRO-SaskPower | 3,044 | 2,953 | 3,647 | 3,647 | 3,888 | 23.50% | 23.50% | 31.68% | 13.00% |
| NPCC-Maritimes | 3,211 | 3,211 | 4,545 | 4,545 | 4,545 | 41.54% | 41.54% | 41.54% | 15.00% |
| NPCC-Ontario (IESO) | 23,409 | 23,409 | 29,281 | 30,451 | 36,735 | 25.08% | 30.08% | 56.92% | 20.40% |
| NPCC-Québec | 20,551 | 20,551 | 31,437 | 31,211 | 31,211 | 52.97% | 51.87% | 51.87% | 10.00% |
| WECC-NWPP | 17,755 | 17,743 | 24,457 | 24,532 | 24,532 | 37.84% | 38.26% | 38.26% | 12.36% |
| **TOTAL-CANADA** | **71,068** | **70,965** | **97,671** | **98,849** | **105,499** | **37.63%** | **39.29%** | **48.66%** | **10.00%** |
| | | | | | | | | | |
| **TOTAL-MÉXICO** | **2,146** | **2,146** | **2,570** | **2,570** | **2,570** | **19.75%** | **19.75%** | **19.75%** | **11.86%** |
| | | | | | | | | | |
| **TOTAL-NERC** | **833,446** | **800,897** | **1,020,204** | **1,029,263** | **1,066,470** | **27.38%** | **28.51%** | **33.16%** | **15.00%** |
| | | | | | | | | | |
| **EASTERN INTERCONNECTION** | **603,026** | **576,355** | **741,701** | **749,490** | **786,697** | **28.69%** | **30.04%** | **36.50%** | **15.00%** |
| **ERCOT INTERCONNECTION** | **60,696** | **59,225** | **73,211** | **73,334** | **73,334** | **23.62%** | **23.82%** | **23.82%** | **13.75%** |
| **QUÉBEC INTERCONNECTION** | **20,551** | **20,551** | **31,437** | **31,211** | **31,211** | **52.97%** | **51.87%** | **51.87%** | **10.00%** |
| **WESTERN INTERCONNECTION** | **149,173** | **144,766** | **173,855** | **175,228** | **175,228** | **20.09%** | **21.04%** | **21.04%** | **15.00%** |

## NERC Assessment Area Reserve Margins for August 2012

| Country / Assessment Area | Demand | | Capacity Resources | | | Planning Reserve Margins | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Total Internal | Net Internal | Existing-Certain & Net Firm | Anticipated | Prospective | Existing-Certain & Net Firm | Anticipated | Prospective | Reference Level |
| | (MW) | (MW) | (MW) | (MW) | (MW) | (%) | (%) | (%) | (%) |
| ERCOT | 66,076 | 64,605 | 73,211 | 73,334 | 73,334 | 13.32% | 13.51% | 13.51% | 13.75% |
| FRCC | 45,613 | 42,430 | 54,986 | 54,241 | 54,297 | 29.59% | 27.84% | 27.97% | 15.00% |
| MISO | 91,839 | 87,310 | 113,165 | 114,834 | 127,301 | 29.61% | 31.52% | 45.80% | 16.70% |
| MRO-MAPP | 4,725 | 4,641 | 5,830 | 6,124 | 6,124 | 25.60% | 31.94% | 31.94% | 15.00% |
| NPCC-New England (ISO-NE) | 27,440 | 26,462 | 33,484 | 33,621 | 34,815 | 26.54% | 27.05% | 31.57% | 15.00% |
| NPCC-New York (NYISO) | 33,295 | 33,295 | 39,024 | 39,024 | 39,024 | 17.21% | 17.21% | 17.21% | 16.00% |
| PJM | 147,557 | 135,910 | 185,641 | 185,641 | 190,471 | 36.59% | 36.59% | 40.14% | 15.60% |
| SERC-E | 42,816 | 40,931 | 50,696 | 51,521 | 51,521 | 23.86% | 25.87% | 25.87% | 15.00% |
| SERC-N | 45,102 | 43,566 | 57,079 | 57,957 | 59,445 | 31.02% | 33.03% | 36.45% | 15.00% |
| SERC-SE | 48,895 | 47,121 | 62,833 | 62,883 | 64,799 | 33.34% | 33.45% | 37.52% | 15.00% |
| SERC-W | 25,403 | 25,392 | 34,591 | 36,569 | 37,443 | 36.23% | 44.02% | 47.46% | 15.00% |
| SPP | 54,051 | 52,915 | 63,549 | 64,908 | 71,831 | 20.10% | 22.66% | 35.75% | 13.60% |
| WECC-CAMX | 44,690 | 42,479 | 49,027 | 49,104 | 49,104 | 15.42% | 15.60% | 15.60% | 15.13% |
| WECC-NWPP | 40,630 | 39,405 | 45,804 | 46,407 | 46,407 | 16.24% | 17.77% | 17.77% | 15.67% |
| WECC-RMRG | 10,346 | 9,899 | 12,003 | 12,383 | 12,383 | 21.25% | 25.09% | 25.09% | 14.70% |
| WECC-SRSG | 29,402 | 28,890 | 35,208 | 35,388 | 35,388 | 21.87% | 22.49% | 22.49% | 13.50% |
| **TOTAL-UNITED STATES** | **757,880** | **725,251** | **916,131** | **923,938** | **953,687** | **26.32%** | **27.40%** | **31.50%** | **15.00%** |
| | | | | | | | | | |
| MRO-Manitoba Hydro | 3,143 | 3,143 | 4,296 | 4,516 | 4,641 | 36.68% | 43.68% | 47.66% | 12.00% |
| MRO-SaskPower | 3,044 | 2,953 | 3,665 | 3,665 | 3,904 | 24.13% | 24.13% | 32.22% | 13.00% |
| NPCC-Maritimes | 3,182 | 3,182 | 4,860 | 4,860 | 4,860 | 52.73% | 52.73% | 52.73% | 15.00% |
| NPCC-Ontario (IESO) | 22,533 | 22,533 | 30,101 | 31,271 | 36,735 | 33.59% | 38.78% | 63.03% | 20.40% |
| NPCC-Québec | 20,988 | 20,988 | 32,582 | 32,356 | 32,356 | 55.24% | 54.16% | 54.16% | 10.00% |
| WECC-NWPP | 17,631 | 17,619 | 23,657 | 23,737 | 23,737 | 34.27% | 34.73% | 34.73% | 12.36% |
| **TOTAL-CANADA** | **70,521** | **70,418** | **99,161** | **100,405** | **106,233** | **40.82%** | **42.59%** | **50.86%** | **10.00%** |
| | | | | | | | | | |
| **TOTAL-MÉXICO** | **2,264** | **2,264** | **2,763** | **2,763** | **2,763** | **22.04%** | **22.04%** | **22.04%** | **11.86%** |
| | | | | | | | | | |
| **TOTAL-NERC** | **830,665** | **797,933** | **1,015,465** | **1,024,517** | **1,060,093** | **27.26%** | **28.40%** | **32.85%** | **15.00%** |
| | | | | | | | | | |
| **EASTERN INTERCONNECTION** | **598,638** | **571,784** | **743,800** | **751,634** | **787,210** | **30.08%** | **31.45%** | **37.68%** | **15.00%** |
| **ERCOT INTERCONNECTION** | **66,076** | **64,605** | **73,211** | **73,334** | **73,334** | **13.32%** | **13.51%** | **13.51%** | **13.75%** |
| **QUÉBEC INTERCONNECTION** | **20,988** | **20,988** | **32,582** | **32,356** | **32,356** | **55.24%** | **54.16%** | **54.16%** | **10.00%** |
| **WESTERN INTERCONNECTION** | **144,963** | **140,556** | **165,873** | **167,192** | **167,192** | **18.01%** | **18.95%** | **18.95%** | **15.00%** |

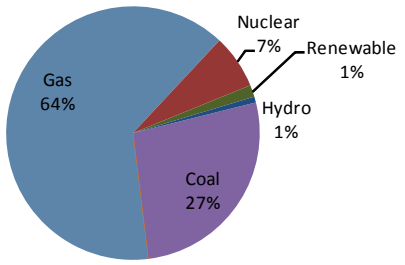
## NERC Assessment Area Reserve Margins for September 2012

| Country / Assessment Area | Demand | | Capacity Resources | | | Planning Reserve Margins | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Total Internal | Net Internal | Existing-Certain & Net Firm | Anticipated | Prospective | Existing-Certain & Net Firm | Anticipated | Prospective | Reference Level |
| | (MW) | (MW) | (MW) | (MW) | (MW) | (%) | (%) | (%) | (%) |
| ERCOT | 56,506 | 55,035 | 73,211 | 73,334 | 73,334 | 33.03% | 33.25% | 33.25% | 13.75% |
| FRCC | 42,303 | 39,194 | 54,986 | 53,552 | 53,608 | 40.29% | 36.63% | 36.78% | 15.00% |
| MISO | 80,453 | 75,924 | 113,165 | 114,865 | 127,332 | 49.05% | 51.29% | 67.71% | 16.70% |
| MRO-MAPP | 4,339 | 4,255 | 5,864 | 6,158 | 6,158 | 37.80% | 44.71% | 44.71% | 15.00% |
| NPCC-New England (ISO-NE) | 23,417 | 22,439 | 30,907 | 31,044 | 34,815 | 37.74% | 38.35% | 55.15% | 15.00% |
| NPCC-New York (NYISO) | 24,715 | 24,715 | 35,293 | 35,293 | 35,293 | 42.80% | 42.80% | 42.80% | 16.00% |
| PJM | 129,163 | 117,516 | 185,641 | 185,641 | 190,471 | 57.97% | 57.97% | 62.08% | 15.60% |
| SERC-E | 39,083 | 37,227 | 50,314 | 51,139 | 53,157 | 35.15% | 37.37% | 42.79% | 15.00% |
| SERC-N | 40,859 | 39,933 | 57,079 | 57,957 | 59,857 | 42.93% | 45.13% | 49.89% | 15.00% |
| SERC-SE | 44,508 | 42,745 | 62,838 | 62,888 | 64,804 | 47.01% | 47.12% | 51.61% | 15.00% |
| SERC-W | 22,083 | 22,072 | 34,591 | 36,569 | 37,443 | 56.72% | 65.68% | 69.64% | 15.00% |
| SPP | 47,189 | 46,264 | 63,508 | 64,552 | 71,531 | 37.28% | 39.53% | 54.62% | 13.60% |
| WECC-CAMX | 46,027 | 43,816 | 50,509 | 50,575 | 50,575 | 15.27% | 15.43% | 15.43% | 15.13% |
| WECC-NWPP | 35,761 | 34,536 | 40,158 | 40,741 | 40,741 | 16.28% | 17.97% | 17.97% | 15.67% |
| WECC-RMRG | 9,205 | 8,758 | 11,370 | 11,750 | 11,750 | 29.83% | 34.17% | 34.17% | 14.70% |
| WECC-SRSG | 26,341 | 25,829 | 33,638 | 33,808 | 33,808 | 30.23% | 30.89% | 30.89% | 13.50% |
| **TOTAL-UNITED STATES** | **671,952** | **640,258** | **903,071** | **909,866** | **944,678** | **41.05%** | **42.11%** | **47.55%** | **15.00%** |
| | | | | | | | | | |
| MRO-Manitoba Hydro | 2,918 | 2,918 | 3,960 | 4,180 | 4,305 | 35.71% | 43.25% | 47.53% | 12.00% |
| MRO-SaskPower | 3,044 | 2,953 | 3,457 | 3,457 | 3,938 | 17.09% | 17.09% | 33.37% | 13.00% |
| NPCC-Maritimes | 3,392 | 3,392 | 4,821 | 4,821 | 4,821 | 42.13% | 42.13% | 42.13% | 15.00% |
| NPCC-Ontario (IESO) | 20,954 | 20,954 | 27,428 | 28,605 | 36,735 | 30.90% | 36.51% | 75.31% | 20.40% |
| NPCC-Québec | 20,829 | 20,829 | 32,808 | 32,582 | 32,582 | 57.51% | 56.43% | 56.43% | 10.00% |
| WECC-NWPP | 16,732 | 16,720 | 23,580 | 23,662 | 23,662 | 41.03% | 41.52% | 41.52% | 12.36% |
| **TOTAL-CANADA** | **67,869** | **67,766** | **96,054** | **97,307** | **106,042** | **41.74%** | **43.59%** | **56.48%** | **10.00%** |
| | | | | | | | | | |
| **TOTAL-MÉXICO** | **2,214** | **2,214** | **2,704** | **2,704** | **2,704** | **22.15%** | **22.15%** | **22.15%** | **11.86%** |
| | | | | | | | | | |
| **TOTAL-NERC** | **742,035** | **710,238** | **999,480** | **1,007,520** | **1,051,067** | **40.72%** | **41.86%** | **47.99%** | **15.00%** |
| | | | | | | | | | |
| **EASTERN INTERCONNECTION** | **528,420** | **502,501** | **733,852** | **740,721** | **784,268** | **46.04%** | **47.41%** | **56.07%** | **15.00%** |
| **ERCOT INTERCONNECTION** | **56,506** | **55,035** | **73,211** | **73,334** | **73,334** | **33.03%** | **33.25%** | **33.25%** | **13.75%** |
| **QUÉBEC INTERCONNECTION** | **20,829** | **20,829** | **32,808** | **32,582** | **32,582** | **57.51%** | **56.43%** | **56.43%** | **10.00%** |
| **WESTERN INTERCONNECTION** | **136,280** | **131,873** | **159,609** | **160,884** | **160,884** | **21.03%** | **22.00%** | **22.00%** | **15.00%** |

# ERCOT

| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 72,947 | - |
| Future-Planned | 123 | - |
| Supply-Side Demand Response | 0 | - |
| Net Capacity Transactions | 264 | - |
| **Anticipated** | **73,334** | **13.51%** |
| Existing-Other and Future-Other | 0 | - |
| **Prospective** | **73,334** | **13.51%** |
| **Reference Margin Level** | - | **13.75%** |

On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **63,531** | **64,605** |
| Demand-Side Demand Response (2012) | - | 1,471 |
| Supply-Side Demand Response (2011) | 1,433 | - |
| **Total Internal** | **64,964** | **66,076** |

| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 63,531 | 1.69% |
| Actual Peak Demand | 68,416 | -5.57% |
| All-Time Summer Peak Demand (August 3, 2011) | 68,416 | -5.57% |

Assessment Area Boundary



*Note: Additional information regarding the methods and assumptions used in the development of the ERCOT seasonal assessment can be found in Appendix I and on the NERC website.*[36]

## Assessment Area Highlights

The ERCOT Region is an electric interconnection located entirely in the state of Texas that operates as a single Balancing Authority and Reliability Coordinator. The Anticipated Reserve Margin is expected to fall below the Reference Margin in August of the 2012 summer. Insufficient reserves during peak hours could result in emergency operating conditions, including the possibility of curtailing interruptible loads and even rotating outages of Firm loads. In order to minimize this risk, ERCOT is working with the Public Utility Commission of Texas (PUCT) and market participants to ensure that all potential resources, including the possible recall of mothballed units and increased demand response programs, are made available during the 2012 summer.

A total of 1,597 MW of on-peak capacity additions and units returning to service prior to the 2012 summer season, which includes 688 MW of mothballed units recalled by the collective efforts of the PUCT, market participants, and ERCOT. Capacity additions and units returning to service consist of 1260 MW of gas generation, 275 MW of coal, 35 MW of wind (with a nameplate capacity of 402 MW), and 27 MW of solar. According to the ERCOT demand forecast, Total Internal Demand is expected to decrease from the actual 2011 system peak of 68,416 MW to the forecasted 2012 peak of 66,195 MW.[37] This equates to a growth rate of -3.2 percent. The growth rate from last summer's forecasted peak load (64,964 MW), compared to this summer's forecasted peak load (66,195 MW) is based on the (50/50) average weather conditions is 1.9 percent.

[36] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

[37] Developed using average weather conditions and referred to as the "50/50" forecast.

According to currently available information, water availability is not expected to have a significant impact on generation output this summer season, even in the event that drought conditions as severe as last summer persist. No significant transmission constraints are expected to impact reliability during the upcoming summer season. Continued load growth throughout the planning horizon will require continued assessment and planning of new transmission assets in order to ensure reliable delivery of electricity to consumers.

## Planning Reserve Margins

The Existing-Certain and Net Firm Transactions Reserve Margin is projected to be 13.3 percent, which is below the 13.75 percent Reference Margin for ERCOT. The Anticipated and Prospective Reserve Margins for the 2012 summer assessment period are both projected to be 13.5 percent, also below the ERCOT's Reference Margin. The ERCOT Reference Margin (referred to as the Planning Reserve Margin in ERCOT documentation) of 13.75 percent is established through a Loss-of-Load Events (LOLEv) analysis of no more than 0.1 events per year based on an updated probabilistic study completed in 2010.[38] **Error! Not a valid bookmark self-reference.** includes the 2011 and 2012 Reserve Margins for the ERCOT Assessment Area.

**Table 1: ERCOT Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 13.75% | 13.75% |
| Existing-Certain & Net Firm Transactions | 13.86% | 13.32% |
| Anticipated | 14.26% | 13.51% |
| Prospective | 14.26% | 13.51% |

The Anticipated Reserve Margin for 2012, 13.5 percent, is lower than the 16.9 percent and 14.3 percent Anticipated Reserve Margin that was projected in NERC's *2011 Long-Term Reliability Assessment* and *2011 Summer Reliability Assessment,* respectively. The extreme hot and dry conditions experienced in ERCOT during the summer of 2011 (the hottest summer on record for any state) upwardly adjusted the calculated expectation of average weather conditions (derived from the past sixteen years of weather data). This adjustment, in expectation for average weather, has elevated the expected load forecast for 2012 (an increase of approximately 1.2 percent). Although the 2012 (and beyond) forecast has been adjusted upwards, the 2012 forecast peak demand is actually less than the 2011 actual peak demand.

The use of an extreme temperature assumption (90/10 scenario) produces a 2012 demand forecast of 67,492 MW,[39] or 2 percent higher than the average (50/50) weather profile. Using the 90/10 forecast for the 2012 summer season would produce a decrease in the reserve margins to the following levels: Existing-Certain and Net Firm Transactions: 8.5 percent; Anticipated: 8.7 percent; Prospective: 8.7 percent.

A 925 MW thermal plant that was originally scheduled to be available for the 2012 summer has been delayed and is not expected to be available until March 2013. Overall, the development of other

[38] http://www.ercot.com/content/meetings/board/keydocs/2010/1116/Item_07_-_2010_Loss_of_Load_Events_(LOLEV),_Target_Reserve_M.zip

[39] The 90/10 scenario was applied in the *Seasonal Assessment of Resource Adequacy for the ERCOT Region – Summer 2012*. (http://www.ercot.com/content/news/presentations/2012/SARA-Summer2012_V5.pdf).

capacity has lagged behind load growth in the ERCOT Region. ERCOT is currently working with the PUCT and market participants to ensure that all potential resources are made available during the 2012 summer season. ERCOT is actively pursuing market rule changes that will expand the number of resources that can participate in the Emergency Interruptible Load Service (EILS) program.[40,41] ERCOT is working with Transmission Service Providers (TSP) to better coordinate activation of load resources included in the TSP demand-response programs. Finally, ERCOT and the PUCT are evaluating options to increase availability of other potential generation and demand-side resources.[42]

ERCOT is conducting a study to better understand current market dynamics and to assess obstacles that are delaying or preventing resource development. ERCOT has an energy-only market design, requiring developers of new generation to base expectations for revenue, primarily on their expectation of long-term, locational market prices. Delays in generation development are potentially a result of a combination of low market prices (due to low natural gas prices and significant wind generation development); reduced availability of capital for financing; and the general uncertainty associated with changing environmental regulations.

One of the largest near-term risks to resource adequacy in ERCOT is the legal action associated with the Cross-State Air Pollution Rule (CSAPR). In the event that the rule is reinstated during the 2012 summer season following legal review, resource owners in ERCOT may revert to their previously announced compliance plans, which in aggregate would result in a further reduction in available generation of approximately 1,200 to 1,400 MW. This would reduce both the Anticipated and Prospective Reserve Margins to 11.3 percent and would reduce the Existing-Certain and Net Firm Capacity Reserve Margin to 11.2 percent.

## Demand

The 2011 summer actual peak demand set a new record for the ERCOT Region on August 3, 2011 of 68,416 MW. This peak demand was higher than the projected 2011 summer peak of 64,964 MW, due to extreme, above-normal temperatures in August. The summer of 2011 was noted as being the hottest summer on record of any state by the National Oceanographic and Atmospheric Administration (NOAA).[43] Ambient temperatures, particularly in the load centers that have experienced population growth, including Dallas/Ft. Worth, San Antonio and Houston, have been primary drivers of ERCOT's peak loads. Table 2 includes the demand forecasts for the 2011 and 2012 summers for the ERCOT Assessment Area.

**Table 2: ERCOT Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| **Net Internal** | **63,531** | **64,605** | **1,074** | **1.69%** |
| **Total Internal** | **64,964** | **66,076** | **1,112** | **1.71%** |

[40] http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/39948_31_721501.PDF

[41] Program to be renamed "Emergency Response Service (ERS)," effective June 1, 2012.

[42] http://www.ercot.com/mktrules/issues/nprr/426-450/450/index; and http://www.ercot.com/mktrules/issues/nprr/451-475/451/index

[43] http://www.noaanews.noaa.gov/stories2011/20110908_auguststats.html

ERCOT is also analyzing the impacts of localized incremental load-growth due to shale gas development near Ft. Worth and south of San Antonio. Transmission service providers are informing ERCOT of shale gas developments resulting in incremental additional loads, ranging upwards to 120 MW in several counties.

The demand forecast developed by ERCOT is based on economic and weather indicators and historical regional loads. The projected peak demand forecast for 2012 is 66,195 MW, an increase of 1.9 percent from the summer 2011 projected peak demand of 64,964 MW. The 2012 forecast is based on revised average (50/50) weather conditions, the calculation of which now includes extreme conditions experienced in 2011. A projected 90/10 peak demand forecast for 2012 is 67,492 MW which would not result in a new record system peak. There have been no significant changes in the forecasting process since the last summer's assessment.

## Demand-Side Management

Load Resources (LRs)[44] providing Responsive Reserve Service,[45] an ancillary service provides averages of approximately 886 MW of dispatchable, contractually committed demand-side Load as a Capacity Resource during summer peak hours.[46] This set of loads is the only demand-side resource providing ancillary services to the ERCOT grid.

ERCOT's Emergency Interruptible Load Service (EILS), which is designed to be deployed in the late stages of a grid emergency, prior to shedding involuntary Firm load, represents demand-side Contractually Interruptible Demand. This service is being renamed the Emergency Response Service (ERS). Based on average EILS commitments during 2011, approximately 585 MW is expected to be available during the 2012 summer peak. These programs would reduce summer peak demand by a little over 2 percent.[47] Figure 20 and Table 3 present the demand response forecasted for the 2011 and 2012 summer peaks in the ERCOT Assessment Area.

[44] See Section 3.17 and 3.18 of http://www.ercot.com/content/mktrules/nprotocols/current/03-030112_Nodal.doc; Previously referred to as Load Acting as Resources (LaaRs).

[45] Based on the most recently available data: http://www.ercot.com/content/mktrules/nprotocols/current/02-020111_Nodal.doc.

[46] The limit on LRs participation is in the process of being revised due to the increased overall procurement of responsive reserves. See http://www.ercot.com/content/mktrules/issues/nprr/426-450/434/keydocs/434NPRR-12_Board_Report_022112.doc for more information.

[47] Measurement and verification procedures for these programs are defined in the Performance Monitoring section of the ERCOT Protocols. http://www.ercot.com/content/mktrules/nprotocols/current/08-020111_Nodal.doc

**Figure 20: ERCOT Demand Response**

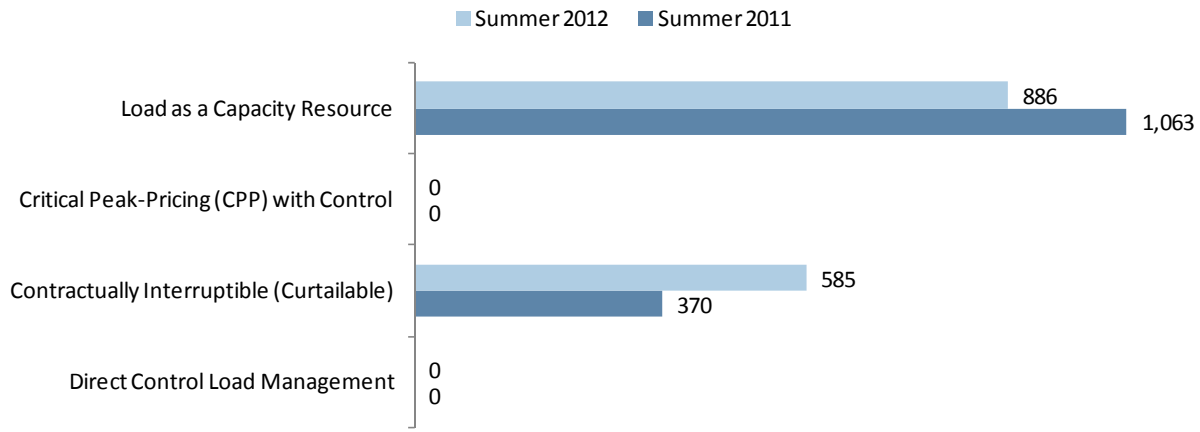



**Table 3: ERCOT Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 0 | 0 | 0 |
| Contractually Interruptible (Curtailable) | 370 | 585 | 0 |
| Critical Peak-Pricing (CPP) with Control | 0 | 0 | 0 |
| Load as a Capacity Resource | 1,063 | 886 | 0 |
| **Total Demand Response** | **1,433** | **1,471** | **0** |
| **Percentage of Total Internal Demand** | **2.21%** | **2.23%** | **0.00%** |

In addition to these two demand response programs, several Transmission Service Providers (TSP) have individual contractual arrangements with loads that can respond to instructions to reduce total energy usage.

As stated before, ERCOT is actively pursuing market rule changes that will expand the number of resources that can participate in the newly formed ERS program, which will replace the current EILS program. ERCOT estimates that this change will increase the resources participating in the current EILS program by 130 to 200 MW. Additionally, ERCOT is working to better coordinate activation of load resources included in the TSP demand-response programs.

Utility savings, as measured and verified by an independent contractor, have exceeded utility goals.[48] In the latest assessment, these programs implemented after the restructuring of electric utilities in Texas have produced 1,666 MW of peak demand reduction and 4,110 GWh of electricity savings between 1999 and 2010.[49] This demand reduction is accounted for within the load forecast and only the expected incremental portion for the coming year, 119 MW, is included as a demand adjustment for the summer season.

[48] http://www.texasefficiency.com/report.html
[49] http://www.texasefficiency.com/files/EUMMOT_EEIP_June_2011.pdf.

## Generation

Existing-Certain capacity in ERCOT, as reported by the generation owners, is 72,947 MW. The primary fuel sources for generation in ERCOT include natural gas (40,776 MW) and coal (17,071 MW). Since the prior season, 1,597 MW of on-peak generation capacity has been added or will return to service, consisting of 1,260 MW of gas generation (which includes 688 MW of mothballed units recalled into service), 275 MW of coal generation, 35 MW of wind generation (with nameplate capacity of 402 MW), and 27 MW of solar generation. Table 4 includes ERCOT forecasts for available resources during the 2011 and 2012 summer. Table 4 includes projections of ERCOT resources for the 2011 and 2012 summer.

**Table 4: ERCOT Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 72,255 | 72,947 |
| Future-Planned | 260 | 123 |
| Supply-Side Demand Response | 1,433 | 0 |
| Net Capacity Transactions | 281 | 264 |
| **Anticipated** | **74,229** | **73,334** |
| Existing-Other and Future-Other | 0 | 0 |
| **Prospective** | **74,229** | **73,334** |

One 925 MW thermal generation project was expected to become available prior to the 2012 summer season. However, this project has been delayed, and is not expected to be available until March 2013.

Of the Existing-Certain capacity, 117 MW is biomass and 43 MW is solar. An expected 105 MW of biomass generation is included as Future-Planned resources. ERCOT counts these resources as available on-peak. There are 544 MW of hydro generation capacity in ERCOT; none of this capacity is considered expected on-peak. Of the 9,829 MW of existing wind generation capacity and 206 MW of Future-Planned wind generation capacity (expected on-line by June 2012), only 855 MW of Existing and 18 MW of Future-Planned is included in the expected On-Peak Resources respectively (the currently approved Effective Load Carrying Capability [ELCC] of wind resources in ERCOT is 8.7 percent).[50] A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 21 and Table 5.

[50] 2012 numbers are based on current filings: http://www.texasefficiency.com/files/EUMMOT_EEIP_June_2011.pdf.

**Figure 21: ERCOT Renewable Generation**

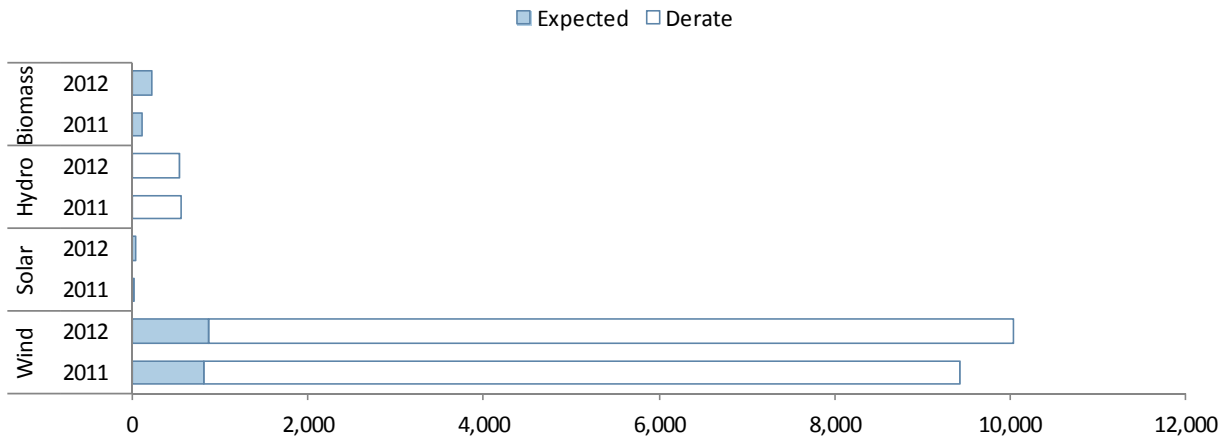



**Table 5: ERCOT Renewable Generation**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 820 | 873 | 15 | 43 | 0 | 0 | 106 | 222 |
| Derate | 8,607 | 9,162 | 0 | 0 | 563 | 544 | 0 | 0 |
| **Nameplate** | **9,427** | **10,035** | **15** | **43** | **563** | **544** | **106** | **222** |

ERCOT has substantial experience maintaining operational reliability with significant and increasing levels of interconnected variable generation. Total available variable generation during the 2012 summer is not expected to be much higher than the output available during the 2011 summer. Using a combination of state-of-the-art wind generation forecasts, and flexible levels of ancillary services, ERCOT will effectively manage available wind and solar generation to support system reliability using current procedures. Continuing development of wind resources along the coast, which exhibit generation patterns that are more correlated with summer peak loads than wind sited in inland western portions of Texas, is also expected to increase the overall reliability benefit from wind generation. An evaluation of possible differences in a locational-based wind ELCC is in progress.

With only 43 MW of solar resources on the ERCOT transmission system, it is expected that the variability of these resources will not adversely affect the reliability of the grid. If solar generation becomes more prevalent in ERCOT, it will become necessary to develop an estimate of the ELCC of solar resources and a process for forecasting solar resources.

Less than 1 percent of the ERCOT generation capacity is hydro. These facilities are typically operated as run-of-river or planned release due to downstream needs and not operated specifically to produce electricity. As a result, limited availability of hydro generation should not have a reliability impact on the ERCOT Region this summer, even if drought conditions persist.

There are 1,946 MW of existing capacity that is mothballed (indefinitely idled) and considered inoperable (Existing-Inoperable). This capacity is not counted toward reserves during the 2012 summer season. Of this capacity, only 154 MW could return to service in 60 days or less. Since the last summer season, 1,131 MW of gas generation and 138 MW of petroleum coke fueled generation have returned to service, and 279 MW of additional gas generation has been put into mothballed (Existing-Inoperable) status. There is no Existing-Other generation in ERCOT.

No significant change is expected in the availability of behind-the-meter (or distributed) generation for the 2012 summer season. There are 2,962 MW of "switchable" generation that can operate in the ERCOT system or in the adjacent (not synchronously interconnected) regions. ERCOT counts all of this generation capacity as available, except for 317 MW, which is obligated to serve load outside of the ERCOT region.

Scheduled outages are expected for 240 MW of capacity during the month of August. Historically, there are approximately 710 MWs of scheduled outages and 3,080 MWs of forced outages (unplanned outages).[51] After the summer high load period, approximately 5,000 MW of scheduled outages for maintenance usually begin in September.

## Capacity Transactions

The ERCOT Region is a separate Interconnection with only asynchronous ties to Southwest Power Pool (SPP) and Mexico's Comision Federal de Electricidad (CFE). As such, ERCOT does not share reserves with other Regions. There are two asynchronous ties between ERCOT and SPP with a total of 820 MW of transfer capability and three asynchronous ties between ERCOT and Mexico with a total of 280 MW of transfer capability. One of these ties (35 MW) between ERCOT and CFE is on an extended maintenance outage and is not scheduled to be available during the summer 2012 season. On-peak capacity transactions projected for the 2012 summer are included in Table 6.

**Table 6: ERCOT Capacity Transactions**

| Capacity Transactions | Imports | Exports | Net |
|---|---|---|---|
| Firm | 581 | 317 | 264 |
| Expected | 0 | 0 | 0 |
| **Total** | **581** | **317** | **264** |

The ERCOT Region does not rely on external resources to meet demand under normal operating conditions; however, under emergency support agreements, it may request external resources for emergency services over the asynchronous ties or by block transfer of discrete loads. For the summer 2012 season, ERCOT has 458 MW of imports from SPP and 123 MW from CFE. Of the total SPP imports, 48 MW are tied to a long-term contract for a purchase of Firm load from specific generation. The remaining imports of 410 MW from SPP and 123 MW from CFE represent one-half of the asynchronous tie transfer capability, included to reflect emergency support arrangements.[52] Several SPP members own 317 MW of a power plant located in the ERCOT Region, resulting in a Firm export of that amount from ERCOT to SPP. There are no known non-Firm contracts (signed, pending, etc.) that are known to be under negotiation or study.

## Transmission

Several significant transmission improvements,[53] listed below, have been, or are expected to be completed throughout the ERCOT Region to meet reliability needs or reduce market congestion prior to,

[51] Per preliminary summer assessment located at: http://www.ercot.com/content/news/presentations/2012/SARA%20-%20Preliminary%20Summer%202012.pdf.

[52] This capacity is reduced from previous seasonal assessments due to the extended outage of the 35 MW Eagle Pass tie between ERCOT and CFE.

[53] As of March 2012.

or during the 2012 summer season.[54] Overall, 358 circuit miles of new 345 kV transmission have been added, with 15 additional circuit miles of upgrades. Additionally, 9 miles of 138 kV transmission have been added, with 260 circuit miles of upgrades.

Several significant system improvements associated with the transmission plan developed to serve the Competitive Renewable Energy Zones (CREZ) are scheduled to be in service by the 2012 summer season.[55] These projects are listed below:

- 345 kV double circuit from Bowman to Riley [85 circuit miles];
- 345 kV double-circuit from Sweetwater East to Central Bluff to Bluff Creek [91 circuit miles];
- 345 kV single-circuit from Twin Butte to Big Hill [31 circuit miles];
- 345 kV single circuit from Riley to Oklaunion [3.5 circuit miles];
- 345 kV double-circuit from Dermott Switch to Scurry County South [65 circuit miles].
- 345 kV double-circuit from Bell County East to TNP One [83 circuit miles];
- 345 kV switching station at Bell County East;
- 345/138 kV autotransformers constituting 4,500 MVA are scheduled to be installed at the Southeast Nacogdoches, Anna Switch, P. H. Robinson, Lewisville, Central Bluff, and Zenith substations

No delays are currently expected in meeting in-service dates of transmission projects needed for reliability. Some transmission outages may be scheduled during the 2012 summer season, but these outages are not expected to impact reliability. ERCOT performs outage coordination to maintain reliability for any planned transmission outages. As transmission constraints are identified, plans are developed to provide for preemptive or planned responses to maintain reliability.

Recent 345/138-kV autotransformer failures at the Venus Switch, Gilleland Creek and Salem substations are not expected to have an adverse impact on system reliability over the 2012 summer season. ERCOT is reviewing options with the affected transmission service providers to replace the autotransformers with spares, if available. The reason for these recent, non-related autotransformer failures is being evaluated at this time.

A voltage stability screening analysis to assess reactive power needs on the ERCOT system for the 2012 summer will be completed before the start of the summer season. Response of the network to NERC Category A, B and selected C contingencies will be reviewed and if necessary, actions planned will be provided.

## Operations

For the 2012 summer season, no significant special operating studies have been conducted for the ERCOT Region and no unusual operating conditions that could impact reliability are anticipated. A voltage stability screening analysis to assess reactive power needs on the ERCOT system for the upcoming summer will be completed prior to the start of the season. Response of the network to NERC Category A, B and selected C contingencies test will be documented.

[54] Additional details on transmission projects can be found in the "Report on Existing and Potential Electric System Constraints and Needs" located on the following website: http://www.ercot.com/content/news/presentations/2012/2011%20Constraints%20and%20Needs%20Report.pdf.

[55] http://www.texascrezprojects.com/default.aspx.

For variable resources, ERCOT will use established operational procedures during the 2012 summer season. ERCOT has implemented a wind power forecasting system to allow ERCOT Independent System Operators (ISO) to identify and take appropriate action when wind resource schedules may not track expected changes in wind output. ERCOT has also implemented a wind ramp forecasting tool that provides a probabilistic assessment of the magnitude and likelihood of a significant change in aggregate wind output over upcoming operating periods. In addition, ERCOT evaluates the impact of increased installed wind generation on ancillary services requirements on an ongoing basis.[56]

Resources are expected to be tight for 2012 summer season and beyond. ERCOT and the PUCT are evaluating all potential generation and demand-side resources in order to minimize the potential for Firm load loss during emergency conditions. It is expected that emergency conditions, including Energy Emergency Alerts (EEA), will occur during the 2012 summer season. Recently 688 MWs of mothballed generation signaled a return to service prior to the start of the summer season. Barring a repeat of extreme heat conditions similar to those encountered during the 2011 summer, elevated levels of unit outages and other issues noted in the Vulnerability Assessment section below, there should be sufficient reserves to avoid the need for rotating outages to maintain system reliability.

ERCOT regularly monitors the availability of surface water resources for cooling at generation facilities. Recent analyses indicate that it is unlikely that there will be any impact to resource availability over the upcoming 2012 summer season due to drought conditions. The effects of any limitations that arise will be mitigated through the procurement of ancillary services, including Reliability Unit Commitment (RUC)[57] deployments, or emergency procedures, if required. At this time, these issues do not constitute a significant reliability concern for the Region.

There are no anticipated reliability concerns for the summer season resulting from over generation during low demand at current levels of wind generation and overall resource mix.

Currently, ERCOT limits the participation of dispatchable, contractually committed Demand-Side Load as a Capacity Resource (referred to as Load Resources in ERCOT Region). This limitation allows up to 50 percent (1,150 MW limit) of the Responsive Reserve (RRS) Ancillary Service,[58] which can be deployed in response to large frequency excursions (below 59.7 Hz) or during system emergencies. There are approved changes to the ERCOT Protocols, increasing RRS by 500 MW, which may impact the Load Resource participation. ERCOT is performing a technical review of the RRS change with regards to the Load Resource impact.[59] ERCOT procures these Load Resources across all hours to address system conditions at all times – not just during peak periods. ERCOT's monitoring and testing programs ensure that these Load Resources will perform when called. The status of Load Resources providing Ancillary Services is monitored in real–time, via 2-second telemetry.

ERCOT procures Emergency Interruptible Load Service (EILS) (referred to by NERC as Demand-Side Contractually Interruptible Demand). These resources are monitored by using after-the-fact metering and are subject to payment reductions and suspension from the program for failing to meet availability

[56] http://www.ercot.com/content/mktinfo/dam/kd/ERCOT%20Methodologies%20for%20Determining%20Ancillary%20Service%20Requir.zip.
[57] http://www.ercot.com/content/mktrules/nprotocols/current/02-020111_Nodal.doc.
[58] http://www.ercot.com/content/mktrules/nprotocols/current/02-020111_Nodal.doc.
[59] http://www.ercot.com/mktrules/issues/nprr/426-450/434/index.

requirements. Both Load Resources and EILS products are subject to annual unannounced load-shed testing, to be followed by an additional test if the first is unsuccessful. A second consecutive unsuccessful test subjects the resource to suspension.

There are no restrictions on the number of deployments in a day for Load Resources procured in the day-ahead Ancillary Services market. EILS Loads are procured for four-month contract periods and are limited to a maximum of eight hours of deployments over those months – with the proviso that the Loads may not return to service until released by ERCOT operations.

Given the recent stay in the implementation of the Cross-State Air Pollution Rule (CSAPR) issued by the D.C Circuit Court of Appeals, no environmental regulations are expected to have an adverse impact on system reliability over the 2012 summer season. Further discussion of the implications of potential Court action is provided in the Vulnerability Assessment.

There are no other anticipated unusual operating conditions that could significantly affect reliability during the 2012 summer season.

## Vulnerability Assessment

The single or combined impacts of the following risk factors could lead to inadequate supply in the ERCOT Region during the 2012 summer: an extremely hot summer resulting in load levels significantly above the forecast; above-normal unit forced outage rates; extended maintenance outages; CSAPR-based idling of units; and financial difficulties of some generation owners creating challenges in obtaining fuel from suppliers.

If such an event occurs, ERCOT will implement actions described in Section 5.6 of the ERCOT Protocols[60] and Section 4 of the ERCOT Operating Guides,[61] which describe EEAs and procedures for use of interruptible load, voltage reductions, procuring emergency energy over the asynchronous ties, and ISO-instructed demand response.

Currently available information indicates that it is unlikely that water unavailability will limit generation resources during the 2012 summer season. No significant increases in variable generation are expected prior to, or during the 2012 summer season; no significant long-term generator outages are expected, and it is unlikely that there will be availability issues associated with demand response programs established in the ERCOT Region.

Gas curtailments do not typically occur in the summer season. Natural gas supply and transportation issues are typically of more concern during the winter season, due to competition with home heating for pipeline and distribution capacity. ERCOT has recently completed an analysis of potential impacts of gas transportation limitations on grid reliability. This study found that any such impacts are unlikely and expected to be minor.[62] Coal transportation issues are not expected to pose a reliability impact in ERCOT this summer. Overall fuel supply issues are not expected to impact 2012 summer resource availability. Finally, no new System Protection Schemes (SPS) or Remedial Action Plans (RAP) has been added since the 2011 summer season.

[60] http://www.ercot.com/mktrules/protocols/current.html.
[61] http://www.ercot.com/mktrules/guides/operating/current.
[62] http://www.ercot.com/content/meetings/board/keydocs/2012/0221/Item_06_-_Gas_Risk_Study.zip.

ERCOT continues to review the potential impacts of changes in environmental regulations on the expected availability of generation resources in the upcoming seasons. Information from the resource owners regarding compliance strategies and unit availability are aggregated to develop compliance scenarios which are then analyzed for impacts to resource adequacy and system reliability using the established ERCOT planning models and processes, as needed. Throughout the past year, ERCOT has reviewed the potential impacts of the several proposed and final environmental rules, including the Mercury and Air Toxics Rule (MATR), and the Cross-State Air Pollution Rule (CSAPR). Reports describing the findings of these studies are available on the ERCOT website.[63] Of the rules and regulations analyzed, only the CSAPR was found to potentially affect generation availability during the 2012 summer season. This rule was stayed by the D.C. District Court of Appeals on December 30, 2011, prior to implementation. Had it not been stayed by the Court, two coal generation units, totaling 1,130 MW, were scheduled to be idled, starting on January 1, 2012, and remain unavailable throughout the 2012 summer season, as a result of compliance requirements of the CSAPR. As a result of the stay imposed by the Court, these plants were not idled and are now expected to be available during the 2012 summer season. The recent amendments to the CSAPR – which, in part, propose an increase to the number of emission allowances allocated to Texas coal units – have unknown impacts on whether or not these two coal plants would be idled if the rule is reinstated, following further review by the Court. As a result of the stay by the Court, it is not expected that extended maintenance outages will be required to install environmental controls to maintain compliance during the 2012 summer season.

Given the expected reserve margin in the ERCOT Region for the 2012 summer season (below the minimum Reference Margin Level), unavailability of one or more large thermal generators due to the compliance requirements of the CSAPR or, in fact, for any reason (such as an extended maintenance outage), would increase the risk of emergency conditions during 2012 summer peak load hours, and could necessitate rotating outages in the event of extreme heat or significant other generation unit outages.

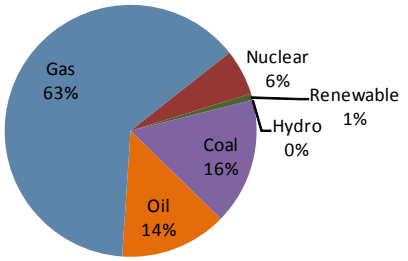
ERCOT is also conducting a study to better understand current market dynamics and to assess obstacles that are delaying or preventing resource development. ERCOT has an energy-only market design, requiring developers of new generation to base revenue expectations primarily on their expectation of long-term, locational market prices. Delays in the development of generation are potentially a result of a combination of low market prices (due to low natural gas prices and significant wind generation development); reduced availability of capital for financing; and uncertainty associated with changing environmental regulations.

[63] http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf; and http://www.ercot.com/content/news/presentations/2011/ERCOT_CSAPR_Study.pdf.

# FRCC

| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 53,096 | - |
| Future-Planned | 0 | - |
| Supply-Side Demand Response | 3,131 | - |
| Net Capacity Transactions | 2209 | - |
| **Anticipated** | **61,115** | **27.84%** |
| Existing-Other and Future-Other | 0 | - |
| **Prospective** | **61,115** | **27.97%** |
| **Reference Margin Level** | 0 | **15.00%** |

On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **42,960** | **42,430** |
| Demand-Side Demand Response (2012) | - | 3,183 |
| Supply-Side Demand Response (2011) | 3,131 | - |
| **Total Internal** | **46,091** | **45,613** |

| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 42,960 | -1.23% |
| Actual Peak Demand | 46,091 | -7.94% |
| All-Time Summer Peak Demand (August 10, 2007) | 46,739 | -9.22% |

Assessment Area Boundary



*Note: Additional information regarding the methods and assumptions used in the development of the FRCC seasonal assessment can be found in Appendix I and on the NERC website.*[64]

## Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the FRCC Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The Reserve Margins for the FRCC Assessment Area are based on Anticipated resources. The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer season.

A net total of 650 MW of capacity will be added during the 2012 summer. According to the FRCC demand forecast, Total Internal Demand has increased from 44,798 MW to 45,613 MW since the 2011 summer. This equates to an annual growth rate of 1.8 percent.

## Planning Reserve Margins

The FRCC is projecting adequate Reserve Margins during the 2012 summer. A 15 percent Reserve Margin criteria[65] is required by the Florida Public Service Commission for the FRCC Region for all planning horizons. Based on the expected load and generation capacity, the calculated Anticipated Capacity Resources Reserve Margin for the summer of 2012 is 27.8 percent when Load Management and Interruptible loads are treated as a demand reduction. Table 7 includes the 2011 and 2012 Reserve Margins for the FRCC Assessment Area.

[64] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

[65] 20 percent for Investor Owned Utilities.

**Table 7: FRCC Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 15.00% | 15.00% |
| Existing-Certain & Net Firm Transactions | 32.60% | 29.59% |
| Anticipated | 32.60% | 27.84% |
| Prospective | 32.60% | 27.97% |

Factors impacting the summer Reserve Margin include a 3 to 4 year period of weak economic demand resulting in more than adequate Reserve Margins. The restrained mobility of relocations to the area has served to reduce forecasted customer growth and projected peak demands over prior forecasts. A rebound in the economy could potentially increase the demand, energy, and load projections that could result in realignment with previous projections.

There exists the possibility that the passage of pending environmental and/or regulatory regulations could lead to timing challenges in the retrofitting and/or building of replacement generation. The forced shutdown of existing generation from these pending activities could cause unscheduled outages of generation, possibly resulting in a decrease in Reserve Margins.

## Demand

Last year's peak demand forecast for the summer of 2011 was 46,091 MW, which was 1,293 MW (2.9 percent) above the 2011 actual demand of 44,798 MW.

The FRCC is forecasted to reach its 2012 summer non-coincident peak Total Internal Demand of 45,613 MW in August, which represents a projected demand increase of 1.8 percent above the actual 2011 summer demand of 44,798 MW. This projection for the 2012 summer is consistent with historical weather-normalized FRCC demand growth and is 1.0 percent lower than last year's summer forecast of 46,091 MW. The small decrease in the 2012 projected summer peak demand is attributed to lower expected consumption and economic activity versus the previous projection. Table 8 includes the 2011 and 2012 Reserve Margins for the FRCC Assessment Area. Table 8 includes the demand forecasts for the 2011 and 2012 summers for the FRCC Assessment Area.

**Table 8: FRCC Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| Net Internal | 42,960 | 42,430 | -530 | -1.23% |
| Total Internal | 46,091 | 45,613 | -478 | -1.04% |

Load growth across individual Load Serving Entities (LSE) in the Region is proportional with the level of load growth seen across the FRCC Assessment Area.

## Demand-Side Management

The 2012 summer Net Internal Demand forecast includes the effects of 3,183 MW of potential demand reductions from the use of load management (2,563 MW) and interruptible demand (620 MW). Demand response within FRCC is treated as a "demand reduction" and not as a capacity resource. Demand reduction is used primarily to shave the peak demand. Figure 22 and Table 9 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the FRCC Assessment Area.

**Figure 22: FRCC Demand Response**

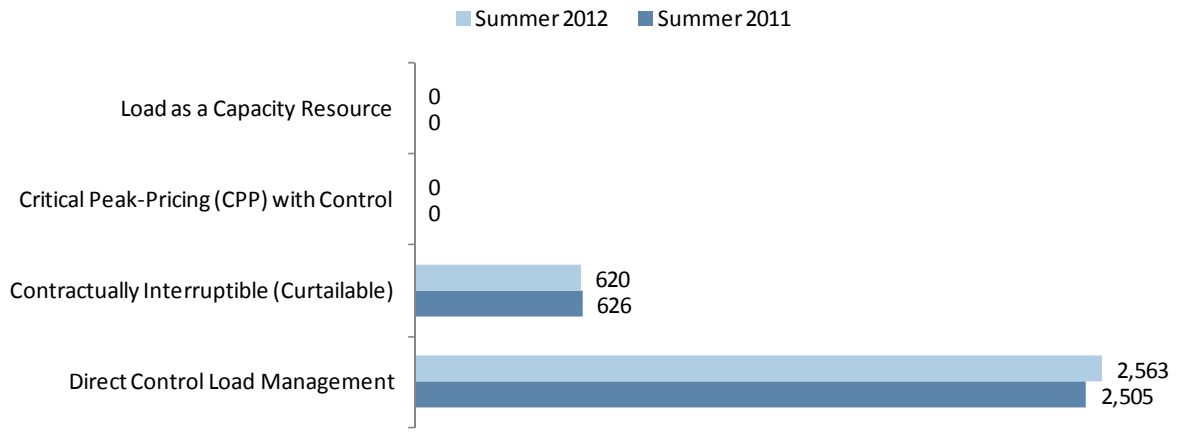



**Table 9: FRCC Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 2,505 | 2,563 | 0 |
| Contractually Interruptible (Curtailable) | 626 | 620 | 0 |
| Critical Peak-Pricing (CPP) with Control | 0 | 0 | 0 |
| Load as a Capacity Resource | 0 | 0 | 0 |
| **Total Demand Response** | **3,131** | **3,183** | **0** |
| **Percentage of Total Internal Demand** | **6.79%** | **6.98%** | **0.00%** |

There are a variety of Energy Efficiency programs implemented by entities throughout the FRCC Region. These programs can include commercial and residential audits (surveys) with incentives for duct testing and repair, high efficiency appliances (air conditioning, water heater, heat pumps, refrigeration, etc.), general rebates, and rebates for high efficiency lighting.

The Florida Public Service Commission approved updated, more aggressive numeric Demand-Side Management (DSM) goals in 2010 for participating entities in the state, of which some have begun implementation. Financial incentives have also been made available to various utilities with DSM achievements that exceed Commission-approved goals. It is projected that over the coming decade, Demand Response will increase at an average annual growth rate of about 1.5 percent.

## Generation

The FRCC Region counts on 53,096 MW of Existing-Certain resources, of which 44 MW are hydro and 334 MW are Biomass. Potential solar capacity is projected to be 55 MW; however most of this capacity is de-rated with approximately 7.8 MW considered as a Firm resource, available during peak demand, with the remainder being used as an energy-only resource. Derated hydro capacity will be 11 MW, while Existing-Other merchant plant capability of 183.4 MW is potentially available as future resources of FRCC members and others. There are a total of 2,821 MW of Existing-Inoperable resources for the 2012 summer. Table 10 includes projections of FRCC resources for the 2011 and 2012 summer.

**Table 10: FRCC Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 55,775 | 53,096 |
| Future-Planned | 0 | -745 |
| Supply-Side Demand Response | 3,131 | 0 |
| Net Capacity Transactions | 2,209 | 1,890 |
| **Anticipated** | **61,115** | **54,241** |
| Existing-Other and Future-Other | 0 | 56 |
| **Prospective** | **61,115** | **54,297** |

There are no retirements planned for the upcoming season, however, 1,780 MW of generation is being temporarily reactivated from Inactive Reserves[66] to function as replacement capacity for 1,652 MW of generation planned for capacity upgrades prior to the summer season. A net projected capacity of 881 MW will be added prior to the beginning of the summer season, with 745 MW being temporarily removed during August for other planned unit upgrades. These activities are not expected to have an impact on generation scheduled to serve load. There are 849 MW of capacity not included in the summer forecast due to a long-term outage; however, this capacity is scheduled to be returned to service in late 2014. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 23 and Table 11.

**Figure 23: FRCC Renewable Generation**

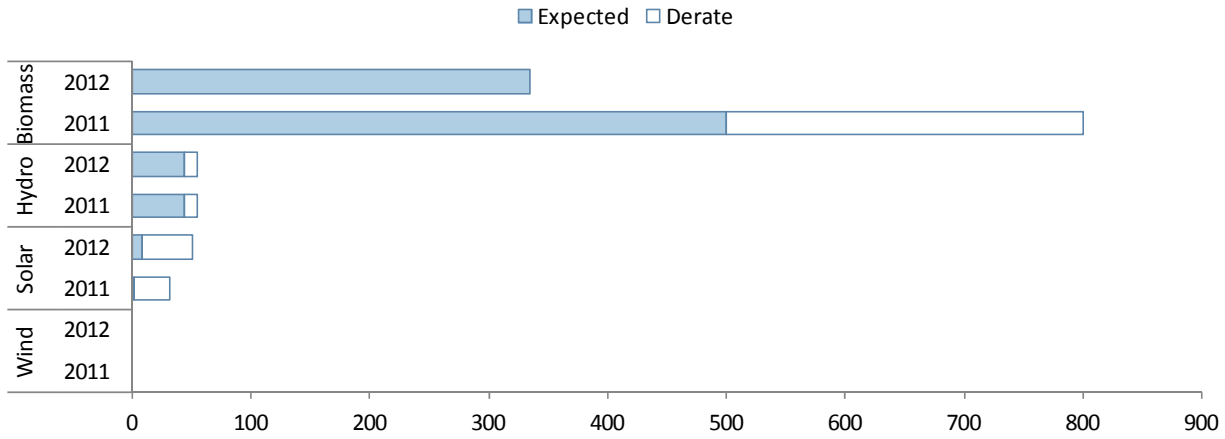



**Table 11 FRCC Renewable Generation**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 0 | 0 | 1 | 8 | 44 | 44 | 500 | 334 |
| Derate | 0 | 0 | 30 | 44 | 11 | 11 | 300 | 0 |
| **Nameplate** | **0** | **0** | **31** | **51** | **55** | **55** | **800** | **334** |

[66] IEEE 762: Inactive Reserves – "the state in which a unit is unavailable for service but can be brought back into service after some repairs in a relatively short duration of time." FRCC does include Inactive Reserves capacity in the calculation of Reserve Margins when this generation is not in commercial service.

## Capacity Transactions

There are 1,197 MW of generation under Firm contract, available to be imported into the Region from the SERC-SE Assessment Area throughout the summer season, and another 836 MW of member-owned generation, which is dynamically dispatched out of the SERC-SE Assessment Area. These purchases have Firm transmission service to ensure deliverability into the FRCC Region.

The FRCC Region has 143 MW of generation under Firm contract to be exported during the summer into the SERC-SE Assessment Area through 2020. These sales have Firm transmission service to ensure deliverability. On-peak capacity transactions projected for the 2012 summer are included in Table 12.

**Table 12: FRCC Capacity Transactions**

| Capacity Transactions | Imports | Exports | Net |
|---|---|---|---|
| Firm | 2,033 | 143 | 1,890 |
| Expected | 0 | 0 | 0 |
| **Total** | **2,033** | **143** | **1,890** |

Non-Firm resources or Expected transactions are not included in the assessment for the calculation of reserve margins. The FRCC Region does not rely on external resources for emergency imports and reserve sharing. However, there are emergency power contracts in place between SERC members and FRCC entities.

## Transmission

Currently the FRCC Region expects to have three Bulk Electric System (BES) transmission facilities staggered out of service during the 2012 summer season. These outages were studied as part of the FRCC Operational Seasonal Study and are not anticipated to affect reliability. Additionally, no concerns were identified for meeting the target in-service dates of new projects that may impact system reliability during the 2012 summer season.

The FRCC Region has not identified any specific projects that are needed to maintain or enhance reliability during the 2012 summer season. Additions to the FRCC Bulk Power System are primarily related to expansion in order to serve forecasted growing demand and maintain the reliability of the Bulk Power System in the longer-term planning horizon.

## Operations

FRCC expects the BES to perform adequately over various system operating conditions with the ability to deliver the resources to meet the load requirements at the time of the summer peak demand. The FRCC performed a Summer Transmission Assessment and Operational Seasonal Study to assess the adequacy and robustness of the FRCC BES under expected 2012 summer peak load and under anticipated system conditions (taking into account generation and transmission maintenance activities). This regional assessment and operational study analyzed the performance of the transmission system under normal conditions, single contingency events, and selected multiple contingency events determined relevant by pass studies. The results were coordinated and peer-reviewed by the FRCC's Operations Planning Working Group to ensure the BES performs adequately throughout the summer timeframe. The study results demonstrated that potential thermal and voltage conditions exceeding the applicable screening criteria could be successfully mitigated under normal conditions, single contingency events, and selected multiple contingency events. The transmission system within the FRCC Region is expected to perform reliably for the anticipated 2012 summer peak season system operating conditions.

No new operating procedures are needed as result of integration of variable resources for the summer 2012. Minimum demand and over generation scenarios typically do not occur under normal conditions due to limited variable resources within the FRCC Region.

Demand-Side Management load control programs within the FRCC are treated as "demand reduction" and not as a capacity resource. Based on past experience, demand reduction is used on a limited basis and is expected to be fully available when called upon. The FRCC does not anticipate any issues with the availability of demand reduction during the 2012 summer season.

Based on the FRCC Summer Transmission Assessment and Operational Seasonal Study, no unusual operating conditions are expected to impact reliability for the upcoming 2012 summer.

## Vulnerability Assessment

Three 800 MW class units are scheduled to be unavailable during some period of the 2012 summer season (one continuous, others will be staggered). Based on the FRCC Summer Transmission Assessment and Operational Seasonal Study, the unavailability of these units is not anticipated to cause any reliability concerns. The FRCC does not foresee any issues associated with long-term (extended) drought conditions, the unavailability of demand resources or as a result of increase in variable generation.

Following the 2011 summer season, two new permanent Special Protection Systems (SPS) were installed within the FRCC Region. The SPSs were designed to protect BES facilities under certain generation dispatch scenarios and specific multiple contingency events.

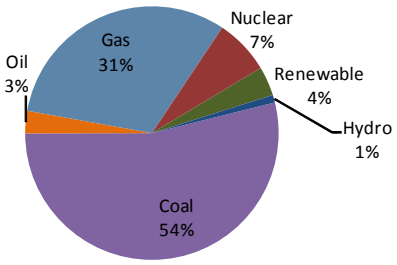
The FRCC Region is not anticipating any reliability impacts as result of environmental and/or regulatory restrictions for the summer of 2012. The Environmental Protection Agency (EPA) did issue the Cross State Air Pollution Rule (CSAPR) on August 8, 2011. This rule would require the FRCC region to reduce NOx emissions by 30 percent of 2010 levels during the Ozone season from May 1 through September 30, starting in the summer of 2012. However, a large number of parties have petitioned for judicial review and a stay of the CSAPR. On December 30, 2011 the D.C. Circuit Court of Appeals did issue a stay of the CSAPR until all the challenges to the rule are resolved. The Florida Electric Coordinating Group's (FCG) Environmental sub-committee is not anticipating CSAPR to take effect prior to 2013.

For the 2012 summer season, no concerns are anticipated due to a limited fuel supply within the FRCC Region. There is no fuel availability or supply issues identified at this time. Based on recent studies, current fuel diversity, alternate fuel capability and fuel study results, the FRCC does not anticipate any fuel transportation issues affecting resource capability during the 2012 summer season.

# MISO

| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 107,107 | - |
| Future-Planned | 120 | - |
| Supply-Side Demand Response | 3,523 | - |
| Net Capacity Transactions | 1,655 | - |
| **Anticipated** | **113,952** | **28.65%** |
| Existing-Other and Future-Other | 13,347 | - |
| **Prospective** | **127,299** | **43.72%** |
| **Reference Margin Level** | - | **16.70%** |

On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **91,753** | **88,573** |
| Demand-Side Demand Response (2012) | - | 4,529 |
| Supply-Side Demand Response (2011) | 7,819 | - |
| **Total Internal** | **99,572** | **93,102** |

| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 91,753 | -3.47% |
| Actual Peak Demand | 96,755 | -8.46% |
| All-Time Summer Peak Demand (July 31, 2006) | 109,157 | -18.86% |

Assessment Area Boundary



*Note: Additional information regarding the methods and assumptions used in the development of the MISO seasonal assessment can be found in Appendix I and on the NERC website.*[67]

## Assessment Area Highlights

MISO's membership has changed since the 2011 summer. Duke Energy Ohio and Duke Energy Kentucky consolidated into the PJM RTO on January 1, 2012, removing approximately 5,700 MW of load and generation from MISO's footprint. Currently, MISO's membership consists of 40 Transmission Owners and 98 non-transmission owners. MISO's scope of operations encompasses 49,641 miles of transmission over 11 states and one Canadian province. MISO's Energy and Operating Reserves market includes 363 market participants serving over 38.9 million people.

MISO continues to establish reserve margin requirements for its members. For planning year 2012 MISO's System Installed Generation Planning Reserve Margin (PRMSYSIGEN) requirement on a MISO coincident load basis is 16.7 percent. The PRMSYSIGEN for the MISO Assessment Area is based on Net Internal Demand and Anticipated Capacity Resources. The Anticipated Reserve Margin exceeds MISO's Reserve Margin Requirement during 2012 summer season.[68]

In addition to the existing capacity of 121,994 MW for the expected peak month of July 2012, a total of 350 MW of nameplate wind capacity is anticipated to be added between the 2012 summer months of August and September. According to the MISO's demand forecast for July 2012, Total Internal Demand has decreased from 96,755 MW[69] to 93,103 MW since the 2011 summer. However, the actual Total

[67] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

[68] Forecasts in this report reflect MISO load and resources which are not included in MAPP's Assessment Area.

[69] Actual Integrated Peak Load of 103,621 MW (July 20th hour-ending 17:00) decreased approximately 5.5 percent due to Duke's exit and approximately an additional 1.0 percent due to load shared between MISO and MAPP Planning Coordinator boundaries.

Internal Demand for the 2011 summer was a 90/10 load. For an equivalent comparison, with a 90/10 2012 summer load forecast, Total Internal Demand has actually increased from 96,755 MW to 98,377 MW. This equates to an annual summer growth rate of 1.7 percent.

## Planning Reserve Margins

For planning year 2012 MISO's System Installed Generation Planning Reserve Margin (PRMSYSIGEN) requirement on a MISO coincident load basis is 16.7 percent.[70]

For the summer of 2012 the Anticipated and Prospective Reserve Margins are 28.7 percent and 43.7 percent, respectively, both exceeding MISO's Reference Margin Level. Some contributing factors to adequate reserve margin levels through the 2012 summer are provided. Table 13 includes the 2011 and 2012 reserve margins for the MISO Assessment Area.

**Table 13: MISO Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 15.00% | 16.70% |
| Existing-Certain & Net Firm Transactions | 20.62% | 26.77% |
| Anticipated | 20.62% | 28.65% |
| Prospective | 33.99% | 43.72% |

A regional benefit of MISO is that the respective members do not experience peak during the same period. This estimated diversity of the MISO Assessment Area is 4.61 percent of MISO's Unrestricted Non-Coincident Peak Load. For more information on how MISO calculates Load Diversity, please see the 2012 LOLE study report. MISO's estimated diversity contributes 6.2 percentage points to the Anticipated Reserve Margin.

MISO Market Participants are forecasted to offer 4,529 MW of Demand-Side programs (Interruptible Load, IL and Direct Control Load Management, DCLM) in the market to serve MISO load, contributing 5.5 percentage points to the Anticipated Reserve Margin.

MISO Market Participants are forecasted to offer 3,523 MW of Supply-Side Load as a Capacity Resource, served by behind-the-meter generation, in the market to serve MISO load, contributing 3.7 percentage points to the Anticipated Reserve Margin.

Due to MISO's substantial generation resource fleet, MISO's Existing-Certain Capacity Resources expected to be available during the 2012 summer season's peak exceed even those resources procured through MISO's Module E process to meet the 16.7 percent reserve margin requirement. This excess capacity amounts to 6,333 MW, contributing 6.5 percentage points to the Anticipated Reserve Margin.

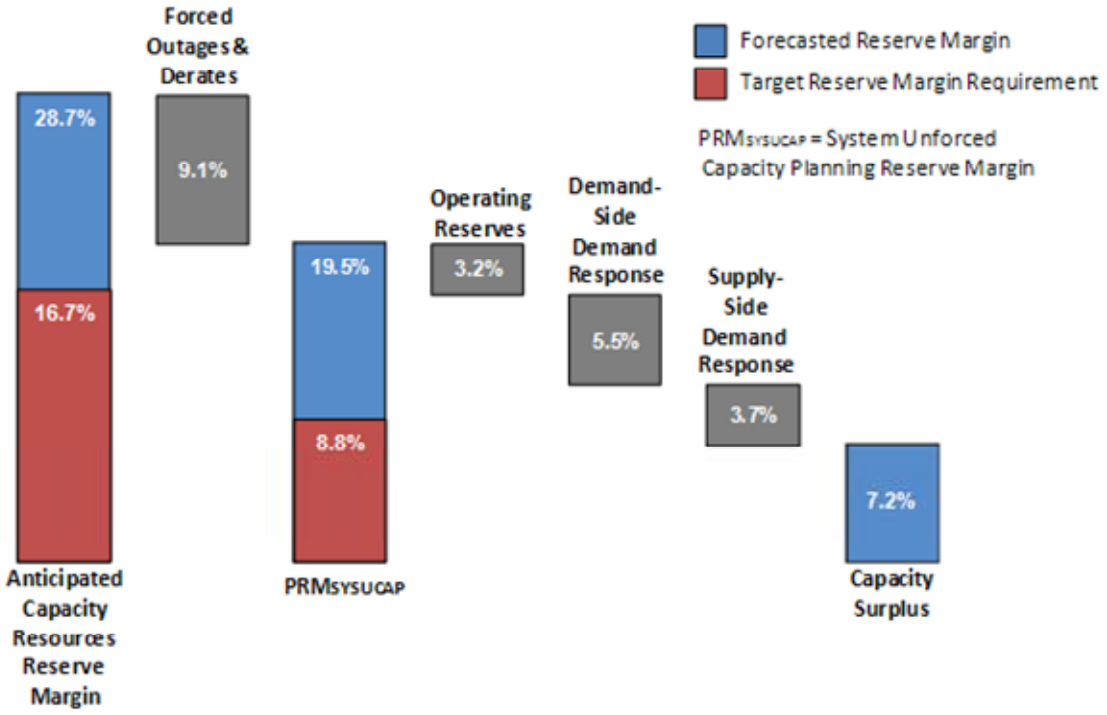
Entities outside of MISO are forecasted to offer 3,073 MW of external capacity in the market to serve MISO load. In addition to these Firm Full-Responsibility Purchases, through Module E, MISO expects 1,934 MW of additional Non-Firm imports. Net Capacity Transactions are expected to amount to 3,202 MW during the 2012 summer peak, contributing 3.3 percentage points to the Anticipated Reserve Margin.

[70] For more information regarding how MISO establishes requirements please see the 2012 LOLE study report: https://www.midwestiso.org/Library/Repository/Study/LOLE/2012%20LOLE%20Study%20Report.pdf.

In addition to the reserve margins discussed in previous paragraphs, MISO calculates a System Unforced Capacity Planning Reserve Margin (PRMSYSUCAP ) which takes into account MISO's forced outage rate and Planning Reserves prior to Emergency Operating Procedures (EOPs) that anticipates the reserve level under normal operating conditions during the 2012 summer.[71]

To forecast forced outages and derates, MISO applies each unit's 5 year average Equivalent Forced Outage Rate on Demand (EFORd), from Generator Availability Data System (GADS), to their respective summer ratings. Under normal operating conditions, MISO Demand Response (Demand-Side IL, Demand-Side DCLM, Supply-Side Load as a Capacity Resource, BTMG) are inaccessible to the operators. MISO must initiate a level 2 Maximum Generation Emergency Event to access Demand Response. Also, MISO's Operating Reserves of approximately 2,400 MW are only utilized given a level 3 Event. The waterfall chart below, Figure 24, shows the progression of reserve levels from Anticipated Reserve Margin to Planning Reserves prior to EOPs.

**Figure 24: MISO 2012 Forecasted Summer Peak Reserve Margin Criteria**




It is always possible that a combination of high loads due to adverse weather, a lack of wind generation, high rate of outage, lack of external support, lack of Demand Response, etc could result in curtailment of Firm load. Such a curtailment is considered to be a low probability event for this summer, since the projected reserve margin far exceeds the established minimum requirement, external support and demand response have Firm contracts to serve MISO load this summer through the Module E process, and fuel scarcity is not projected to be an issue. For further risk analysis, please refer to Operations and Vulnerability Assessment sections 8 and 9 respectively of this report.

[71] Normal operating conditions refers to MISO's operation of the grid without initiating Emergency Operating Procedures. This margin is calculated for the 2012 summer season by removing 10,052 MW of EOPs, which are a component of the PRMSYSUCAP.

## Demand

During the 2011 summer season, MISO experienced an instantaneous peak load[72] of 103,975 MW and settled peak of 103,621 MW on July 20, 2011 (hour ending 17:00 EST). For consistency with other reporting entities, adjusting last year's settled load for the Duke Energy Ohio and Kentucky (DEOK) departure and for load in the MAPP Assessment Area, as an adjacent Planning Coordinator to MISO, the settled load of 96,755 MW is being used for the purposes of this analysis. Table 14 includes the demand forecasts for the 2011 and 2012 summers for the MISO Assessment Area.

**Table 14: MISO Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| Net Internal | 91,753 | 88,573 | -3,180 | -3.47% |
| Total Internal | 99,572 | 93,102 | -6,470 | -6.50% |

Demand values, as reported by Network Customers, are weather-normalized (50/50, forecasts). An unrestricted non-coincident peak demand is created on a regional basis by summing the coincident monthly forecasts for the individual Load Serving Entities (LSE) in the larger regional area of interest. In MISO's Module E construct, the final Module E forecast is due by June 1, 2012. To capture the uncertainty around final and initial Module E forecast that is used in assessment reports, MISO calculated the difference between 2011 initial and final Module E forecast and prorated MISO's Total Internal Demand forecast to capture this uncertainty. This is a new enhancement to MISO's forecasting technique for the 2012 summer season. Similar to last summer, a load diversity factor was calculated by observing the individual peaks of each Local Balancing Authority (BA) and comparing these values against the system peak. This produced an estimated diversity of 4,500MW.

According to the MISO demand forecast for the peak month of July 2012, Total Internal Demand has decreased from 96,755 MW to 93,103 MW, compared to the 2011 summer. However, the actual Total Internal Demand for the 2011 summer was comparable to a 90/10 load, based on last summer's 50/50 forecasts. For an equivalent comparison, with a 90/10 scenario applied to the 2012 summer load forecast, Total Internal Demand has actually increased from 96,755 MW to 98,377 MW. This equates to an annual summer growth rate of 1.7 percent.

## Demand-Side Management

MISO bases its resource evaluation on the actual market peak. MISO currently separates Demand-Side Demand Resources into two categories: Interruptible Load (IL) and Direct Controlled Load Management (DCLM). IL of 3,506 MW for this assessment is the magnitude of customer demand (usually industrial) that – in accordance with contractual arrangements – can be interrupted at the time of peak by direct control of the system operator (remote tripping), or by action of the customer, at the direct request of the system operator. DCLM of 1,023 MW (one percent of Total Internal Demand) for this assessment is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. DCLM is typically used for "peak shaving." The Resource Adequacy processes as set forth in Module E of MISO's tariff acts as the measurement and

[72] The instantaneous load is the highest value metered during the peak hour, while the settled load is the integrated average value of metered data over the peak hour.

verification tool for Demand Response. Figure 25 and Table 15 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the MISO Assessment Area.

**Figure 25: MISO Demand Response**

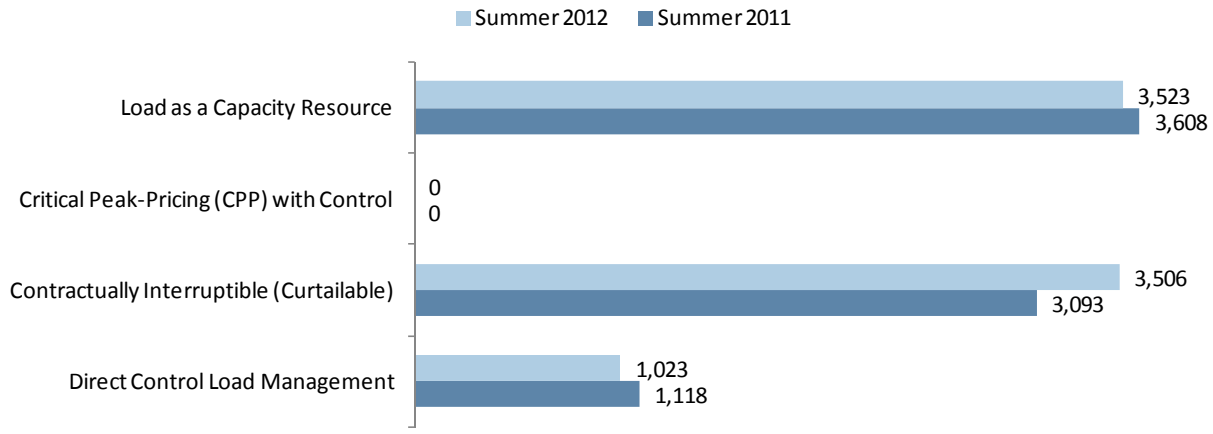



**Table 15: MISO Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 1,118 | 1,023 | 0 |
| Contractually Interruptible (Curtailable) | 3,093 | 3,506 | 0 |
| Critical Peak-Pricing (CPP) with Control | 0 | 0 | 0 |
| Load as a Capacity Resource | 3,608 | 0 | 3,523 |
| **Total Demand Response** | **7,819** | **4,529** | **3,523** |
| **Percentage of Total Internal Demand** | **7.85%** | **4.86%** | **3.78%** |

## Generation

MISO's projected Existing-Certain, Existing-Other, and Existing-Inoperable capacities are 107,107 MW, 13,347 MW, and 1,540 MW respectively, totaling 124,994 MW of Existing Capacity Resources projected to be available for the forecasted peak month of July 2012. The three primary fuel sources for MISO are coal, gas and nuclear. Coal units will account for 56.1 percent, while gas and nuclear Units will be 23.2 percent, and 7.9 percent respectively. Since last summer season, 9 new wind resources have come online with a total nameplate rating of 691 MW, of which, 102 MW is considered Existing-Certain for the 2012 summer season.

MISO anticipates 120 MW of Future-Planned resources consisting of facility upgrades to bring an additional 82MW on line from an existing coal facility and an additional 32MW from a new coal generator to be added leading up to the 2012 summer and 210 MW of Future-Planned resources consisting of interconnection of wind capacity to be added during the 2012 summer season. Table 16 includes projections of MISO resources for the 2011 and 2012 summer.

**Table 16: MISO Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 107,391 | 107,107 |
| Future-Planned | 0 | 120 |
| Supply-Side Demand Response | 7,819 | 3,523 |
| Net Capacity Transactions | 4,894 | 1,655 |
| **Anticipated** | **120,104** | **113,952** |
| Existing-Other and Future-Other | 13,309 | 13,347 |
| **Prospective** | **133,413** | **127,299** |

The largest negative impact to MISO's Existing capacity since the prior season was due to the departure of DEOK from MISO, effective January 2012. This directly reduced MISO's Existing-Certain capacity by 5,070 MW.

In addition to the 107,107 MW of Existing-Certain capacity, MISO plans to use BTMG under Firm contract through Module E to serve MISO load this summer. MISO projects 3,523 MW of BTMG as Supply-Side Demand Response to be available during the 2012 summer season. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 26 and Table 17.

**Figure 26: MISO Renewable Generation**

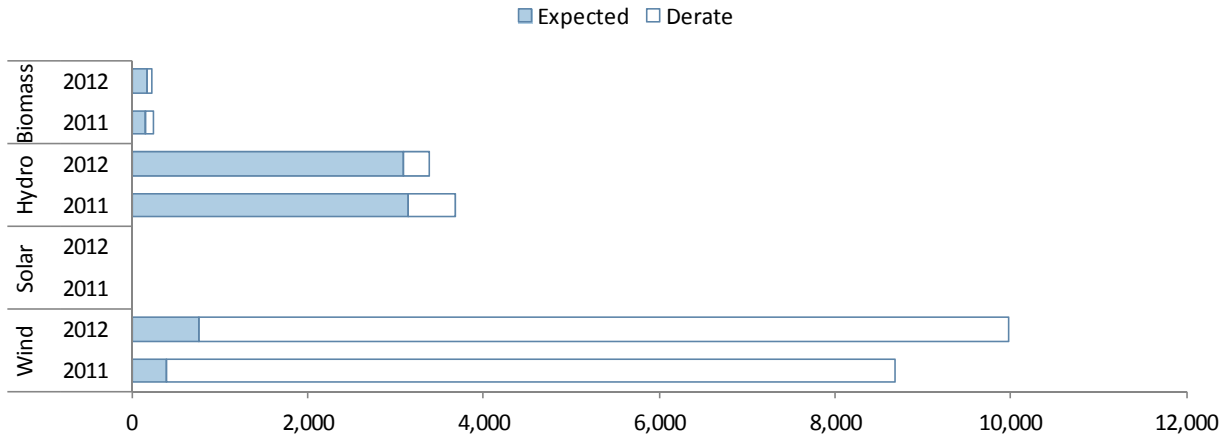



**Table 17: MISO Renewable Generation**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 382 | 765 | 0 | 0 | 3,144 | 3,088 | 148 | 173 |
| Derate | 8,290 | 9,204 | 0 | 0 | 524 | 302 | 96 | 50 |
| **Nameplate** | **8,672** | **9,969** | **0** | **0** | **3,668** | **3,390** | **244** | **223** |

Currently, 10,791 MW of wind resources are registered with MISO; however, MISO applies a 14.7 percent wind capacity credit to MISO wind resources based on their historical performance. The 14.7 percent system wide MISO wind capacity credit is based on determining the Effective Load Carrying Capacity (ELCC) of the intermittent wind resources. For more detailed information regarding the wind capacity credit and ELCC study please see the 2012 LOLE study report. Applying the 14.7 percent capacity credit brings the wind capacity down from 10,791 MW to 1,586 MW; however, MISO is not

expecting 1,586 MW on peak. Of the 1,586 MW of wind, only 765 MW are registered as designated network resources in March 2012 commercial model, and are expected to serve MISO load during the 2012 summer season. Therefore, of the 10,791 MW of registered wind resources, MISO anticipates 765 MW of wind capacity on peak during the 2012 summer.

## Capacity Transactions

Sellers of generation external to MISO submit generation obligations (MW) through the Module E process for each planning month. Currently, 3,081 MW of Firm imports are obligated for the peak month of 2012 summer. Currently, under the MISO Module E construct, obligations do not go beyond the planning month.

Table 18 includes the capacity transaction values for 2012 Summer Peak. Historically, these values have been determined by the Eastern Interconnection Reliability Assessment Group (ERAG). Import values into the MRO have been provided as in the past. In future assessments, these values should be reported on a sub-regional basis. In the below values, the MRO base case flow is 3,201 MW of net imports (Expected and Firm).

**Table 18: MISO Capacity Transactions**

| Capacity Transactions | Imports | Exports | Net |
|---|---|---|---|
| Firm | 3,081 | 1,426 | 1,655 |
| Expected | 1,933 | 387 | 1,546 |
| **Total** | **5,014** | **1,813** | **3,201** |

## Transmission

Several transmission projects are expected to be completed by the end of the summer season to enable reliable and efficient transmission service for the MISO region. These include 112 miles of new lines, line upgrades and re-builds. Among these projects are four 230 kV lines in Duke Energy Midwest (DEM), Montana Dakota Utilities (MDU), American Transmission Corporation (ATC) and Ottertail Power (OTP), respectively, and one 345 kV line in ATC. Also, expected to be in service are one new bulk power transformer and two transformer upgrades in areas of MDU, Ameren Illinois and ATC. MISO does not anticipate any existing, significant transmission lines or transformers being out of service through the summer season. MISO does not have any transmission constraints that could significantly impact reliability. Interregional transmission transfers are not available at this time.

## Operations

MISO has not performed any special operating studies to determine the impacts of adverse conditions for the 2012 summer season; however, MISO is evaluating the impact of potential low water level issues across the MISO footprint due to a drier than average 2011-2012 winter season and other scenarios that would detract from projected reserve levels. This analysis is documented in the Vulnerability Assessment section of this report. Additionally, MISO is conducting a Summer Readiness Workshop, consistent with prior years, where stakeholder collaboration helps maximize preparedness for the summer season. This workshop includes an assessment of our resources and the expected Planning Reserve Margin, given a forecasted peak load, an assessment of the transmission system under stressed conditions, and a review of key Emergency Operating Procedures (EOP) to ensure familiarity with steps and expectations.

While MISO has not implemented any new EOPs associated with variable resources over the last year, the registration of Dispatchable Intermittent Resource (DIR) continues to increase the availability of dispatchable wind in the MISO BA. As of March 1, 2012, nearly 40 percent of MISO wind resources have registered and operate as a DIR. Another 40 percent will be required to register and operate as a DIR by March 1, 2013.

MISO does not anticipate any reliability concerns as a result of minimum demand and over generation during the 2012 summer period. MISO has a Supply Surplus procedure that contains steps for managing such conditions to mitigate potential impacts on reliability. In addition, the launch of DIR on June 1st, 2011 has resulted in more timely elimination of minimum generation conditions as these resources can now be dispatched down and may set a very low Locational Marginal Price (LMP), incenting other generation to offer more flexibility to be reduced as well. MISO also reviews forecasted system conditions a few days in advance of any expected minimum generation conditions and communicates the impending situation to MISO stakeholders to allow participants a chance to schedule generation maintenance during these times.

During times of peak conditions or when MISO otherwise forecasts the potential for maximum generation conditions, we survey Local Balancing Authorities to obtain the amount of their demand response resources that would be available under a given notification time (2 hours for example). If we reach the point of needing to call on these resources, we deploy only the amount needed, and expect that all will perform. The use of these resources is part of the progression through our Capacity Emergency procedure. If some demand response resources do not perform there are other resources available to us in the subsequent steps of the procedure that we would consider engaging if necessary.

The number of times that a demand response resource could be deployed during any period would be restricted by the type of resource and its offer parameters. For a DRR Type II, the combination of its Minimum Run Time and Minimum Down Time once deployed would restrict the resource's availability for deployment during the remainder of the period. Similarly, for a DRR Type I, the combination of its Minimum Interruption, Minimum Duration and Minimum Non-Interruption Interval would do the same.

MISO could see an impact to its generation fleet from the abnormally dry conditions that persist in some areas within our Footprint. According to the National Oceanic and Atmospheric Administration (NOAA), the 2011-2012 winter season was drier than average across the entire United States. This limited snowfall for many locations. Snow cover had the 3$^{rd}$ smallest footprint in the 46 years it has been measured. This contributed to areas of moderate to severe drought in the Upper Midwest and Northern Plains, which could impact the availability of water, used to cool generating facilities in these areas. MISO is currently collaborating with stakeholders to assess the potential magnitude of this issue.

MISO does not foresee significant impacts to reliability during the 2012 summer season that would result from regulatory restrictions. However, MISO does anticipate that the recently finalized and/or developing EPA regulations will impact MISO in the future. Specifically, the recent delay of the implementation of the Cross-State Air Pollution Rule (CSAPR) has delayed impacts beyond the 2012 summer season. MISO continues to work, both internally and in collaboration with stakeholders, to maximize preparedness efforts for the impacts of CSAPR and other potential regulations. This includes conducting ongoing studies to determine the amount of generation maintenance that could be scheduled in a given season, assuming a reduced capacity level directly due to regulation.

*NERC's Recommendation to Industry: Considerations of Actual Field Conditions in Determination of Facility Ratings*[73] is currently in its implementation phase. While the assessment results may lead to derates of transmission lines or outages during the coming season, coordination between the Transmission Owners, Transmission Operators, and Reliability Coordinators have helped alleviate reliability concerns. Advanced notice of impending derates allows for coordination efforts to take place, such that even a sudden derate or outage is treated like a forced outage and reliability procedures and processes address the situation. MISO does not anticipate any other unusual operating conditions for the 2012 summer season.

## Vulnerability Assessment

MISO may experience low water level issues, similar to what was experienced during the 2006 summer season, across the MISO footprint due to a drier than average 2011-2012 winter season. MISO compared the EFORd from 2006 to MISO's 5 year average EFORd, and it was determined that the 5 year average rate captures the impact of low water issues. Therefore, MISO does not anticipate the forecasted reserve levels to deteriorate due to drought conditions during the 2012 summer months.

MISO does not have reliability concerns for the upcoming summer due to long-term generator outages, unresponsive demand response, or increases in variable generation. MISO has not identified any Special Protection Systems (SPS) or Remedial Action Schemes (RAS) that have been installed since last summer.

MISO does not expect environmental regulations to have an impact during the upcoming summer season; however, MISO is currently studying potential resource adequacy impacts due to pending environmental regulations that could come into impact subsequent seasons. Specifically, MISO is continuing to evaluate four proposed EPA regulations: Cooling Water Intake Structures (CWIS), Coal Combustion Residuals (CCR), Cross State Air Pollution Rule (CSAPR), and Mercury and Air Toxics Standards (MATS). The CSAPR ruling has been stayed by the courts; however, MISO is evaluating the impact of this rule for planning year 2013 and beyond. One potential impact of CSAPR is increased maintenance outages during off-peak months. MISO is currently conducting studies to determine the amount of allowable maintenance which may be taken out in a given month while still maintaining annual system reliability at or better than a Loss of Load Expectation (LOLE) of 1 day in 10 years.

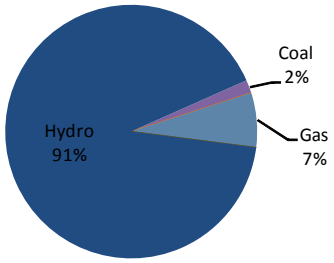
At this time MISO does not know of any generators that will be out of service during the 2012 summer season for installation of environmental controls. It is the responsibility of MISO's Market Participants to ensure fuel supplies are adequate. At this time, MISO membership has not voiced concern about inadequate fuel supply for the upcoming summer season.

[73] http://www.nerc.com/filez/facility_ratings_alert.html.

# MRO-Manitoba Hydro

| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 5,353 | - |
| Future-Planned | 11 | - |
| Supply-Side Demand Response | 227 | - |
| Net Capacity Transactions | -1110 | - |
| **Anticipated** | **4,481** | **43.68%** |
| Existing-Other and Future-Other | 0 | - |
| **Prospective** | **4,481** | **47.66%** |
| **Reference Margin Level** | - | **12.00%** |

On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **3,166** | **3,143** |
| Demand-Side Demand Response (2012) | - | 0 |
| Supply-Side Demand Response (2011) | 0 | - |
| **Total Internal** | **3,166** | **3,143** |

| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 3,166 | -0.73% |
| Actual Peak Demand | 3,378 | -6.96% |
| All-Time Summer Peak Demand (July 25, 2007) | 3,422 | -8.15% |

Assessment Area Boundary



*Note: Additional information regarding the methods and assumptions used in the development of the MRO-Manitoba Hydro seasonal assessment can be found in Appendix I and on the NERC website.*[74]

## Assessment Area Highlights

The Reserve Margins for the Manitoba Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain above the Reference Margin Level throughout the 2012 summer season.

A total of 220 MW of capacity additions will be added during the 2012 summer. According to the Manitoba demand forecast, Total Internal Demand has decreased from 3,166 MW to 3,143 MW since the 2011 summer. This equates to an annual growth rate of -.73 percent.

## Planning Reserve Margins

Manitoba is projecting adequate Planning Reserve Margins during the 2012 summer, with all three categories expected to exceed 27.0 percent throughout. As a Region with predominately hydro resources, Manitoba has both an energy criterion and a capacity reserve margin criterion. The capacity reserve margin criterion, which is considered as the NERC-termed Reference Margin Level, requires a minimum of 12 percent reserve, above the forecasted peak demand. This criterion is more stringent, compared to the 10 percent level assigned to predominately hydro systems that do not submit a Reference Margin Level. Table 19 includes the 2011 and 2012 reserve margins for the MRO-Manitoba Assessment Area.

[74] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

**Table 19: MRO-Manitoba Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 12.00% | 12.00% |
| Existing-Certain & Net Firm Transactions | 41.19% | 36.68% |
| Anticipated | 41.54% | 43.68% |
| Prospective | 41.54% | 47.66% |

Manitoba Hydro has planned and maintained its system in accordance with good utility practice, such that adequate Planning Reserve Margins shall be maintained throughout the summer season. No unit retirements, extraordinary load growth or additional environmental restrictions are expected to impact reliability. Manitoba Hydro does not anticipate any significant challenges to maintaining assessment projections throughout the 2012 summer season.

## Demand

As seen in Table 20, the actual peak demand in summer 2011 was 3,378 MW. The peak demand for summer 2011 was forecast to be 3,166 MW. Last summer was warmer than normal and the peak demands occurred at higher temperatures than in previous years.

**Table 20: MRO-Manitoba Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| Net Internal | 3,166 | 3,143 | -23 | -0.73% |
| Total Internal | 3,166 | 3,143 | -23 | -0.73% |

The 2011 summer peak forecast for Total Internal Demand was 3,166 MW. The 2012 forecast is 3,143 MW. This amounts to a 1 percent decrease that can be attributed to the enhancement of the hourly load model, which contributed to a small decrease in monthly summer peaks.

## Demand-Side Management

Demand response used for ancillary services (non-spinning reserves) is 50 MW for all months during the summer season. These reserves satisfy a portion of the MISO-Manitoba Hydro Contingency Reserve Sharing Group reserve requirements and are only deployed to help recover from large generation related contingencies on the system.

Manitoba Hydro's Curtailable Rate Program (CRP) is not intended to reduce the peak demand, but rather to meet reliability obligations. Manitoba Hydro will curtail customers in response to system emergencies and to maintain planning and operating reserves. Figure 27 and Table 21 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the MRO-Manitoba Assessment Area.

**Figure 27: MRO-Manitoba Demand Response**

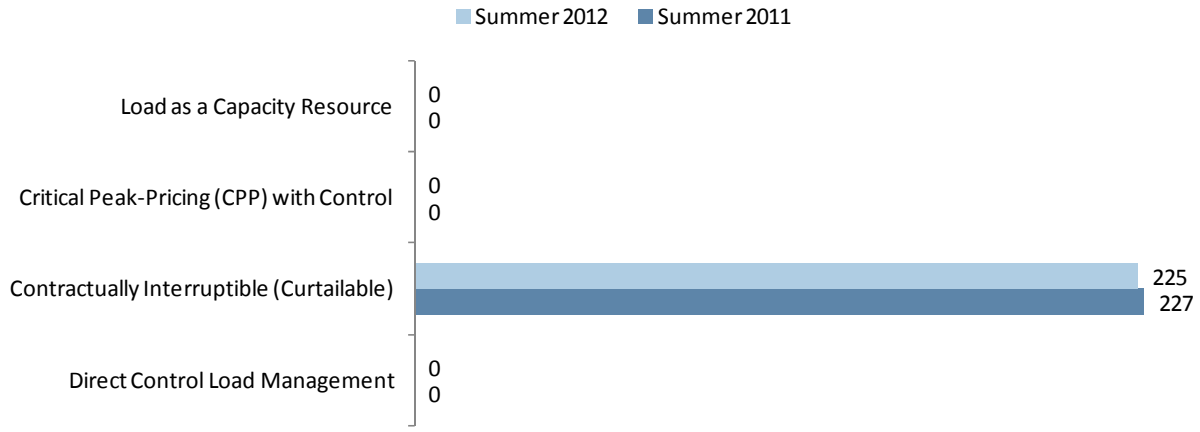



**Table 21: MRO-Manitoba Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 0 | 0 | 0 |
| Contractually Interruptible (Curtailable) | 227 | 0 | 225 |
| Critical Peak-Pricing (CPP) with Control | 0 | 0 | 0 |
| Load as a Capacity Resource | 0 | 0 | 0 |
| **Total Demand Response** | **227** | **0** | **225** |
| **Percentage of Total Internal Demand** | **7.17%** | **0.00%** | **7.16%** |

In Manitoba, new conservation (Energy Efficiency) ranges between 28 MW and 32 MW throughout the summer. Manitoba Hydro's current Power Smart portfolio includes customer service, cost-recovery, incentive-based and rate-based initiatives and programs customized to meet the specific energy needs of the residential, commercial, and industrial markets. This portfolio, consisting of Energy Efficiency, conservation, load management and customer self-generation programs (behind-the-meter generation), is designed to help customers conserve energy, reduce energy costs and protect the environment. Generally, no specific state or regulatory drivers affect demand-side management in Manitoba.

## Generation

For the 2012 summer, 5,151 MW of Existing-Certain, and 125 MW of Existing-Other resources are expected to be available during the peak. There will be no Existing-Inoperable capacity during the 2012 summer. Table 22 includes projections of MRO-Manitoba resources for the 2011 and 2012 summer.

**Table 22: MRO-Manitoba Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 5,353 | 5,151 |
| Future-Planned | 11 | 220 |
| Supply-Side Demand Response | 227 | 225 |
| Net Capacity Transactions | -1,110 | -1,080 |
| **Anticipated** | **4,481** | **4,516** |
| Existing-Other and Future-Other | 0 | 125 |
| **Prospective** | **4,481** | **4,641** |

Manitoba Hydro's primary energy source is through natural water resources. Unit 6 of the Kelsey Generation Station is currently undergoing upgrades scheduled to be completed by May 26, 2012. These upgrades to the unit are expected to add 11 MW of additional Existing-Certain capacity. Additional units at the Wuskwatim Generating Station will be phased in during the 2012 summer. The latest schedule of in-service dates is as follows:

- Unit 1 – June 1, 2012 (74 MW)
- Unit 3 – July 1, 2012 (74 MW),
- Unit 2 August 1, 2012 (74 MW)

These units will provide a total of 208 MW (including aggregate losses when all units are online). Finally, Expansion of the St. Leon Wind Farm is scheduled to be completed by the end of the 2012 summer season and will add an additional 16.5 MW. Manitoba Hydro resource planning does assume an 8 percent capacity factor for wind in the summer assessment period during on-peak hours.

No unit retirements are planned and no project deferments or delays are expected this summer. Various Scheduled Outages this season will range from 120 MW to 529 MW, with 121 MW projected to be out during the peak. Of these outages, approximately 20 MW from the Pointe du Bois Generating Station are expected to remain out of service throughout the summer season. No significant short-term impacts are anticipated due to this ongoing outage.

Manitoba has two existing wind farms: St. Leon and the St. Joseph. St. Leon currently has 104 MW (8 MW on-peak) of nameplate capacity, expected to increase to 120.5 MW (9 MW on-peak) by the end of the 2012 summer. The St. Joseph wind farm maintains a nameplate capacity of 138 MW (11 MW on-peak). Again, the expected on-peak capacity for the summer season equates to 8 percent of the nameplate capacity. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 28 and Table 23.

**Figure 28: MRO-Manitoba Renewable Generation**

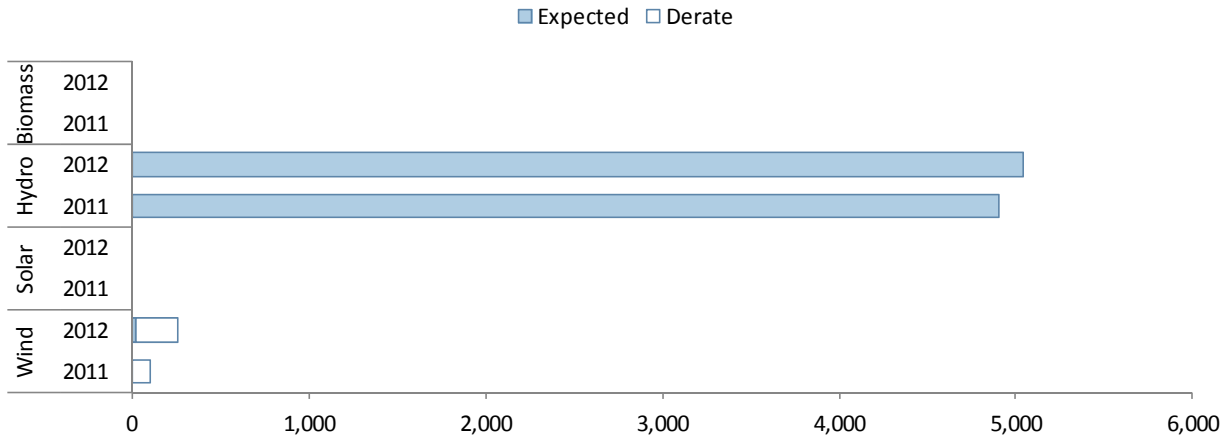


**Table 23: MRO-Manitoba Renewable Generation**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 0 | 20 | 0 | 0 | 4,901 | 5,042 | 0 | 0 |
| Derate | 104 | 236 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Nameplate** | **104** | **256** | **0** | **0** | **4,901** | **5,042** | **0** | **0** |

The expected on-peak capacity ranges for hydro resources are projected to fall between 4,951 MW and 4,984 MW during the summer season. The expected maximum capacity during this period is 5,086 MW.

## Capacity Transactions

All of Manitoba Hydro's dependable export capacity is backed by Firm contracts. There are no capacity imports projected for the summer season. These contractual agreements have Firm transmission associated with them. Manitoba Hydro does not project any capacity transactions beyond the contract terms. On-peak capacity transactions projected for the 2012 summer are included in Table 24.

**Table 24: MRO-Manitoba Capacity Transactions**

| Capacity Transactions | Imports | Exports | Net |
|---|---|---|---|
| Firm | 0 | 1,080 | -1,080 |
| Expected | 0 | 0 | 0 |
| **Total** | **0** | **1,080** | **-1,080** |

Manitoba Hydro's emergency energy imports are characterized under the MISO-Manitoba Hydro Contingency Reserve Sharing Group (CRSG) agreement. Only upon significant contingencies of generation or transmission facilities do Manitoba Hydro system operators have the ability to request emergency energy imports from MISO under the CRSG. Manitoba Hydro is its own Balancing Authority so all emergency energy imports would be from external Balancing Authorities in MISO. The total reserve carried in the reserve sharing group is 2,000 MW (150 MW for Manitoba Hydro, 1,850 MW for MISO). Manitoba Hydro is expected to exhaust its own available reserves prior to making an emergency energy request.

## Transmission

There are no project delays or temporary service outages that will impact reliability during the 2012 summer season. Additionally, Manitoba Hydro does not foresee any projects that will be needed to maintain or enhance reliability for the 2012 summer season.

## Operations

On an annual basis, Manitoba Hydro performs an operational study to determine the storage reserve requirements necessary to meet demand under the lowest historic flow on record and a high load forecast. There have been no unique operational problems observed. Additionally, there are no new operating procedures developed for the 2012 summer season. However, Manitoba Hydro has existing operating procedures for the two wind farms located in Manitoba.

Potential reliability concerns resulting from minimum demand and over generation include localized over voltage concerns in the northern Manitoba AC transmission system as well as hydraulic constraints on Lower Nelson. At minimum demand, forebay management at Lower Nelson River generating stations becomes a concern as a constrained ability to discharge water efficiently develops. Potential impacts include spill and forebay license violations.

To mitigate over voltage concerns, reactors could be switched on, capacitors switched off, transformer tap settings may be adjusted, or transmission lines may be removed from service.

Manitoba Hydro will curtail customers in response to system emergencies and to maintain planning and operating reserves. The industrial customers with CRP agreements are required to maintain the availability of the resources more than 95 percent of the time. No performance concerns are expected.

Various restrictions are placed on the resources based upon the CRP agreement between Manitoba Hydro and the specific industrial customers. Minimum notice to curtail load ranges between 5 minutes, 60 minutes, and 48 hours. Maximum duration per curtailment varies between 4 hours, 4.25 hours, and 10 days. The maximum daily hours of curtailment ranges between 6, 8, 10, and 24 hours. The maximum annual number of curtailments is 3, 15, or 25 times. The maximum annual hours of curtailment varies from 60, 63.75, 106.25, and 720.

There are no environmental or regulatory restrictions that would impact reliability. Finally, Manitoba Hydro does not anticipate any unusual operating conditions that could significantly impact reliability for the upcoming summer season.

## Vulnerability Assessment

As a predominately hydro region, Manitoba Hydro has an energy criterion that requires adequate energy resources to supply the Firm energy demand in the event that the lowest recorded coincident river flow conditions on the 96-year hydraulic flow record are repeated. In other words, the Manitoba Hydro system is designed and operated to serve all Firm load requirements under the worst inflow conditions on record coincident with high winter load conditions. Drought contingency plans are well established and operational concerns are not a factor.

Manitoba Hydro's system tends to be energy constrained rather than capacity constrained. As a result of the tendency to be energy constrained, there are typically significant amounts of surplus generation capacity available. Therefore it is possible to manage resources around significant long-term generator outages of capacity resources.

Manitoba Hydro's CRP is only used to meet reliability obligations. If these resources became unavailable, other sources of reserves internal to Manitoba Hydro and external via the MISO-Manitoba Hydro CRSG agreement would be used in emergency situations. With respect to resource adequacy, Manitoba Hydro does not rely on demand response resources when evaluating resource adequacy requirements.

The most likely increase in variable generation in the foreseeable future is wind related. The addition of new resource would help with resource adequacy issues and the addition of plausible amounts of wind generation does not raise any significant operational concerns given the significant operating flexibility of the existing hydro resources.

The Raven Lake MR11 Tripping SPS was installed at Raven Lake station in October 2011 with the SPS tripping function disabled. The MRO has approved placing this SPS into service. Manitoba Hydro is deciding on a suitable date to place the SPS in service. The purpose of this SPS is to prevent overloading of the 115 kV line MR11 under certain system contingencies. No system changes or reinforcements are currently planned that will allow this SPS to be retired or replaced.

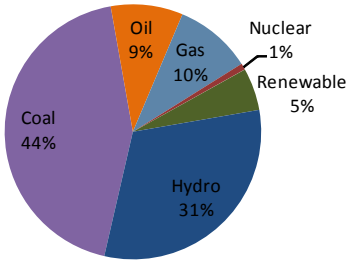
Manitoba Hydro does not anticipate any supply or transportation issues for the 2012 summer season. Alberta gas supplies and transportation to Manitoba are plentiful. TransCanada Pipeline has been

experiencing significant de-contracting of Firm transport by its customers. It has more than enough transport available should Manitoba Hydro have to run its gas-fired generation during the summer season. Gas supply is available either from Alberta or from the East via backhaul arrangements. Manitoba Hydro does not have any Firm arrangements in place for supply or transport at this time.

# MRO-MAPP

| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 7,027 | - |
| Future-Planned | 294 | - |
| Supply-Side Demand Response | 93 | - |
| Net Capacity Transactions | -1331.782 | - |
| **Anticipated** | **6,082** | **29.01%** |
| Existing-Other and Future-Other | 0 | 0 |
| **Prospective** | **6,082** | **29.01%** |
| **Reference Margin Level** | - | **15.00%** |

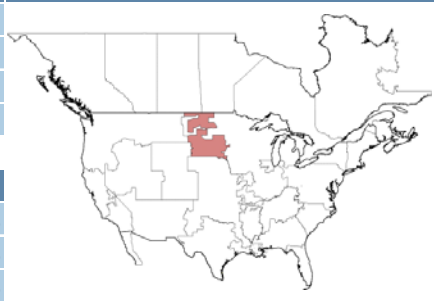
On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **5,027** | **4,715** |
| Demand-Side Demand Response (2012) | - | 84 |
| Supply-Side Demand Response (2011) | 60 | - |
| **Total Internal** | **5,087** | **4,799** |

| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 5,027 | -6.21% |
| Actual Peak Demand | 4,732 | -0.36% |
| All-Time Summer Peak Demand (August 1, 2007) | 6,249 | -24.55% |

Assessment Area Boundary



*Note: Additional information regarding the methods and assumptions used in the development of the MRO-MAPP seasonal assessment can be found in Appendix I and on the NERC website.*[75]

## Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the MAPP Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The Reserve Margins for the MAPP Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer season.

A total of 294 MW of capacity additions will be added through the summer of 2012. According to the MAPP demand forecast, Total Internal Demand has decreased from 4,997 MW to 4,799 MW since the 2011 summer. This equates to an annual growth rate of -4.0 percent.

## Planning Reserve Margins

MAPP is projecting adequate Planning Reserve Margins during the 2012 summer season. All reserve margin categories (Existing-Certain, Anticipated, Prospective) exceed the target reference margin of 15 percent. MAPP does not anticipate any scenarios that would lead to a significant detraction from these projections for the upcoming summer season. Table 25 includes the 2011 and 2012 reserve margins for the MRO-MAPP Assessment Area.

[75] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

**Table 25: MRO-MAPP Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 15.00% | 15.00% |
| Existing-Certain & Net Firm Transactions | 22.92% | 22.77% |
| Anticipated | 24.61% | 29.01% |
| Prospective | 24.61% | 29.01% |

## Demand

MAPP assumes normal (50/50) weather and normal economic assumptions. The 2011 MAPP actual summer peak non-coincident demand was 4,732 MW. Last summer's demand forecast was 5,087 MW, based on MRO-submitted data. This summer's peak demand forecast is 4,799 MW. Non-coincident, internal peak demands were used to aggregate individual LSE loads for use in the MAPP forecast. Resource evaluations are based on non-coincident peak demand conditions. Table 26 includes the demand forecast for the 2011 and 2012 summer for the MRO-MAPP Assessment Area.

**Table 26: MRO-MAPP Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| Net Internal | 5,027 | 4,715 | -312 | -6.21% |
| Total Internal | 5,087 | 4,799 | -288 | -5.67% |

## Demand-Side Management

The total amount of Demand Response that is expected to be available on-peak for the 2012 summer season is 177 MW. An additional 225 MW of Energy Efficiency is also projected to be available during the peak. Interruptible Demand and Demand-Side Management (DSM) programs amount to 8.4 percent of the MAPP Projected Total Internal Peak Demand of 4,799 MW. The month of July was used as the peak summer month in this assessment.

A wide variety of programs, including direct load control (such as electric appliance cycling) and interruptible load, may be used to reduce peak demand during the summer season. MAPP LSEs use various measurement and verification programs for demand response, such as those based upon International Performance Measurement and Verification Protocols (IPMVP). Energy Efficiency is verified through several means, such as use of the Minnesota Deemed Savings Database, provided by the Minnesota Office of Energy Security. Figure 29 and Table 27 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the MRO-MAPP Assessment Area.

**Figure 29: MRO-MAPP Demand Response**

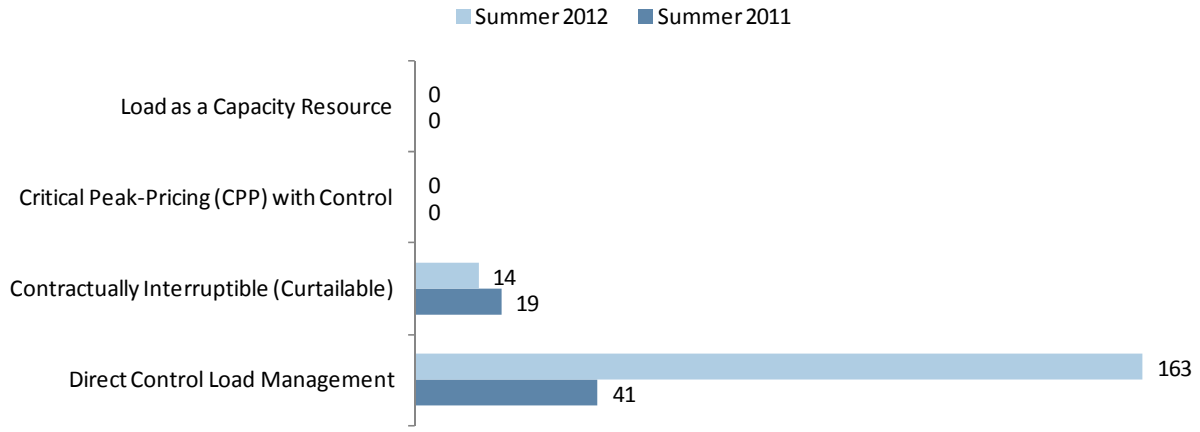



**Table 27: MRO-MAPP Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 41 | 84 | 79 |
| Contractually Interruptible (Curtailable) | 19 | 0 | 14 |
| Critical Peak-Pricing (CPP) with Control | 0 | 0 | 0 |
| Load as a Capacity Resource | 0 | 0 | 0 |
| **Total Demand Response** | **60** | **84** | **93** |
| **Percentage of Total Internal Demand** | **1.18%** | **1.75%** | **1.94%** |

There have not been any significant changes regarding dispatchable and controllable demand response, or demand response used for ancillary services, in MAPP. The amount of Demand-Side Management in these areas remains unchanged.

## Generation

The Existing-Certain capacity projections for the 2012 summer season are 7,027 MW. MAPP does not currently have Existing-Other or Existing-Inoperable capacity resources. The primary fuel sources in MAPP are coal (47 percent), hydro (29 percent), oil (11 percent), natural gas (9 percent), and wind (4 percent). There have been no Existing-Certain capacity additions since last season. Table 28 includes projections of MRO-MAPP resources for the 2011 and 2012 summer.

**Table 28: MRO-MAPP Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 6,823 | 7,027 |
| Future-Planned | 80 | 294 |
| Supply-Side Demand Response | 60 | 93 |
| Net Capacity Transactions | -926 | -1,332 |
| **Anticipated** | **6,037** | **6,082** |
| Existing-Other and Future-Other | 0 | 0 |
| **Prospective** | **6,037** | **6,082** |

There are 294 MW of Future-Planned capacity resources projected to be added either during or before the 2012 summer. There have been no unit retirements, deferments, or derates since the previous season.

Of the existing capacity resources, 303 MW of on-peak wind generation is expected from the total 1,155 MW of nameplate wind capacity. This dataset uses 10 years or the life of the wind farm.

Additionally, there are 3 MW of existing biomass capacity and 2,127 MW of hydro. No adverse hydro conditions are projected for the 2012 summer, with reservoirs returning to normal levels, after several seasons of below-normal conditions. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 30 and Table 29.

**Figure 30: MRO-MAPP Renewable Generation**

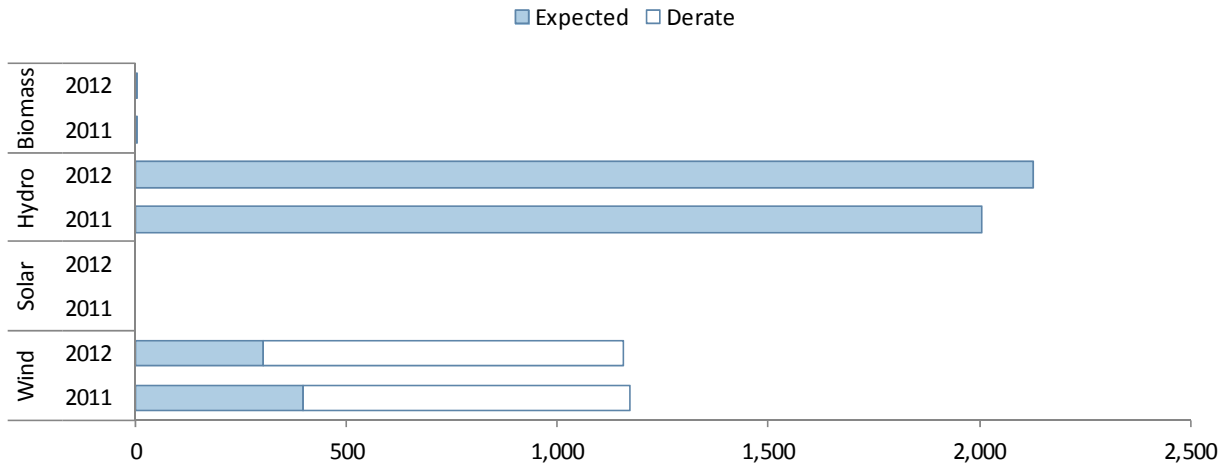



**Table 29: MRO-MAPP Renewable Generation**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 398 | 303 | 0 | 0 | 2,007 | 2,127 | 3 | 3 |
| Derate | 776 | 855 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Nameplate** | **1,173** | **1,158** | **0** | **0** | **2,007** | **2,127** | **3** | **3** |

MAPP is not expecting conditions that would reduce capacity for the 2012 summer season. MAPP does not anticipate any significant generating units to be out of service or retired during the 2012 summer season.

## Capacity Transactions

For the 2012 summer season, MAPP is projecting total Firm imports of 235 MW. Additionally, MAPP projects total Firm exports to amount to 1,567 MW. On-peak capacity transactions projected for the 2012 summer are included in Table 30.

**Table 30: MRO-MAPP Capacity Transactions**

| Capacity Transactions | Imports | Exports | Net |
|---|---|---|---|
| Firm | 235 | 1,567 | -1,332 |
| Expected | 0 | 0 | 0 |
| **Total** | **235** | **1,567** | **-1,332** |

## Transmission

The rebuilding of the 115 kV line from Charlie Creek – Watford City - Williston to 230 kV is expected to be in operation by the end of June 2012. Temporary operating guides will be developed as necessary to reliably manage this outage. Additionally, Northwestern Energy recently energized the Letcher Jct. – Mitchell 115KV line. This line was placed in service in December 2011. The project provides additional support and reliability to the Mitchell area.

MAPP is not aware of any transmission constraints or transmission issues that will affect system reliability (*i.e.*, deliverability of generation to network load).

## Operations

No significant operational issues are expected this summer for the MAPP Planning Authority area. The existing operating guides and temporary operating guides that are developed as needed, have maintained reliable system conditions throughout the year and will continue to be used this summer.

The MRO-MAPP Assessment Area does not anticipate any reliability concerns from minimum demand or over generation situations. MAPP does not anticipate any environmental or regulatory restrictions that would impact reliability this summer. Normal load levels are anticipated for the 2012 summer season and there are no concerns with resource adequacy or demand response in meeting projected peak demands.

## Vulnerability Assessment

MAPP plans to rely on current generation capacity margins and stable water levels this season. Overall, there are no resource adequacy or operational concerns for the following conditions: long-term (extended) drought; significant long-term generator outages; unresponsive or unavailable demand response; significant increases in variable generation. MAPP is unaware of any reliability impacts that would result specifically from environmental regulations.

MAPP does perform studies that consider known and anticipated fuel supply or delivery issues. Because the MAPP Planning Authority area has a diverse fuel supply, inventory management, and delivery methods, there is currently no specific mitigation procedure in place, should fuel delivery problems occur. Resource providers do not foresee any significant fuel supply and/or fuel delivery issues for the upcoming summer. Any fuel supply issues that may develop will be handled on a case-by-case basis.

Various MAPP reliability studies are performed in accordance with the MAPP Members Reliability Criteria and Study Procedures Manual.[76] Transient, voltage, and small signal stability studies[77] are performed as part of the near-term/long-term transmission assessments.[78] Reactive power resources are considered in on-going operational planning studies. No transient, voltage, or small signal stability issues are expected that impact reliability during the 2012 summer season.

All MAPP LSEs have established a Reference Margin Level through application of the MAPP Loss of Load Expectation (LOLE) Study. This study was last performed and completed by MAPP on December 31, 2009.[79] Similar to NERC's guidelines, the MAPP LOLE study recommends a 15 percent Reference Margin

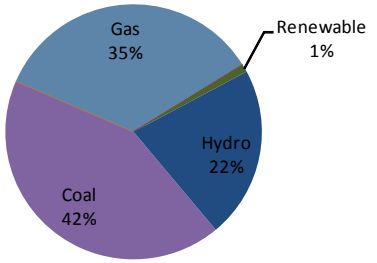
[76] MAPP Members Reliability Criteria and Study Procedures Manual, November, 2009.
[77] MAPP Small Signal Stability Analysis Project Report, November 2010.
[78] 2011 MAPP System Performance Assessment.
[79] MAPP Loss of Load Expectation Study 2010-2019, December 2009.

Level for predominantly thermal systems, and 10 Reference Margin Level for predominantly hydro systems.

# MRO-SaskPower

| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 3,544 | - |
| Future-Planned | 0 | - |
| Supply-Side Demand Response | 91 | - |
| Net Capacity Transactions | -50 | - |
| **Anticipated** | **3,585** | **23.50%** |
| Existing-Other and Future-Other | 0 | - |
| **Prospective** | **3,585** | **31.68%** |
| **Reference Margin Level** | - | **13.00%** |

On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **2,954** | **2,953** |
| Demand-Side Demand Response (2012) | - | 91 |
| Supply-Side Demand Response (2011) | 91 | - |
| **Total Internal** | **3,045** | **3,044** |

| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 2,954 | -0.05% |
| Actual Peak Demand | 2,988 | -1.18% |
| All-Time Summer Peak Demand (July 18, 2011) | 2,988 | -1.18% |

Assessment Area Boundary



*Note: Additional information regarding the methods and assumptions used in the development of the MRO-SaskPower seasonal assessment can be found in Appendix I and on the NERC website.*[80]

## Assessment Area Highlights

This assessment presents summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the province of Saskatchewan. Projections are based on internal SaskPower data, economic indicators, long-term weather forecasts, and historic load data.

The reserve margins for the Saskatchewan Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer season.

No capacity additions will be added during the 2012 summer. According to the SaskPower demand forecast, Total Internal Demand has increases from 3,045 MW to 3,134 MW since last summer. This equates to an annual growth rate of 1.03 percent.

## Planning Reserve Margins

An adequate Planning Reserve Margin is projected for Saskatchewan during the 2012 summer season. The SaskPower Reference Margin Level for Saskatchewan is 13 percent, while all reserve margin categories exceed 17 percent throughout the summer. The peak month considered for this assessment is July, at which point the Anticipated Reserve Margin is 23.5 percent. However, the Anticipated Reserve Margin does drop to 17 percent in September. Adequate resources have been planned for Saskatchewan to meet anticipated load for the 2012 summer period. Additionally, there are no anticipated challenges that would lead to significant reductions of the reserve margin projections for

[80] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

Saskatchewan during the 2012 summer. Table 31 includes the 2011 and 2012 reserve margins for the MRO-SaskPower Assessment Area.

**Table 31: MRO-SaskPower Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 15.00% | 13.00% |
| Existing-Certain & Net Firm Transactions | 17.73% | 23.50% |
| Anticipated | 17.73% | 23.50% |
| Prospective | 17.73% | 31.68% |

## Demand

For Saskatchewan, the peak Total Internal Demand forecast for 2011 summer assessment period was 3,045 MW, while the actual peak demand for the 2011 summer assessment period was 2,988 MW. The peak demand forecast for all four months of the 2012 summer period is 3,043 MW. This higher demand forecast is due to industrial load and residential load growth. In general, load growth in Saskatchewan, is due primarily to economic growth in the industrial sector. Table 32 includes the demand forecasts for the 2011 and 2012 summers.

**Table 32: MRO-SaskPower Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| Net Internal | 2,954 | 2,953 | -1 | -0.05% |
| Total Internal | 3,045 | 3,044 | -1 | -0.05% |

## Demand-Side Management

The total amount of Demand Response and Energy Efficiency (New Conservation) that is expected to be available on peak for Saskatchewan for the 2012 summer season is 134 MW. Demand Response and Energy Efficiency (New Conservation) resources in Saskatchewan are considered capacity resources used for peak shaving. Figure 31 and Table 33 present the Demand Response forecasted for the 2011 and 2012 summer peaks.

**Figure 31: MRO-SaskPower Demand Response**

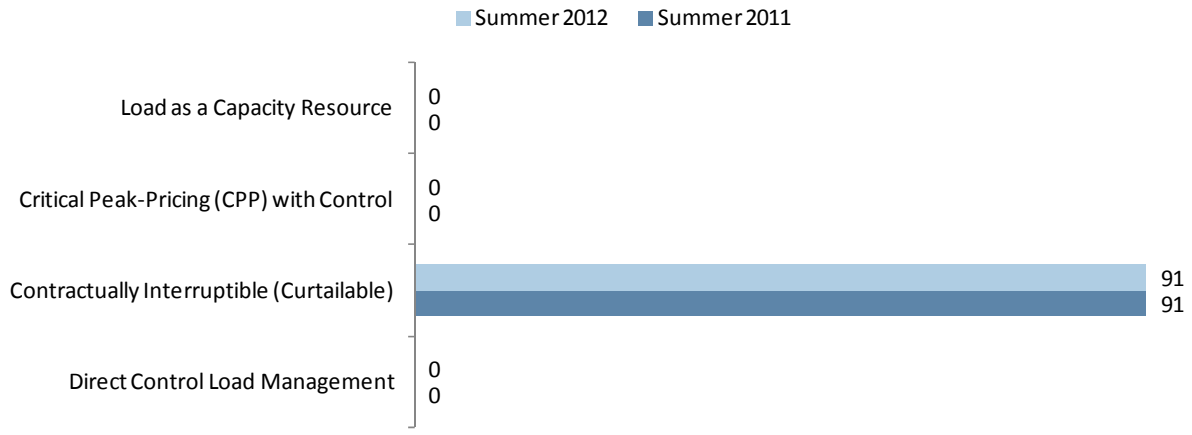


**Table 33: MRO-SaskPower Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 0 | 0 | 0 |
| Contractually Interruptible (Curtailable) | 91 | 91 | 0 |
| Critical Peak-Pricing (CPP) with Control | 0 | 0 | 0 |
| Load as a Capacity Resource | 0 | 0 | 0 |
| **Total Demand Response** | **91** | **91** | **0** |
| **Percentage of Total Internal Demand** | **2.99%** | **2.99%** | **0.00%** |

The primary driver for Demand-Side Management programs in Saskatchewan is economic incentive.[81] Increases in Demand-Side Management (DSM) for the 2012 summer assessment period will come from growth of existing programs.

## Generation

In Saskatchewan, 3,647 MW of Existing-Certain capacity is expected to be available during the peak month. Approximately 237 MW of wind derates, hydro derates, and scheduled outages for maintenance are expected on peak. No resources are expected to be inoperable for this summer. Table 34 includes resource forecasts for the 2011 and 2012 summer.

**Table 34: MRO-SaskPower Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 3,544 | 3,647 |
| Future-Planned | 0 | 0 |
| Supply-Side Demand Response | 91 | 0 |
| Net Capacity Transactions | -50 | 0 |
| **Anticipated** | **3,585** | **3,647** |
| Existing-Other and Future-Other | 0 | 0 |
| **Prospective** | **3,585** | **3,647** |

The primary sources of fuel for Saskatchewan are coal, hydro, and natural gas. Since the 2011 summer assessment period, 89 MW of natural gas generation has been added. However, there is no Future-Planned capacity projected to be added leading up to, or during the 2012 summer season. Additionally, there are no anticipated unit retirements, project deferments, or any other impacts that would affect the existing capacity level since the 2011 summer assessment period. Unit derates similar to the prior season are expected. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 32 and Table 35.

[81] The difference in cost between providing the DSM program and the cost of serving the load.

**Figure 32: MRO-SaskPower Renewable Generation**

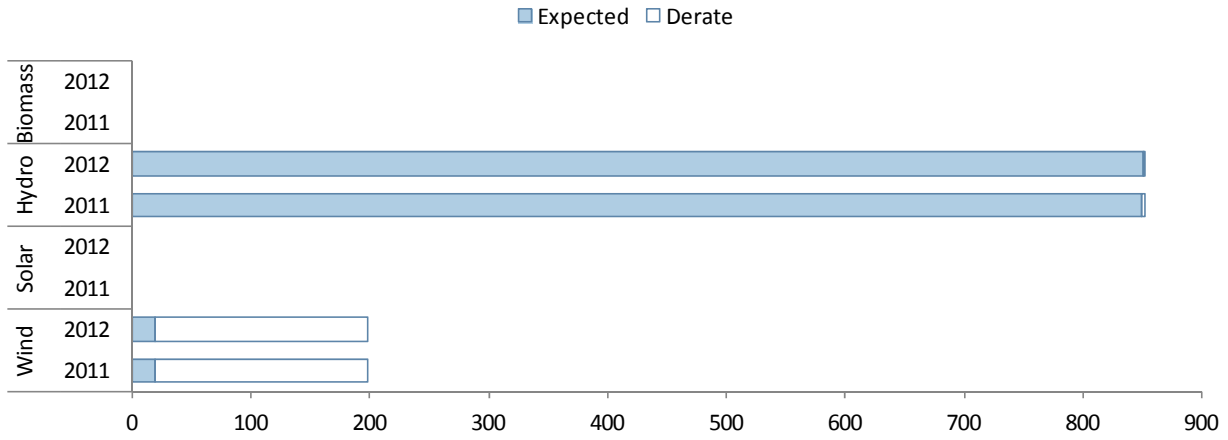



**Table 35: MRO-SaskPower Renewable Generation**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 20 | 20 | 0 | 0 | 850 | 851 | 0 | 0 |
| Derate | 178 | 178 | 0 | 0 | 2 | 2 | 0 | 0 |
| **Nameplate** | **198** | **198** | **0** | **0** | **852** | **853** | **0** | **0** |

There are no units that will be taken out of service or brought back into service during the 2012 summer season in Saskatchewan, other than those that are part of the regular maintenance plan. For Saskatchewan, an average of 20 MW of wind and an average of 850 MW of hydro is expected on-peak during the 2012 summer season. For the 2012 summer season, Saskatchewan plans for 10 percent of wind nameplate capacity to be available to meet on-peak demand. On-peak expected values for hydro assume nameplate net generation less expected seasonal derates due to water conditions.

## Capacity Transactions

There are no Firm imports and/or exports backed by contracts, projected during the 2012 summer season.

## Transmission

There are no project delays or temporary transmission service outages in Saskatchewan that are expected to impact reliability during the 2012 summer season. Additionally, there are no specific projects that have been identified to maintain or enhance reliability during the 2012 summer season.

## Operations

No special operating study requirements for Saskatchewan have been identified for the 2012 summer season. There have been no new operating procedures developed as a result of integration of variable resources. No potential reliability concerns resulting from minimum demand or over generation have been identified.

There are no concerns with the use of demand response resources to meet peak demand for the 2012 summer season for Saskatchewan. Operational procedures for the 2012 summer season will not be impacted as a result of integrating variable resources for Saskatchewan. No environmental and/or

regulatory restrictions are anticipated to impact reliability for the 2012 summer season for Saskatchewan.

## Vulnerability Assessment

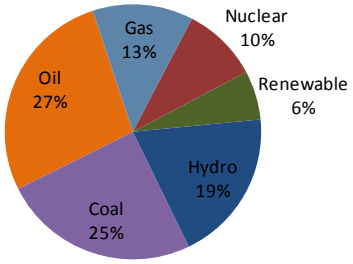
With regards to coordination with the fuel supply industry, coal resources have Firm contracts, are mine-to-mouth, and stockpiles are maintained at each facility in the event that mine operations are unable to meet the required demand of the generating facility. Typically there are 20 days of on-site stockpile for each of the coal facilities which in total represent approximately 47 percent of total provincial installed capacity. Strip coal reserves are also available and only need to be loaded and hauled from the mine. These reserves range from 30 to 65 days depending on the plant.

Natural gas resources have Firm on-peak transportation contracts with large natural gas storage facilities located within the province to back the contracts.

# NPCC-Maritimes

| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 4,599 | - |
| Future-Planned | 0 | - |
| Supply-Side Demand Response | 222 | - |
| Net Capacity Transactions | 0 | - |
| **Anticipated** | **4,821** | **42.13%** |
| Existing-Other and Future-Other | 0 | - |
| **Prospective** | **4,821** | **42.13%** |
| **Reference Margin Level** | - | **15.00%** |

On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **3,553** | **3,392** |
| Demand-Side Demand Response (2012) | - | 0 |
| Supply-Side Demand Response (2011) | 0 | - |
| **Total Internal** | **3,553** | **3,392** |

| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 3,553 | -4.5% |
| Actual Peak Demand | 3,329 | 1.9% |
| All-Time Summer Peak Demand (July 31, 2007) | 3,576 | -5.1% |

Assessment Area Boundary



*Note: Additional information regarding the methods and assumptions used in the development of the NPCC-Maritimes seasonal assessment can be found in Appendix I and on the NERC website.*[82]

## Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the Maritimes Assessment Area which consists of four sub-regions. Data was collected from individual sub-region and aggregated using a bottom-up approach with projections based on long-term weather forecasts, and historic load data. It should be noted that the Maritimes Area is a winter-peaking system and, as such, does not expect to experience any reliability issues.

The reserve margins for the Maritimes Assessment Area are based in accordance with NPCC Directory #1 Appendix F Procedure for Operational Planning Coordination. As such, the assessment considers the regional operating reserve criteria; 100 percent of the largest single contingency and 50 percent of the second largest contingency. Whereas, the Maritimes Area is a winter-peaking system and there are more than sufficient reserve margins anticipated over this assessment period.

A total of 31.05 MW of capacity additions will be added during the 2012 summer. According to the Maritimes Area demand forecast, Total Internal Demand has decreased from 3,553 MW to 3,392 MW since the 2011 summer. This equates to a decrease rate of 4.5 percent. This decrease can be primarily attributed to the loss of industrial load.

## Planning Reserve Margins

When allowances for unplanned outages (based on a discreet MW value representing an historical assessment of the total forced outages in MW typically realized at the time of peak for the given

[82] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

operating season) are considered, the Maritimes Area is projecting more than adequate surplus capacity margins above its operating reserve requirements for the 2012 Summer assessment period.

The projected reserve margin for 2012 Summer period range from 42 percent to 52 percent as compared to the projected capacity margin for the 2011 Summer of 59 percent. Table 36 includes the 2011 and 2012 reserve margins for the MRO-Maritimes Assessment Area.

**Table 36: MRO-Maritimes Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 15.00% | 15.00% |
| Existing-Certain & Net Firm Transactions | 58.91% | 42.13% |
| Anticipated | 58.91% | 42.13% |
| Prospective | 58.91% | 42.13% |

The Maritimes Area is a winter-peaking system and has a very diverse fuel supply made up of nuclear (scheduled back in service October 2012), natural gas, coal, oil (both light and residual), pet-coke, hydro, tidal, municipal waste, wind and wood. As such does not expect to experience any reliability issues.

## Demand

The Maritimes Area forecasted a peak demand of 3,553 MW to occur during the 2011 summer period, June through September and it was expected to occur during the week of September 25, 2011. The actual peak for 2011 summer was 3,329 on July 21, 2011, which was 224 MW (6.3 percent) lower than the forecasted peak demand. The primary driver in the difference of peaking in July and not September as forecasted was the shutdown of a large industrial load at the beginning of September. The summer 2012 summer peak forecast is 3,392 MW. The 161 MW reduction is due to the loss of industrial load. See Table 37 for 2011 and 2012 summer demand values.

**Table 37: MRO-Maritimes Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| Net Internal | 3,553 | 3,392 | -161 | -4.53% |
| Total Internal | 3,553 | 3,392 | -161 | -4.53% |

## Demand-Side Management

In the Maritimes Area there is between 207 MW and 275 MW of interruptible demand available during the assessment period; there is 222 MW forecasted to be available at the time of the Maritimes Area seasonal peak. This is approximately 7 percent of the Total Internal Demand. The interruptible load demand that is used is from industrial loads that are metered and therefore can be monitored to determine what level of load would be available to curtail under emergency operating conditions. Figure 33 and Table 38 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the MRO-Maritimes Assessment Area.

**Figure 33: MRO-Maritimes Demand Response**

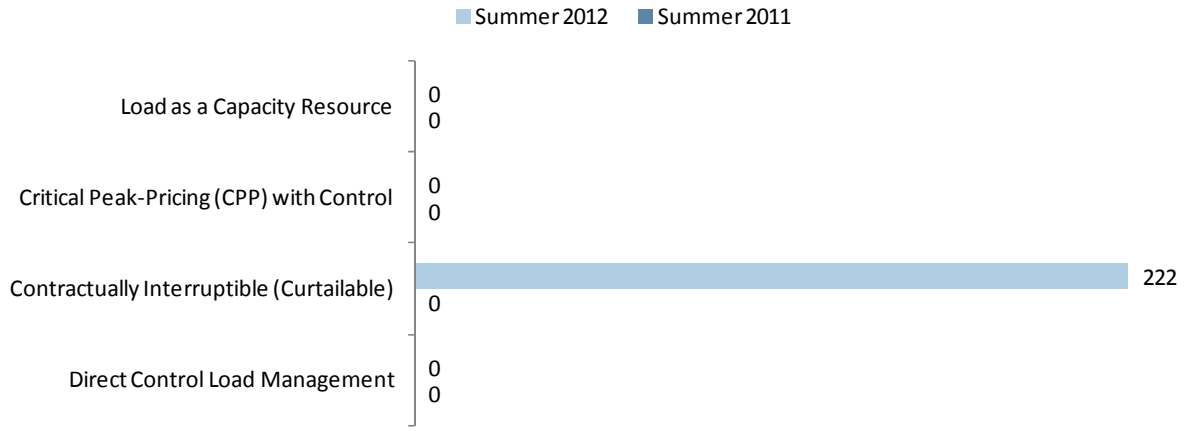



**Table 38: MRO-Maritimes Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 0 | 0 | 0 |
| Contractually Interruptible (Curtailable) | 0 | 0 | 222 |
| Critical Peak-Pricing (CPP) with Control | 0 | 0 | 0 |
| Load as a Capacity Resource | 0 | 0 | 0 |
| **Total Demand Response** | **0** | **0** | **222** |
| **Percentage of Total Internal Demand** | **0.00%** | **0.00%** | **6.54%** |

The Maritimes Area is broken up into sub-areas and each sub-area has its own energy efficiency programs. These programs are primarily aimed at the residential consumer to help reduce their heating costs. It is usually geared towards heat, as the Maritimes Area is a winter-peaking system.[83]

## Generation

The Maritimes Area resources will be 7,457 MW of existing capacity. The Maritimes Area only considers Existing-Certain resources when doing its seasonal assessment. As indicated above the Maritimes Area has a very diverse fuel supply with primary sources of fuel being hydro, oil, coal, natural gas and nuclear.

Existing-Certain resources that have been added since summer 2011 include 49 MW of natural gas and 41.36 MW of wind generation. There are 31.05 MW of planned wind generation expected to be added during the summer 2012 reporting period. Since the last summer assessment a coal fired plant of 299 MW is scheduled to be retired on May 31, 2012. Table 39 includes projections of resources in the Maritimes Assessment Area for the 2011 and 2012 summer.

[83] For further information on the energy efficiency programs please review the links: www.maritimeelectric.com; www.nppower.com; www.mainepublicservice.com; www.emec.com; www.nspower.ca/energy_efficiency/programs/.

**Table 39: MRO-Maritimes Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 5,853 | 4,599 |
| Future-Planned | 0 | 0 |
| Supply-Side Demand Response | 0 | 222 |
| Net Capacity Transactions | -207 | 0 |
| **Anticipated** | **5,646** | **4,821** |
| Existing-Other and Future-Other | 0 | 0 |
| **Prospective** | **5,646** | **4,821** |

Point Lepreau nuclear generator has been off line for refurbishment since April 1, 2008 and it is scheduled back on line October 2012. The expected installed capacity once Point Lepreau has returned to service is to be approximately 700 MW. In addition, a thermal plant (units 96 MW + 203 MW = 299 MW) is scheduled to be retired on May 31, 2012.

Wind capacity within the Maritimes Assessment Area is expected to be 846 MW with 138.57 MW expected on peak. Wind projected capacity is derated to its demonstrated average output for each summer or winter capability period. In New Brunswick, Prince Edward Island and Northern Maine Independent System Administrator (NMISA) the wind facilities that have been in production over an extended period of time a derated monthly average is calculated using metering data from previous years over each seasonal assessment period. Nova Scotia has decided not to include any wind facilities towards their installed capacity (100 percent derated). A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 34 and Table 40.

**Figure 34: MRO-Maritimes Renewable Generation**

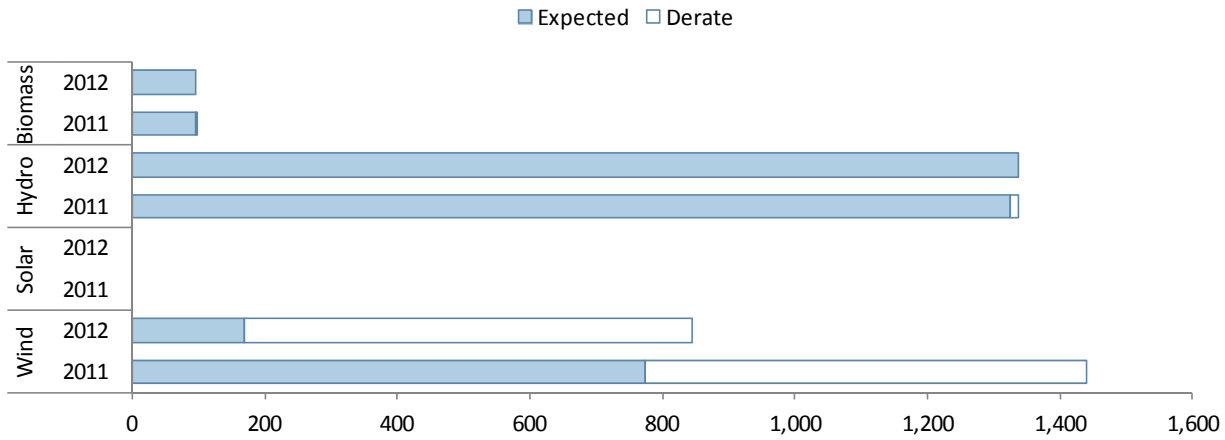



**Table 40: MRO-Maritimes Renewable Resources**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 774 | 170 | 0 | 0 | 1,325 | 1,338 | 96 | 96 |
| Derate | 665 | 676 | 0 | 0 | 12 | 0 | 3 | 0 |
| **Nameplate** | **1,439** | **846** | **0** | **0** | **1,337** | **1,338** | **99** | **96** |

For those wind facilities that have not been in service that length of time, the derating of wind capacity in the Maritimes Area is based upon results from the Sept. 21, 2005 NBSO report *Maritimes Wind*

*Integration Study*.[84] This wind study showed that the effective capacity from wind projects, and their contribution to LOLE, was equal to or better than their seasonal capacity factors. Coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area receiving a higher capacity benefit from wind projects versus a summer peaking area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects in order to mitigate the occurrences of having zero wind production. Wind is the only variable resource currently considered in the Maritimes Area resource adequacy assessment. The amount of wind presently operating does not require any special operational changes.

## Capacity Transactions

No on-peak capacity transactions have been scheduled at this time. The Maritimes, through existing agreements with neighboring Balancing Authority areas, namely, ISO-NE and TransÉnergie, has established procedures for the acquisition of emergency energy if necessary.

## Transmission

No new transmission projects are scheduled to go into service during the 2012 summer period and no outages that would be expected to impact reliability are scheduled.

## Operations

Anticipated 2012 summer conditions do not show the need for any special operating studies. The Maritimes Assessment Area assesses its seasonal resource adequacy in accordance with NPCC Directory #1 Appendix F Procedure for Operational Planning Coordination. As such, the assessment considers the regional Operating Reserve criteria; 100-percent of the largest single contingency and 50-percent of the second largest contingency. The amount of wind presently operating does not require any special operational changes.

The Maritimes area does not anticipate any reliability concerns due to minimum demand and over generation. There are adequate generation facilities within the Maritimes that can easily be removed from service to prevent that from happening.

The only demand response considered in resource adequacy assessment for the Maritimes Area is interruptible load. The Maritimes Area uses a 20 percent reserve criterion for planning purposes, equal to 20 percent x (Forecast Peak Load MW – Interruptible Load MW).

There are no environmental or regulatory restrictions which could impact reliability in the Maritimes Area during the assessment period. There are no unusual operating conditions anticipated for the summer that will impact reliability in the Maritimes Area.

## Vulnerability Assessment

The Maritimes Area is forecasting normal hydro conditions for the 2012 Summer assessment period. The Maritimes Area hydro resources are run-of-the-river facilities with limited reservoir storage facilities. These facilities are primarily utilized as peaking units or for providing operating reserve.

The Maritimes Area is a winter-peaking system. The summer months are when significant long-term generator outages are planned. Load Management is not included in the resource adequacy assessment for the Maritimes Area. The interruptible load demand that is used is from industrial loads that are

[84] http://www.nbso.ca/Public/_private/2005%20Maritime%20Wind%20Integration%20Study%20_Final_.pdf.

metered and therefore can be monitored to determine what level of load would be available to curtail under emergency operating conditions.

The amount of wind presently operating does not require any special operational changes. If there were a significant increase of wind the New Brunswick System Operator, as Reliability Coordinator for the Maritimes Area, has the authority to curtail the variable generator as required.

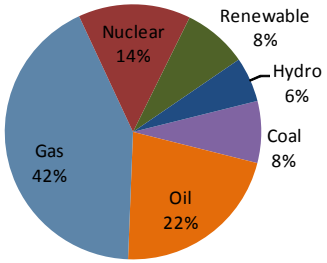
The Maritimes Area closely monitors air emissions and other environmental discharges to ensure compliance with standards and limits set forth by Canadian Federal and Provincial environmental regulations. For the 2012 Summer Operating Period, there may be occasions when some units are required to be derated in order to meet these regulations. However, these occasions are expected to be infrequent, of short duration and are not included in the summer assessment.

It is the responsibility of the generator owners to ensure that fuel supplies are adequate. The Maritimes Assessment Area does not consider potential fuel-supply interruptions in this assessment. The fuel supply in the Maritimes Assessment Area is very diverse and includes nuclear, natural gas, coal, oil (both light and residual), pet-coke, hydro, tidal, municipal waste, wind and wood.

# NPCC-New England (ISO-NE)

| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 31,644 | - |
| Future-Planned | 137 | - |
| Supply-Side Demand Response | 1,128 | - |
| Net Capacity Transactions | 676 | - |
| **Anticipated** | **33,585** | **26.92%** |
| Existing-Other and Future-Other | 0 | 0 |
| **Prospective** | **34,815** | **31.57%** |
| **Reference Margin Level** | - | **15.00%** |

On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **26,776** | **26,462** |
| Demand-Side Demand Response (2012) | - | 978 |
| Supply-Side Demand Response (2011) | 2,035 | - |
| **Total Internal** | **28,811** | **27,440** |

| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 26,776 | -1.17% |
| Actual Peak Demand | 27,707 | -4.49% |
| All-Time Summer Peak Demand (August 2, 2006) | 28,130 | -5.93% |

Assessment Area Boundary



*Note: Additional information regarding the methods and assumptions used in the development of the NPCC-New England (ISO-NE) seasonal assessment can be found in Appendix I and on the NERC website.*[85]

## Assessment Area Highlights

Reserve Margins for the ISO New England (ISO-NE) Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer season.

A total of 137 MW of capacity additions will be added prior to the 2012 summer. According to the ISO-NE's demand forecast, Total Internal Demand has decreased from 26,776 MW to 26,462 MW since the 2011 summer, a change of -1.2 percent. The forecasted demand values in this report take into account reductions due to passive demand resources (energy efficiency) with capacity supply obligations in ISO-NE's Forward Capacity Market. If the passive DR amounts of 978 MW in 2012 and 774 MW in 2011 were included in the forecast, the forecasted peak demands for 2012 and 2011 would be 27,440 MW and 27,550 MW, respectively.

During the 2012 summer, there are no projections of any significant transmission lines being out of service that could negatively impact regional reliability. Reduced and uncertain fuel supplies to Northeast Massachusetts/Boston resources will cause local capacity margins to be tight under high load conditions.

## Planning Reserve Margins

ISO New England expects to have an adequate Planning Reserve Margin during the 2012 summer. The margins for Anticipated Capacity Resources range from a low of 26.9 percent in July to a high of 38.3

[85] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

percent in September. The main reason for this difference is the lower demand forecast in September, due to the typically cooler weather. Table 41 includes the 2011 and 2012 reserve margins for the New England Assessment Area.

**Table 41: NPCC-New England (ISO-NE) Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 15.00% | 15.00% |
| Existing-Certain & Net Firm Transactions | 18.91% | 26.40% |
| Anticipated | 18.91% | 26.92% |
| Prospective | 18.95% | 31.57% |

New England does not have a fixed capacity or reserve margin requirement; rather it projects its capacity needs to meet the NPCC once in ten-year loss of load expectation (LOLE) resource planning reliability criterion. The capacity needs can vary from year to year depending on system conditions. Therefore, for the purposes of this report, the reference margin level is considered to be 15 percent, which is the target reserve margin assigned by NERC for predominantly thermal systems.

## Demand

Last year's reference summer peak demand forecast was 26,776 MW. This was 1,671 MW (5.9 percent) lower than ISO-NE's reconstituted 2011 summer peak demand of 28,447 MW, which occurred on July 22. The metered peak demand of 27,707 MW reflects reductions of 710 MW due to real-time demand response resources that were activated that day as part of ISO-NE's Operating Procedure 4 (OP 4) and 30 MW of Real-Time Price Response. A key factor driving higher than forecasted peak demand was record heat within New England. Table 42 includes the demand forecasts for the 2011 and 2012 summers for the New England Assessment Area.

**Table 42: NPCC-New England (ISO-NE) Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| Net Internal | 26,776 | 26,462 | -314 | -1.17% |
| Total Internal | 28,811 | 26,462 | -2,349 | -8.15% |

The 2012 reference summer peak demand forecast of 26,462 MW is 314 MW (1.2 percent) lower than the 2011 summer peak demand forecast of 26,776 MW. The key factor leading to this decreased forecast is the slower than expected growth following the region-wide economic recession. State load growth is determined by each state's economic conditions/forecast and the relationship between the two, as captured by ISO-NE's econometric models and Moody's state economic forecasts.

## Demand-Side Management

For the 2012 summer, there are 1,128 MW of active demand resources that are expected to be available on peak. Not included in this assessment is voluntary demand that may interrupt based on the price of wholesale energy. As of March 1, 2012, there were approximately 58 MW enrolled in the ISO-NE's price response program. Demand resources are treated as capacity in ISO-NE's FCM.

In addition to the active demand resources, ISO-NE has 978 MW of passive demand resources (*i.e.* energy efficiency & conservation), which are treated as demand reducers in this report. These include installed measures (*e.g.*, products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical

energy used during on-peak hours. As noted in the Methods and Assumptions (Part II), ISO New England has established a new long-term forecast method for energy efficiency, which takes into account the potential impacts of growing Energy Efficiency/Conservation initiatives in the assessment area. However, in the near-term (*i.e.*, up to three years in the future), the amount of energy efficiency is based on capacity supply obligations in the FCM.

The 1,128 MW of active demand resources consist of real-time demand response and real-time emergency generation, which can be activated with the implementation of ISO-NE Operating Procedure No. 4 - Action during a Capacity Deficiency (OP 4). These active DR can be used to help mitigate an actual or anticipated capacity deficiency. OP 4 Action 2 is the dispatch of Real-Time Demand Resources, which is implemented in order to manage operating reserve requirements. Action 6, which is the dispatch of Real-Time Emergency Generation Resources, may be implemented to maintain 10-minute reserve. Figure 35 and Table 35 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the New England Assessment Area.

**Figure 35: NPCC-New England (ISO-NE) Demand Response**

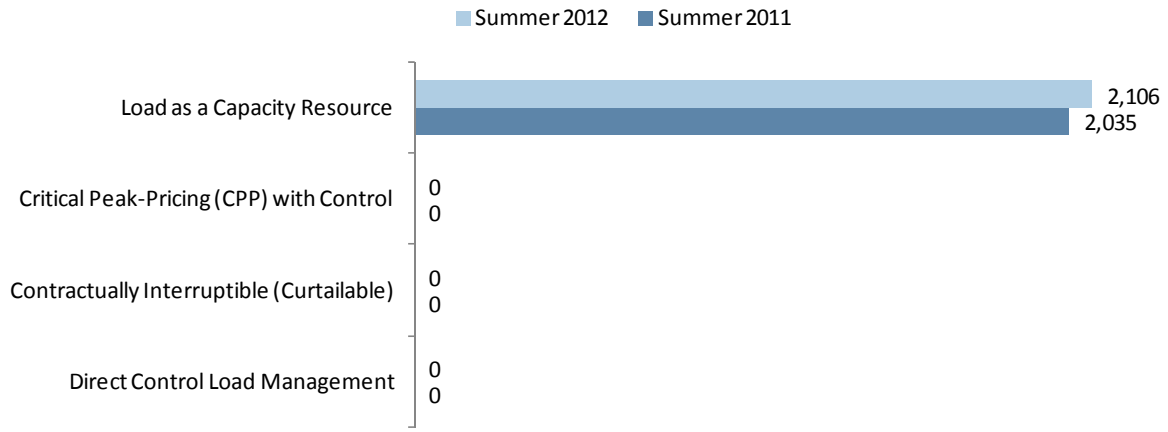



**Table 43: NPCC-New England (ISO-NE) Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 0 | 0 | 0 |
| Contractually Interruptible (Curtailable) | 0 | 0 | 0 |
| Critical Peak-Pricing (CPP) with Control | 0 | 0 | 0 |
| Load as a Capacity Resource | 2,035 | 978 | 1,128 |
| **Total Demand Response** | **2,035** | **978** | **1,128** |
| **Percentage of Total Internal Demand** | **7.06%** | **3.70%** | **4.26%** |

Some assets in the real-time demand response programs are under direct load control by the load response providers (LRP). The LRP implements direct load control of these assets upon dispatch instructions from ISO-NE, for example, interruption of central air conditioning systems in residential and commercial facilities.

The ISO presently does not permit demand response to be used for Ancillary Services. However, the option of allowing demand response to participate in the reserve market, and possibly for frequency regulation, is something that may be considered in the future.

## Generation

ISO New England has adequate capacity consisting of Existing-Certain generation (31,644 MW), Future-Planned generation (137 MW), demand resources (1,128 MW) and net imports (676 MW) to meet the demand of 26,462 MW throughout the summer season. The lowest Anticipated Reserve Margin of 7,123 MW (26.9 percent) occurs in the month of July. ISO New England ensures that it has enough capacity to meet system needs through its Forward Capacity Market (FCM). The amount of capacity that is needed to meet the once in ten-year disconnection of Firm load resource planning reliability criterion is purchased through annual auctions three years in advance of the year of interest. After this primary auction, there are Annual Reconfiguration Auctions prior to the commencement year, in order to re-adjust installed capacity purchases and ensure that adequate capacity will be purchased to meet system needs.

ISO-NE's Existing-Certain generating capacity during the month of July amounts to 31,644 MW based on Summer Seasonal Claimed Capability ratings. An additional 1,230 MW of capacity consists of wind, solar and hydro derates, and as well as 188 MW of planned generator maintenance. There is no Existing-Inoperable capacity. Table 44 provides the resource projections for the 2011 and 2012 summers.

**Table 44: NPCC-New England (ISO-NE) Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 29,590 | 31,644 |
| Future-Planned | 0 | 137 |
| Supply-Side Demand Response | 2,035 | 1,128 |
| Net Capacity Transactions | 1,136 | 676 |
| **Anticipated** | **32,761** | **33,585** |
| Existing-Other and Future-Other | 0 | 0 |
| **Prospective** | **32,761** | **34,815** |

Natural gas-fired generation represents the largest component of ISO New England's total installed capacity at 43.0 percent (13,764 MW), followed by oil-fired generation at 21.6 percent (6,895 MW), nuclear generation at 14.5 percent (4,628 MW), and coal at 7.8 percent (2,484 MW). Hydroelectric capacity (1,483 MW) and pumped-storage capacity (1,698 MW) make up 4.6 percent and 5.3 percent of the total, respectively. The remaining 3.2 percent of capacity consists of renewable capacity such as that provided by wind or biomass facilities.

A total of 66 MW of new generation has been installed since last summer. Most of that capacity (62 MW summer capability, or 217 MW nameplate rating) consists of wind facilities. With these additions, the total 2012 summer on-peak wind capacity is 97 MW. Another 2 MW of the new generation is solar capacity, bringing the total solar capacity to 5 MW. It is expected that 130 MW of gas-fired combustion turbines and an 8 MW fuel cell plant will become commercial before or during the 2012 summer.

AES Thames, a 181 MW coal plant, ceased operation in early 2011. Its capability is currently zero and is not included in the reserve margin calculations. The reserve margin for summer 2012 is above the Reference Margin Level without AES Thames; therefore the loss of this plant is not a concern.

ISO-NE has not approved any noteworthy long-term generator outages that would impact the 2012 summer period. Additionally, ISO-NE does not have any information about behind-the-meter generation, other than Real-Time Emergency Generation (RTEG). RTEG is a form of distributed generation that is classified as an active demand resource in the Forward Capacity Market, and is dispatched by ISO-NE during implementation of OP 4. A total of 435 MW of RTEG has an obligation to provide capacity in summer 2012.

Within the Existing-Certain category, approximately 97 MW of capacity is wind generation that is expected to be available at the time of peak demand. This reflects a 469 MW derate on-peak, from the total nameplate capability of 566 MW. Solar generation makes up 5 MW of on-peak capacity, derated from its nameplate capacity of 18 MW. Existing-Certain capacity also includes 1,483 MW of hydro-electric resources. This reflects a 560 MW derate on-peak, from the total nameplate capability of 2,043 MW. Biomass capacity in the Existing-Certain category totals 907 MW. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 36 and Table 45.

**Figure 36: NPCC-New England (ISO-NE) Renewable Generation**

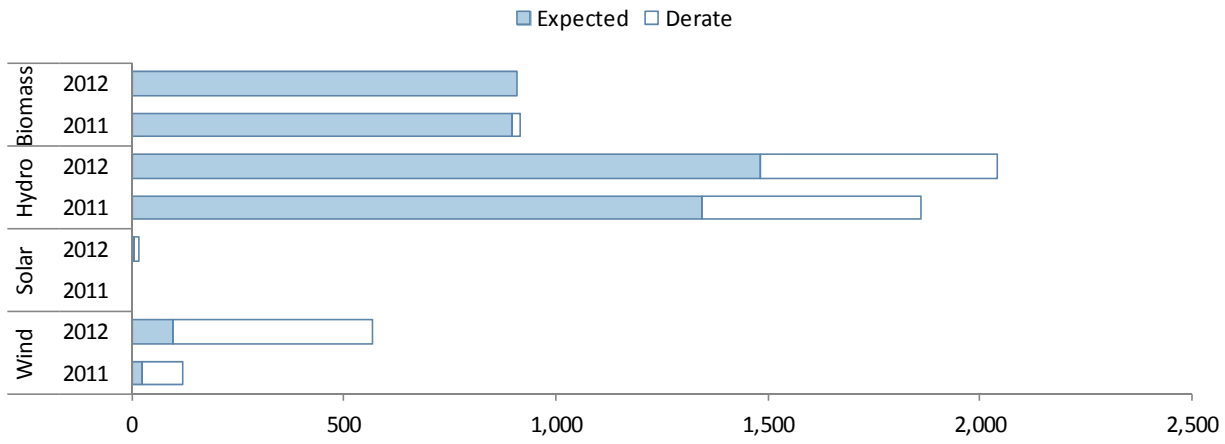



**Table 45: NPCC-New England (ISO-NE) Renewable Resources**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 26 | 97 | 0 | 5 | 1,346 | 1,483 | 897 | 907 |
| Derate | 93 | 469 | 0 | 13 | 517 | 560 | 18 | 0 |
| **Nameplate** | **119** | **566** | **0** | **18** | **1,863** | **2,043** | **915** | **907** |

ISO-NE continues to integrate new power supply sources, including new variable resources, into the network. All new resources are studied in detail by ISO-NE Operations Engineering prior to commercial operation. They are all integrated through the use of operating guides / interface limits and through ISO-NE's Energy Management System (EMS).

## Capacity Transactions

The forecast for 2012 summer on-peak Firm capacity imports is 776 MW. These Firm capacity imports, which include 465 MW from Hydro-Québec and 311 MW from New York, have been contracted for delivery within the 2012/2013 FCM Capability Period. Additionally, there are 100 MW of net Firm

exports projected for the 2012 summer. New England's capacity transactions for the 2012 summer are shown in Table 46.

**Table 46: NPCC-New England (ISO-NE) Capacity Transactions**

| Capacity Transactions | Imports | Exports | Net |
|---|---|---|---|
| Firm | 776 | 100 | 676 |
| Expected | 0 | 0 | 0 |
| **Total** | **776** | **100** | **676** |

The 435 MW of Real-Time Emergency Generation (RTEG) with capacity obligations in ISO-NE's Forward Capacity Market are used for meeting the Reference Margin Level. RTEG is treated as a demand resource that can be called as part of OP 4 Action 6.

## Transmission

All significant transmission lines and transformers are expected to be in service through the 2012 summer season with the exception of scheduled transmission projects in Maine as part of the Maine Power Reliability Program (MPRP) construction. In the event of a major unplanned outage of significant transmission facilities and the scheduling of MPRP construction outages, operating procedures will be in place to maintain system reliability. As a result, there are no expected project delays or temporary service outages for ISO-NE transmission facilities that would impact reliability during the 2012 summer.

## Operations

There are no extreme conditions that are expected to adversely impact system reliability during the 2012 summer period. Therefore, no special operating studies are needed beyond the normal long- and short-term studies that are performed constantly to assess system conditions for each period during the year. Reduced and uncertain fuel supplies to Northeast Massachusetts/Boston resources will cause local capacity margins to be tight under high load conditions.

The implementation of the FCM has enhanced the integration of demand resources into system operations. ISO New England has two real-time demand resource programs that can be used to manage load and reserves as part of implementation of OP 4. The first program is focused on load response and is used early in OP 4. The second is emergency generation (RTEG), which is accessed in a later OP 4 action. All of these resources are audited in both the summer and winter period each year for their ability to perform. Based on DR audits in summer 2011 and the response of Active DR during the July 22, 2011 OP 4 event, ISO-NE expects that approximately 95 percent of DR capacity will perform. In addition, each resource submits the hourly status of their capability to the ISO, and the system operators are able to view that capability in real-time. Finally, the operators are provided with telemetry from each resource to monitor the real-time performance of the resources in relation to their capacity supply obligations.

There are no environmental or regulatory restrictions currently being discussed or forecast for the region that may significantly impact system reliability. In the past, environmental restrictions on coastal or river-based generating units due to cooling water discharge temperatures during extremely hot summer days and/or low hydrological conditions have resulted in temporary capacity reductions ranging from 50 MW to 500 MW. It is expected that such temporary reductions will be significantly reduced in the future due to the installation of closed loop cooling systems.

The regional gas pipelines and local gas distribution companies (LDCs) communicate with ISO-NE to identify any planned maintenance that may impact fuel deliveries to the power sector. ISO-NE was informed, well in advance, of a four-day, planned outage of a regional gas pipeline that is scheduled for early June. ISO-NE and the owners of the pipeline are working together to minimize the impacts from this planned outage, as well as accommodate other gas sector maintenance and inspection outages planned during the spring, summer, and fall timeframes.

Historically, fuel supply and delivery options have been readily available to generators within New England during the summer months. For the summer of 2012, ISO New England does not foresee system-wide fuel supply or delivery constraints. In the Northeast Massachusetts/Boston area, reduced and uncertain fuel supplies to Northeast Massachusetts /Boston resources will cause localized capacity margins to be tight under high load conditions. In addition, New England's dependence on natural gas to fire combined cycle generation requires close coordination with natural gas pipeline companies as well as major LNG companies as part of its communications protocol.

## Vulnerability Assessment

New England has not been undergoing a drought and drought conditions are not forecasted for the near future. Overall, no significant generating facilities are projected to be out of service during the 2012 summer peak demand period.

Since demand resources with obligations in the FCM risk being penalized for under-performance, ISO-NE anticipates that the DR response rate will be at or very close to the full capacity obligation. This has been confirmed by audits of Active DR in summer 2011, when 95 percent of DR capacity responded, as well as during the July 22, 2011 OP 4 event when approximately 100 percent of RTDR responded. This level of response may not occur during an extended period of dispatch; such a condition has not yet occurred, so there is no data on which to base assumptions.

Wind generation capacity in ISO-NE is growing, with approximately 566 MW installed and commercially operational capacity as of March 2012. This growth in wind power along with the recommendations developed during the New England Wind Integration Study (NEWIS) has led ISO-NE to plan for and implement a centralized wind power forecasting service. The Wind Power Forecast Integration Project (WPFIP) will be implemented in two phases. Phase 1 of the WPFIP, scheduled to be completed in the first quarter of 2013, focuses on setting up the communications and database systems to be able to deliver wind power forecasting related data from wind plants through ISO-NE to the wind power forecaster service and vice-versa, as well as developing situational awareness displays and functions to enhance ISO operator situational awareness for wind power, and incorporating the forecasts into the day-ahead unit commitment and periodic unit commitment refinement processes.

No special protection systems have been installed since last summer in New England. Additionally, there are no reductions or retirements scheduled within the 2012 summer period that relate to compliance with environmental regulations.

ISO-NE tracks environmental regulations and projects the impacts of potential regulations in its long-term planning studies. In the upcoming three-year period, any generator reductions or retirements would be reflected in the FCM obligations.

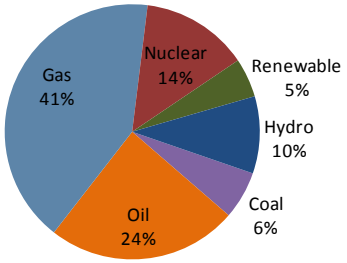
Since the FCM requires that adequate resources are purchased to meet the Installed Capacity Requirement, any capacity requirements that can potentially not be met due to long-term outages can be supplied by other FCM resources.

ISO-NE routinely gauges the impacts that fuel supply disruptions could have upon system or subregional reliability. Because natural gas is the predominant fuel used to produce electricity in New England, ISO-NE monitors the regional natural gas pipeline systems, via their electronic bulletin board postings, to ensure that emerging gas supply or delivery issues can be incorporated into the daily or next-day operating plans. Should issues arise that may impact natural gas deliveries to regional power generators, ISO-NE has communication protocols in place with the Gas Control Centers of regional pipelines and LDCs, in order to quickly understand the emerging situation and then implement mitigation measures. In the case of regional fuel supply deficiencies, ISO-NE's Operating Procedure No. 21 - Action during an Energy Emergency (OP 21) is used to facilitate communication with market participants in an attempt to bring more fuel supply to the system. Historically, fuel supply and delivery options have been readily available to generators within New England during the summer months. For the summer of 2012, ISO New England does not foresee system-wide fuel supply or delivery constraints. In the Northeast Massachusetts/Boston area, reduced and uncertain fuel supplies to Northeast Massachusetts /Boston resources will cause localized capacity margins to be tight under high load conditions. In addition, New England's dependence on natural gas to fire combined cycle generation requires close coordination with natural gas pipeline companies as well as major LNG companies as part of its communications protocol.

# NPCC-New York (NYISO)

| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 34,908 | - |
| Future-Planned | 0 | - |
| Supply-Side Demand Response | 2,165 | - |
| Net Capacity Transactions | 1951 | - |
| **Anticipated** | **39,024** | **17.21%** |
| Existing-Other and Future-Other | 0 | - |
| **Prospective** | **39,024** | **17.21%** |
| **Reference Margin Level** | - | **16.00%** |

On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **32,712** | **33,295** |
| Demand-Side Demand Response (2012) | - | 0 |
| Supply-Side Demand Response (2011) | 2,053 | - |
| **Total Internal** | **34,765** | **33,295** |

| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 32,712 | 1.8% |
| Actual Peak Demand | 33,865 | -1.7% |
| All-Time Summer Peak Demand (August 2, 2006) | 33,939 | -1.9% |

Assessment Area Boundary



*Note: Additional information regarding the methods and assumptions used in the development of the NPCC-New York (NYISO) seasonal assessment can be found in Appendix I and on the NERC website.*[86]

## Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the New York Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The reserve margins for the New York Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer season.

A total of 0 MW of capacity additions will be added during the 2012 summer. However, a total of 1,505 MW of retirements and protective layups of generation have been implemented since summer 2011. According to the NYISO's demand forecast, Total Internal Demand has increased from 32,712 MW to 33,295 MW since the 2011 summer. This equates to an annual growth rate of 1.8 percent.

## Planning Reserve Margins

The NYISO is projecting an adequate Planning Reserve Margin during the 2012 summer, as presented in Table 47. The Anticipated Reserve Margins range from 17.2 percent to 42.8 percent during the summer months. The Reference Margin Level is 16.0 percent.

The NYISO projects adequate levels of installed capacity and demand response. Unforced Forced outages could reduce available installed capacity but that is not anticipated at this time

[86] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

**Table 47: NPCC-New York (NYISO) Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 15.50% | 16.00% |
| Existing-Certain & Net Firm Transactions | 19.15% | 17.21% |
| Anticipated | 19.15% | 17.21% |
| Prospective | 19.15% | 17.21% |

The NYISO projects adequate levels of installed capacity and demand response. Forced outages could reduce available installed capacity but that is not anticipated at this time.

## Demand

The peak demand forecast for summer 2011 was 32,712 MW. The actual peak demand was 33,865 MW on July 22, 2011, hour beginning 3:00 PM. Demand response programs resulted in a load curtailment estimated to be 1,431 MW. The load without the curtailment would therefore have been 35,296 MW. Extreme weather conditions were present throughout the entire state on the day of the peak, with weather conditions exceeding the 90th percentile of typical peak-producing weather conditions. The weather adjusted load at normal weather conditions was determined to be 33,018 MW, with downward adjustment of 2,278 MW due to weather. The weather-adjusted peak load was 306 MW (0.9 percent) above the forecast. Most of this is attributed to the return to service of large industrial load due to improved economic conditions.

As presented in Table 48, the 2012 coincident peak demand forecast is 33,295 MW. The increase in the forecast since 2011 (583 MW) summer is due primarily to a return to service of large industrial loads and a gradual improvement in economic conditions throughout the state. There are no changes or enhancements to methods used in the assessment forecast since last summer.

**Table 48: NPCC-New York (NYISO) Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| Net Internal | 32,712 | 33,295 | 583 | 1.78% |
| Total Internal | 34,765 | 33,295 | -1,470 | -4.23% |

## Demand-Side Management

The total amount of Demand Response and Energy Efficiency/Conservation that is expected to be in available on peak for the 2012 summer includes Load as a Capacity resource: 2,165 MW. Additionally 257 MW of Voluntary Energy Demand Response is also projected to be available. Figure 37 and Table 49 present the demand response forecasted for the 2011 and 2012 summer peaks in the New York Assessment Area.

**Figure 37: NPCC-New York (NYISO) Demand Response**

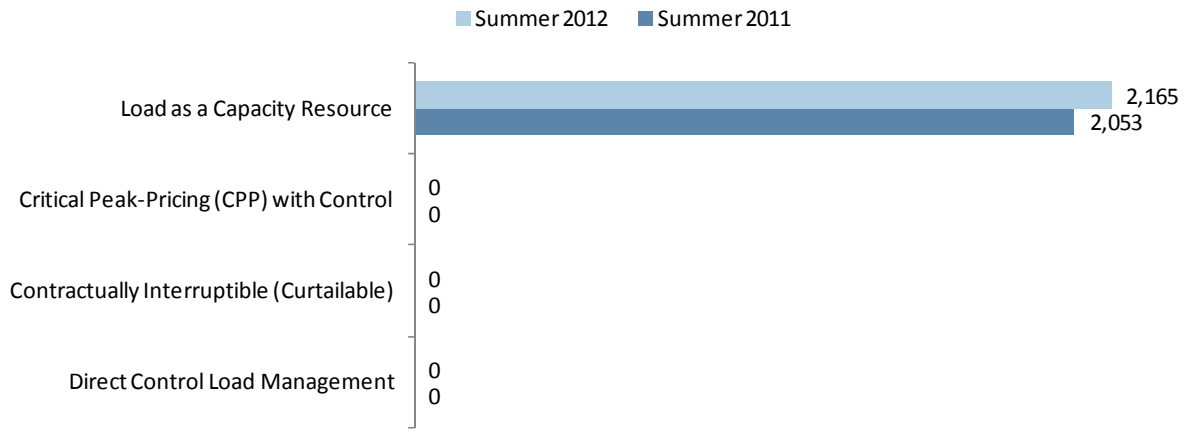



**Table 49: NPCC-New York (NYISO) Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 0 | 0 | 0 |
| Contractually Interruptible (Curtailable) | 0 | 0 | 0 |
| Critical Peak-Pricing (CPP) with Control | 0 | 0 | 0 |
| Load as a Capacity Resource | 2,053 | 0 | 2,165 |
| **Total Demand Response** | **2,053** | **0** | **2,165** |
| **Percentage of Total Internal Demand** | **5.91%** | **0.00%** | **6.50%** |

Demand response resources in the Special Case Resource (reported under Load as a Capacity Resource) and Emergency Demand Response Programs (reported as Voluntary Energy Demand Response) are deployed for forecast or actual operating reserve shortages or other emergency reliability needs.

The most recent status on existing and projected Demand-Side Management programs includes:

- Energy Efficiency/Conservation programs are currently offered throughout the state by a number of utilities and state agencies for a cross-section of market segments and energy efficiency measures.
- No changes anticipated this year for Total Dispatchable and Controllable Demand Response.
- For Demand Response used for Ancillary Services Communication improvements have been made by the NYISO, to allow direct communication of dispatch signals to Demand Response providing Ancillary Services and market rules for allowing aggregations to provide operating reserves and regulation service are expected to reduce barriers to entry.

## Generation

For the 2012 summer season the NYISO projects 34,908 MW of Existing-Certain capacity for the forecasted peak month.

Traditionally, New York generation mix has been dependent on fossil fuels for the largest portion of the installed capacity. Recent capacity additions or enhancements now available use natural gas as the primary fuel. While some existing generators in southeastern New York have “dual-fuel” capability, use

of residual or distillate oil as an alternate may be limited by environmental regulations. Adequate supplies of all fuel types are expected to be available for the summer period.

Since the 2011 summer season the New York control area has added 456 MW of dual-fuel (oil or gas) generation, 20 MW of solar generation, 13 MW of wind generation, 5 MW of landfill gas generation and 1 MW of run-of-river hydro generation that are considered Existing-Certain resources. There are no planned additions during the 2012 summer season.

There were fourteen unit retirements in New York since the 2011 summer season that will impact 2012 summer generation. Protective layups and retirements are included below:

- Astoria Units 2 and 4 (180 and 380 MW respectively);
- Gowanus Barge Units 1 and 4 (160 MW each);
- Ravenswood GT 3 and 4 (43 MW)
- Astoria GTs 10 and 11 (32 MW each)
- Barrett Unit #7 (20 MW),
- Binghamton Cogen (48 MW),
- Beebee CT 13 (18 MW),
- Far Rockaway (105 MW),
- Glenwood units 4 and 5 (114 MW each)

Total nameplate retirements amount to 1,403 MW. Since the NYISO projects adequate resources available for the 2012 summer season, no specific measures are necessary and no potential reliability issues are foreseen.

The following factors are not expected to cause any short-term impacts during the 2012 summer season: generator up-rates; units taken out of service; units being brought into service; long-term outages; behind-the-meter generation, or "non-traditional" generation. Table 50 includes resource projections for the 2011 and 2012 summers.

**Table 50: NPCC-New York (NYISO) Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 36,700 | 34,908 |
| Future-Planned | 0 | 0 |
| Supply-Side Demand Response | 2,053 | 2,165 |
| Net Capacity Transactions | 222 | 1,951 |
| **Anticipated** | **38,975** | **39,024** |
| Existing-Other and Future-Other | 0 | 0 |
| **Prospective** | **38,975** | **39,024** |

There is nameplate capacity of 1,363 MW of wind generation in the New York control area with 248.1 MW of expected on-peak capacity. There is nameplate capacity of 32 MW of solar generation in the New York control area with 20.8 MW of expected on-peak capacity. There is nameplate capacity of 4,676 MW of large hydro and 1,005 MW of run-of-river hydro generation in the New York control area with 4,582 MW and 552 MW of expected on-peak capacity, respectively. There is nameplate capacity of 432 MW of biomass generation in the New York control area with 389 MW of expected on-peak capacity.

Wind generation is derated 81.9 percent. Solar generation is derated 35 percent. Large hydro is derated 2 percent while run-of-river hydro is derated 45 percent. Landfill gas units are derated 16.6 percent while refuse and wood biomass units are derated 8.1 percent. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 38 and Table 51.

**Figure 38: NPCC-New York (NYISO) Renewable Generation**

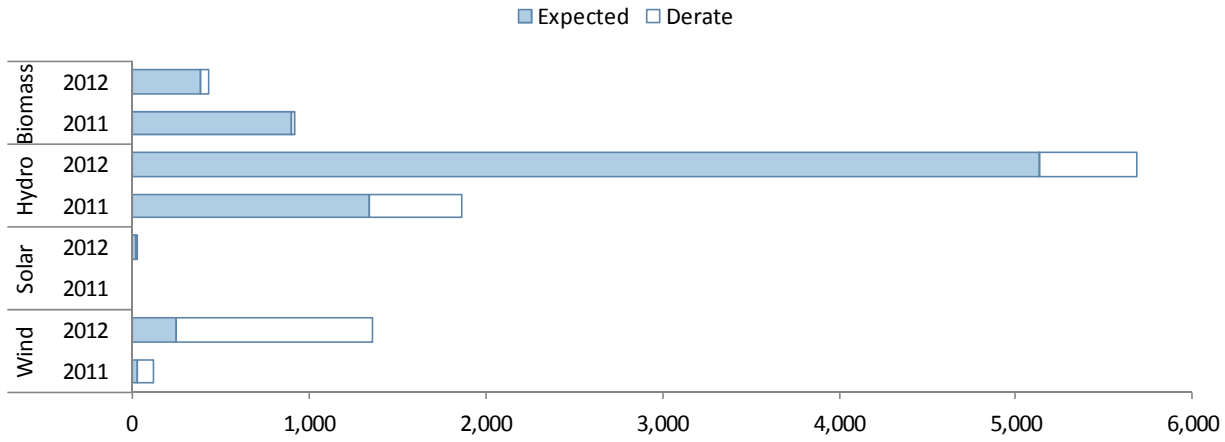



**Table 51: NPCC-New York (NYISO) Renewable Generation**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 26 | 248 | 0 | 21 | 1,346 | 5,135 | 897 | 390 |
| Derate | 93 | 1,115 | 0 | 11 | 517 | 546 | 18 | 42 |
| **Nameplate** | **119** | **1,363** | **0** | **32** | **1,863** | **5,681** | **915** | **432** |

NYISO has incorporated variable resources into the dispatch software, along with Limited Energy Storage Resources, (flywheel and batteries). These resources are integrated such that no unique operational procedures are required.

## Capacity Transactions

The NYISO projects net imports of committed external resources into the New York Balancing Authority area of 1,951 MW during summer 2012. Due to NYISO market rules the specific projected sales and purchases are considered confidential non-public information and cannot be explicitly indicated in this assessment. On-peak capacity transactions projected for the 2012 summer are included in Table 52.

**Table 52: NPCC-New York (NYISO) Capacity Transactions**

| Capacity Transactions | Imports | Exports | Net |
|---|---|---|---|
| Firm | 1,951 | 0 | 1,951 |
| Expected | 0 | 0 | 0 |
| **Total** | **1,951** | **0** | **1,951** |

Capacity purchases in New York are not required to have accompanying Firm transmission reservations, but adequate transmission rights must be available to assure delivery to New York when scheduled. External capacity is also subject to external availability rights. Availability on the import interface is offered on a first-come first-serve basis. The total capacity purchased for this summer operating period may increase since there remains both time and external rights availability.

Due to NYISO market rules, information on specific import and export transactions is considered confidential. Information on the aggregated or net expected capacity imports and exports during peak summer conditions is not yet known. Capacity is traded in the NYISO market as a monthly product, and total imports and exports are not finalized until shortly before the month begins. NYISO does not rely on external resources for emergency assistance.

### Transmission

There are no project delays or service outages that will impact reliability during the 2012 summer. The Beck-Packard BP76 230 kV circuit is expected to remain out of service through the summer period. It is not expected to have a significant impact on system reliability.

An Astoria East 345/138 kV transformer and a 138 kV phase shifter will be installed in the New York City area to assure local area reliability for the conditions of a generator retirement (Astoria 2) and simultaneous long-term forced outage of an adjacent generator proactive layup (Astoria 4).

Adjacent circuits on a common tower out of Oakdale 345 kV station will be separated to assure local area reliability to accommodate the retirement of a local generator.

The Beck-Packard 76 (BP76) 230 kV line will be out of service for the summer period. In addition the Massena-Moses 2 (MMS-2) 765/230 kV line will be out of service for the summer period.

### Operations

NYISO conducts capability assessments studies. There were no unique operational problems observed from these studies

NYISO has incorporated variable resources into the dispatch software, along with Limited Energy Storage Resources, (flywheel and batteries). These resources are integrated such that no unique operational procedures are required. NYISO does not anticipate any reliability issues from minimum demand or over generation.

The use of Demand resources are fully integrated into the policies and procedures of the NYISO. The program design promotes participation and the ISO expectation is for full participation. Further control actions are outlined in ISO policies and procedures. There are no limits to the number of times a resource can be called upon to provide response.

High capacity factors on certain New York City (NYC) peaking units could result in possible violations of their daily NOx emission limits if they were to fully respond to the NYISO dispatch signals. Significant run time on peaking units, indicating the potential for a violation, could be the result of long duration hot weather events or loss of significant generation or transmission assets in NYC. In 2001, the New York State Department of Environmental Conservation (DEC) extended the agreement it had previously with the New York Power Pool to address the potential violation of NOx and opacity regulations if the NYISO were required to keep these peaking units operating to avoid the loss of load. Pursuant to the terms of this agreement (DEC, Declaratory Order # 19-12) if the NYISO were to issue an instruction to a Generator to go to maximum capability, in order to avoid loss of load, any violations of NOx RACT emission limits or opacity requirements imposed under DEC regulations would be subject to the affirmative defense for emergency conditions. This determination is limited to circumstances where the maximum capability requested by the NYISO would involve the generation of the highest level of electrical power achievable by the subject Generators with the continued use of properly maintained and operating pollution

control equipment required by all applicable air pollution control requirements At this time NYISO does not anticipate any unusual conditions that will impact reliability

## Vulnerability Assessment

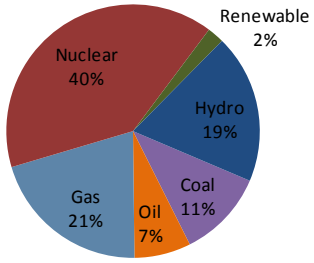
For 2012 summer there are no specific operational concerns for extended drought conditions, long-term generator outages, unavailable demand response or increases in variable generation. Also, there are no anticipated impacts from environmental regulations this season. No special protection systems have been installed on the New York system since last summer.

NYISO has adopted the New York State Gas-Electric Coordination Protocol as Appendix BB to its Open Access Transmission Tariff (OATT). This Coordination Protocol applies to circumstances in which the NYISO has determined (for the bulk power system) or a Transmission Owner has determined (for the local power system) that the loss of a Generator due to a Gas System Event would likely lead to the loss of Firm load. This Coordination Protocol also applies to communications following the declaration of an Operational Flow Order or an Emergency Energy Alert (EEA). There are no anticipated fuel delivery problems for this summer operating period.

# NPCC-Ontario (IESO)

| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 27,955 | - |
| Future-Planned | 1,170 | - |
| Supply-Side Demand Response | 1,326 | - |
| Net Capacity Transactions | 0 | - |
| **Anticipated** | **30,451** | **30.08%** |
| Existing-Other and Future-Other | 6,284 | - |
| **Prospective** | **36,735** | **56.92%** |
| **Reference Margin Level** | - | **20.40%** |

On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **23,561** | **23,409** |
| Demand-Side Demand Response (2012) | - | 0 |
| Supply-Side Demand Response (2011) | 1,235 | - |
| **Total Internal** | **24,796** | **23,409** |

| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 23,561 | -0.65% |
| Actual Peak Demand | 25,450 | -8.02% |
| All-Time Summer Peak Demand (August 1, 2006) | 27,005 | -13.32% |

Assessment Area Boundary



*Note: Additional information regarding the methods and assumptions used in the development of the NPCC-Ontario (IESO) seasonal assessment can be found in Appendix I and on the NERC website.*[87]

## Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for assessing the reliability of resources, demand, and transmission infrastructure in the Ontario Assessment Area. Generation data was collected from individual entities and aggregated using a bottom-up approach. Demand data projections were based on economic indicators, long-term weather forecasts, and historic load data, using a top to bottom approach.

The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer. A total of 1,357 MW of nameplate capacity will be added before and during the 2012 summer. According to the Ontario demand forecast, Total Internal Demand is expected to decrease from 23,501 MW (weather-corrected actual demand) to 23,409 MW since the 2011 summer. This equates to an annual growth rate of -0.4 percent.

## Planning Reserve Margins

Ontario is projecting adequate Planning Reserve Margins during the 2012 summer. Anticipated Planning Reserves, determined on the basis of the IESO's requirements for Ontario self-sufficiency, are above the Reference Margin Level over this period (for normal weather conditions). The Reference Margin Level for Ontario is 20.4 percent. Table 53 includes the 2011 and 2012 reserve margins for the Ontario Assessment Area.

[87] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

**Table 53: NPCC-Ontario (IESO) Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 21.30% | 20.40% |
| Existing-Certain & Net Firm Transactions | 31.75% | 25.08% |
| Anticipated | 31.80% | 30.08% |
| Prospective | 37.37% | 56.92% |

During the summer of 2012, there will be more than 1,350 MW of capacity added to the grid, comprising of one refurbished nuclear unit, with a capacity of 750 MW returning to service, approximately 400 MW of new gas-fired generation and more than 200 MW of new grid-connected renewable generation. Many of these projects have started their commissioning or at an advanced construction stage. Though some delays in Future-Planned capacity are still possible, Ontario meets the Reference Margin Level, with Existing-Certain capacity.

The IESO prepares for extreme weather conditions during the summer by executing planning studies that use the most severe weather experienced since 1970. These studies show that Ontario will have sufficient reserves throughout the entire 2012 summer period. Available operational and market measures, as well as interconnection capabilities are considered sufficient to meet the peak demands during the 2012 summer.

## Demand

Last summer's peak demand forecast was 23,561 MW (weather-normalized) and 25,941 MW (extreme weather). The actual (non-weather-corrected) peak demand was 25,450 MW. Demand was significantly higher than the weather-normalized forecast, with actual conditions meeting those of the IESO extreme weather scenario. Once the impact of demand response is considered, the "reconstituted" peak would have been 25,858 MW. This would mean the extreme weather forecast had a mean absolute percentage error of 0.3 percent, compared to the reconstituted demand.

The 2012 summer peak demand forecast is 23,409 MW, which is lower than the peak demand forecast for the summer of 2011. Peak demand is expected to be lower due to three main factors:

- The economy remains stagnant with little growth in the industrial sector;
- Residential and commercial load will increase due additional construction activity;
- Underlying load growth will be more than offset by the increase in embedded generation, conservation and customers facing time-of-use rates.

Table 54 includes the demand forecasts for the 2011 and 2012 summers for the Ontario Assessment Area.

**Table 54: NPCC-Ontario (IESO) Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| Net Internal | 23,561 | 23,409 | -152 | -0.65% |
| Total Internal | 23,561 | 23,409 | -152 | -0.65% |

The economic outlook for Canada calls for modest growth throughout 2012. Ontario is expected to lag behind national growth as its export-oriented manufacturing sector is highly dependent on U.S. and global growth. While other oil producing provinces will lead the nation in growth, Ontario will be

impacted by the upward pressure that oil exports put on the Canadian dollar. Accordingly, the economic outlook varies according to the economic characteristics throughout the province – and throughout Canada. Areas that rely on the forestry industry have been negatively impacted by the high Canadian dollar and subsequent lower demand for paper products. Those areas with a large manufacturing concentration have stabilized, but have not returned to the prerecession growth levels.

On a positive note, the mining and petrochemical sectors have remained strong, as foreign demand has remained untarnished. Economic conditions in Toronto are also expected to improve, due to its diverse economy and dominance as the nation's largest city.

Economic growth is not directly aligned with electricity growth, due to structural changes in the Ontario economy. Many of the growth areas in the economy are in the service sector, which does not typically consume large volumes of electricity. In addition, demand from the traditional energy-intensive resource and manufacturing sectors is expected to remain unaffected.

## Demand-Side Management

The IESO has just over 1,850 MW of demand response capacity of which 1,326 MW is deemed to be reliably available at the time of system peak. Figure 39 and Table 55 present the demand response forecasted for the 2011 and 2012 summer peaks in the Ontario Assessment Area.

There are limited restrictions on how many times Demand Response can be deployed, as there are price and demand triggers that must both be met to deploy these resources. These triggers are calculated in advance to meet a certain number of activations per month.

**Figure 39: NPCC-Ontario (IESO) Demand Response**

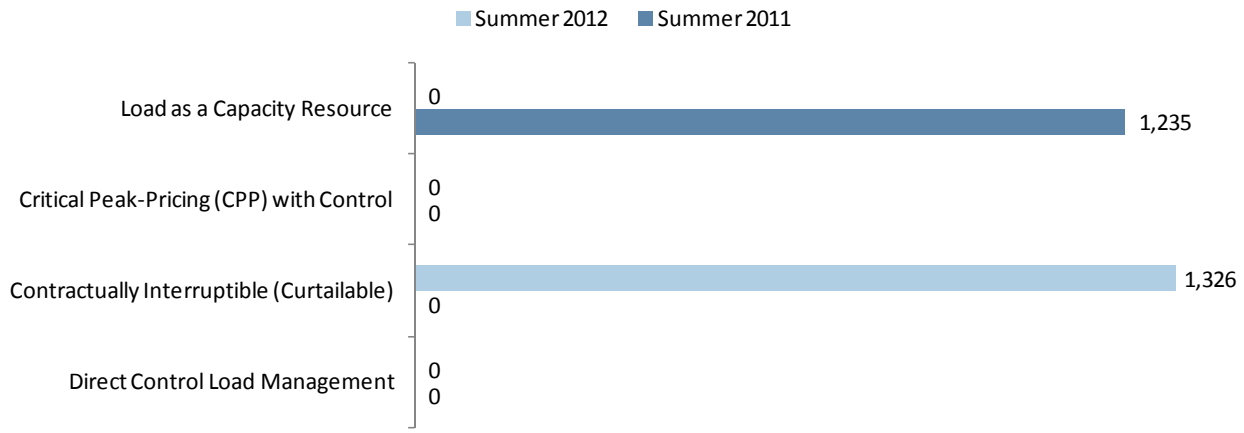



**Table 55: NPCC-Ontario (IESO) Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 0 | 0 | 0 |
| Contractually Interruptible (Curtailable) | 0 | 0 | 1,326 |
| Critical Peak-Pricing (CPP) with Control | 0 | 0 | 0 |
| Load as a Capacity Resource | 1,235 | 0 | 0 |
| **Total Demand Response** | **1,235** | **0** | **1,326** |
| **Percentage of Total Internal Demand** | **5.24%** | **0.00%** | **5.66%** |

The majority of Ontario's demand response programs are dispatchable, market driven programs. The two main initiatives are Dispatchable Loads and Demand Response 3 (DR3). The Dispatchable Loads bid into the market and are dispatched off like any resource. This program has a total capacity of roughly 900 MW. The DR3 program contracts loads that are dispatched off the system based on the supply cushion – the difference between demand and supply. This program has a capacity of 525 MW. Four other programs provide an additional 425 MW of capacity; none of the IESO's demand response programs are used for Ancillary Services.

There are a number of conservation initiatives under development by distributors and the Ontario Power Authority, which are decremented from demand. However, none of these are included as demand response programs.

## Generation

The amount of Existing-Certain and Existing-Other on-peak resources is 27,955 MW and 6,284 MW, respectively. Existing-Inoperable totals 27.5 MW. The primary fuel of existing resources by installed capacity is nuclear (34 percent), followed by gas/oil (28 percent) and hydroelectric (23 percent). 13 MW of Existing-Certain wind generation has been added since the prior season. Table 56 includes projections of Ontario resources for the 2011 and 2012 summer.

**Table 56: NPCC-Ontario (IESO) Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 29,807 | 27,955 |
| Future-Planned | 12 | 1,170 |
| Supply-Side Demand Response | 1,235 | 1,326 |
| Net Capacity Transactions | 0 | 0 |
| **Anticipated** | **31,054** | **30,451** |
| Existing-Other and Future-Other | 1,312 | 6,284 |
| **Prospective** | **32,366** | **36,735** |

Leading up to the 2012 summer season, Ontario projects the addition of two wind farms (214 MW) and one new gas-fired generator (393 MW). A nuclear unit refurbishment (Bruce G1 750 MW) is expected to be completed during the summer period, adding an additional 750 MW of capacity. These projects will provide an additional nameplate capacity of 1,357 MW, of which 1,170 MW is projected to be available during the summer peak.

In December 2011, the shutdown of two southern Ontario coal units resulted in a decrease of 980 MW in Existing-Certain capacity since last season. To compensate for the reactive output that was lost with the closure of these units, dynamic control facilities at Detweiler and Nanticoke transformer stations were placed in service. Since the last seasonal assessment (Winter 2011/2012), a 99 MW wind farm has come in to service.

Since the summer of 2011 and prior to the summer of 2012, 600 MW of new embedded generation contracted to begin commercial operation. The Ontario Power Authority (OPA) provides the IESO with information for embedded generation. Based on the fuel type, a production estimate is generated and applied in the form of a demand reduction starting on the in service date specified in the contract.

A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 40 and Table 57.

**Figure 40: NPCC-Ontario (IESO) Renewable Generation**

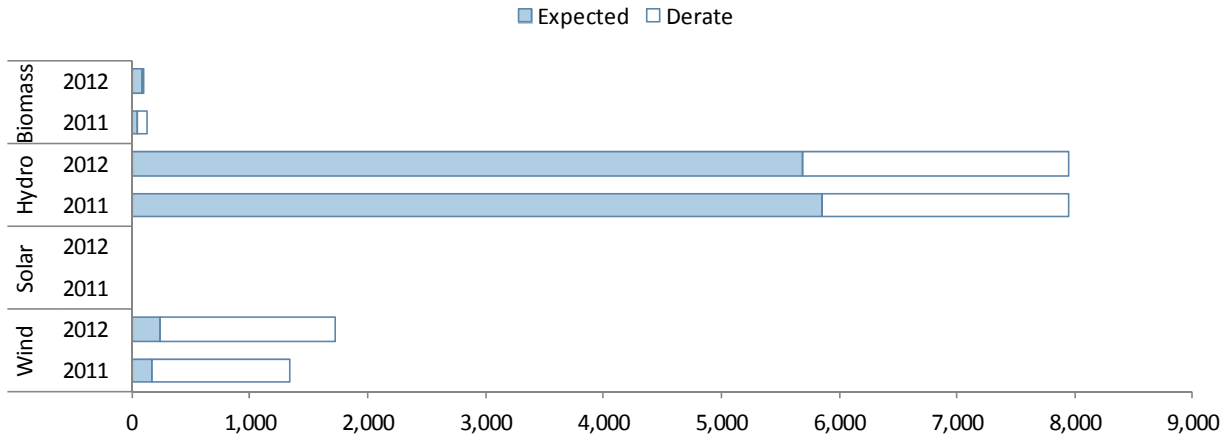



**Table 57: NPCC-Ontario (IESO) Renewable Generation**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 173 | 230 | 0 | 0 | 5,852 | 5,694 | 37 | 81 |
| Derate | 1,160 | 1,496 | 0 | 0 | 2,095 | 2,253 | 85 | 13 |
| **Nameplate** | **1,334** | **1,725** | **0** | **0** | **7,947** | **7,947** | **122** | **95** |

To model wind resources in the adequacy assessments, the IESO uses an estimated wind capacity contribution during peak demand hours. This model captures wind output during the top five contiguous daily peak demand hours for the winter and summer seasons, as well as monthly shoulder periods. Two sets of wind data are considered: simulated wind data over a fixed 10-year history, and actual wind farm output data collected since March 2006. A conservative approach is employed, which selects the lesser value of the two data sets (simulated vs. actual) for each winter/summer season and shoulder period month. For the seasonal assessments, wind capacity contribution is represented deterministically, by selecting median values observed during the winter and summer seasons and shoulder period months.

IESO resource adequacy assessments include hydroelectric generation capacity contributions based on median historical values of hydroelectric production plus operating reserve provided during weekday peak demand hours. Hydroelectric production is monitored on a monthly basis and due allowance is made for deviations from the median historical conditions. Deviations from the median are not anticipated at this time for the upcoming summer. In the operating timeframe, water resources are managed by market participants through market offers to meet the hourly demands of the day. Since most hydro storage facilities are energy limited, hydroelectric operators identify weekly and daily limitations for near-term planning in advance of real-time operations.

The forecast of hydro generation was enhanced in November 2011 to account for the impact of project related long-duration outages (*e.g.* hydro facility expansions and major equipment replacements and/or repairs) that occur less frequently – but take longer – than regular maintenance. The hydroelectric performance is monitored on a monthly basis and adjustments may also be made to the forecast values when water conditions drive expectations of higher or lower output that deviates from median values by approximately 500 MW for two consecutive months.

The Stakeholder Engagement (SE) 91 process is currently underway to address the need for forecasting, visibility and dispatch of renewable resources. The results are expected after the summer season.

## Capacity Transactions

In its determination of resource adequacy, the IESO plans for Ontario to meet NPCC Regional criteria without reliance on external resources. There are no Firm or Expected imports or exports identified for the 2021 summer.

For use during daily operation, operating agreements between the IESO and neighboring jurisdictions in NPCC, RFC and MRO include contractual provisions for emergency imports directly by the IESO. IESO also participates in a shared activation of reserve group which includes PJM, NYISO, ISO-NE and New Brunswick. No emergency generation is assumed to be available to meet Ontario's Reference Margin Level.

## Transmission

Planned outages may result in some transfer capability reductions of the transmission circuits but are not expected to have any impact on the load supply. The completion date for transmission reinforcements from the Niagara region into the Hamilton-Burlington area continues to be delayed. This delay could impact the ability to import at Niagara during periods of high Ontario generation in the Niagara area, particularly during high demand period and during outage conditions. Under the conditions expected for this summer, studies show that the system is adequate to meet expected demands without this reinforcement.

The failed R76 voltage regulator and the BP76 circuit on the Niagara intertie will not be available for summer. A bypass will remain available for use, if required, until the R76 voltage regulator returns.

Phase angle regulators (PAR) are installed on the Ontario-Michigan interconnection at Lambton TS on the Ontario side and at Bunce Creek TS in Michigan, representing three of the four interconnections within Michigan. Final regulatory approvals have been received, permitting operation of these facilities. Two of three PARs began operation in April 2012 to help manage circulation power flows around Lake Erie, as well as contingencies. The operation of these PARs along with the PAR on the Ontario-Michigan interconnection (near Windsor) will control flows to a limited extent, and assist in the management of system congestion.

The necessary approvals for modifications to the existing Bruce Special Protection System (SPS) are in place to accommodate the full output of both new and existing generation in the Bruce area.

To prevent low voltage conditions on the 115 kV transmission system in the Woodstock area during summer extreme weather conditions, Hydro One is planning to add a new transformer station and a second supply point by extending the 230 kV transmission lines from Ingersoll to the Woodstock area and installing a new 230/115 kV transformer station. These plans will provide additional reliability if load growth continues in the area.

## Operations

As part of the IESO-conducted analysis, an extreme weather scenario is used to assess the system under stressed conditions. An extreme weather scenario is generated by taking the most severe weather since 1970 on a week by week basis. This gives an "outer envelope" of the conditions that the system may

face through the upcoming season. There are no new operating procedures resulting from integration of variable resources.

Additions of base load generation from nuclear and renewable sources combined with declining off-peak demands are expected to increase the frequency and magnitude of surplus generation events beginning in the spring of 2012 and persisting throughout the summer. The IESO does not anticipate any reliability concerns resulting from minimum demand and surplus generation.

A lack of direct control over a number of factors that contribute to surplus generation, such as weather, consumption and market behavior, poses operational challenges in managing surplus conditions. The need for maximum flexibility from all resources is integral to the efficient and reliable operation of the IESO grid.

With a forecasted increase in surplus generation, it is expected that some out of market control actions will be required to manage the surplus. These actions will extend beyond typical market actions, which include exports, minimum economic hydro dispatch and nuclear maneuvers. The IESO will continue to examine and pursue the ability to dispatch base load resources to manage these conditions. Finally, environmental and/or regulatory restrictions are not expected to impact reliability this summer

### Vulnerability Assessment

Ontario generates its forecasts using median conditions for hydroelectric generation and does not expect any impacts from drought for summer 2012.

The IESO includes a quantity of demand response termed the “Reliably Available Capacity” in its reliability analysis. This does not represent the total registered capacity of demand response programs. For market-based programs, the IESO uses historical information to ascertain the amount of demand response capacity that is typically bid into the market at the time of the weekly peak demand. For programs that have contracts, the IESO uses both historical information and contract information in order to determine the quantity of Reliably Available Capacity.

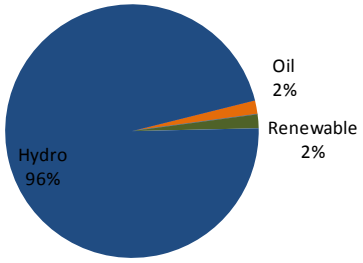
There are no significant planned long-term outage conditions expected over the summer season. Planned increases in variable generation do not present any resource adequacy or operational concerns over the summer season. Modifications to the existing Bruce special protection system are anticipated to accommodate new generation capacity from refurbishments at the relevant nuclear generating station and new wind power.

Generator owners and operators are required to keep sufficient supplies of fuel (*e.g.*, coal, nuclear fuel bundles, etc.). Coal inventories at the coal-fired plants are being carefully managed through 2014, when all coal generation has been legislated to be phased-out. There are communication protocols in effect between the IESO and gas pipeline operators to manage and share information under tight supply conditions in either sector (gas or electricity).

# NPCC-Québec

| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 33,857 | - |
| Future-Planned | 50 | - |
| Supply-Side Demand Response | 0 | - |
| Net Capacity Transactions | -1551 | - |
| **Anticipated** | **32,356** | **54.16%** |
| Existing-Other and Future-Other | 0 | - |
| **Prospective** | **32,356** | **54.16%** |
| **Reference Margin Level** | - | **10.00%** |

On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **21,283** | **20,988** |
| Demand-Side Demand Response (2012) | - | 0 |
| Supply-Side Demand Response (2011) | 0 | - |
| **Total Internal** | **21,283** | **20,988** |

| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 21,283 | -1.39% |
| Actual Peak Demand | 21,354 | -1.71% |
| All-Time Summer Peak Demand (July 8, 2010) | 22,092 | -5.00% |

Assessment Area Boundary



*Note: Additional information regarding the methods and assumptions used in the development of the NPCC- Québec seasonal assessment can be found in Appendix I and on the NERC website.*[88]

## Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the Québec Assessment Area. Data was collected from Hydro-Québec's three divisions responsible for resource and transmission adequacy. Projections are based on economic indicators, long-term weather forecasts, historic load data, generation and transmission data, as well as transactions with neighboring systems and areas.

The reserve margins for the Québec Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain well above the Reference Margin Level during the 2012 summer season. This is because the assessment area is winter-peaking and summer peak loads are typically about 58 percent of winter peak loads. Summer is therefore the preferred time for generator and transmission maintenance. Even with an appreciable amount of maintenance going on, the area still has enough margin to account for summer demand forecast uncertainty, Firm capacity transactions and other short term exports such as may be required by neighboring NPCC areas during their peak demand periods.

Capacity in the Area has actually gone down slightly from the last summer period. The Tracy oil-fired generation station (450 MW) has now been completely retired by Hydro-Québec Production (HQP) and minor hydro adjustments have also been made. On the other hand, 23 MW of small hydro are now in service along with four new wind generating stations (398 MW). Additionally, one wind G.S. (80 MW) is

[88] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

projected to be in service in June and one unit at La Sarcelle hydro G.S. (50 MW) will be placed online in July. Total Internal Capacity in August 2012 will be 42,888 MW.

According to Québec's demand forecast, Total Internal Demand has decreased slightly from 21,283 MW to 20,988 MW since the 2011 summer. This slight 1.4 percent decrease is mainly due to a slower anticipated economic growth than what was forecasted last year.

## Planning Reserve Margins

The Québec Assessment Area (the Québec Area) is projecting a Planning Reserve Margin well above its target level during the 2012 Summer Operating Period.

Because the Québec Area is winter-peaking, the Reference Margin Level is calculated for winter periods and is evaluated at about 10 percent. Assumptions used to establish reserve margin criteria, target margin levels and resource adequacy levels, and results thereof, are discussed in the last 2011 Québec Area Comprehensive Review of Resource Adequacy (Approved by the Reliability Coordinating Committee of NPCC on November 29, 2011). The assessment can be found on the NPCC's website. For this summer assessment, the Reference Margin Level is set at 10 percent.

The Québec Area is projecting an adequate Planning Reserve Margin throughout the summer season. The all-time internal peak hourly demand is 37,717 MW set on January 24, 2011. A large amount of space heating load is present during Winter Operating Periods. Summer peak demands are of the order of 22,000 MW (about 58 percent of peak winter demand). Summer Operating Periods are usually characterized by extensive generator and transmission maintenance in preparation for the upcoming winter. This explains the high level of resource adequacy characteristic of summer periods in Québec.

Both Anticipated Reserve and Prospective Margins in the Québec Assessment Area are 54.16 percent for the 2012 summer. Because these Planning Reserve Margins are significantly above the Reference Margin Level, no particular issues or circumstances have been identified that would impact reliability during the 2012 summer. Table 58 includes the 2011 and 2012 reserve margins for the Québec Assessment Area.

**Table 58: NPCC-Québec Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 10.00% | 10.00% |
| Existing-Certain & Net Firm Transactions | 40.89% | 55.24% |
| Anticipated | 42.28% | 54.16% |
| Prospective | 42.80% | 54.16% |

## Demand

Table 59 compares 2011 and 2012 summer demand forecasts.

**Table 59: NPCC-Québec Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| Net Internal | 21,283 | 20,988 | -295 | -1.39% |
| Total Internal | 21,283 | 20,988 | -295 | -1.39% |

The 2012 summer demand forecast is slightly lower than the 2011 forecast (around 1.4 percent lower). This is mainly due to slower economic growth anticipated for 2012 (compared to the 2011 economic growth forecast).

The summer 2011 forecast was 21,283 MW, while the actual peak demand occurred on July 21, at 21,356 MW (due to above-normal temperatures). The difference between the August 2011 forecasted and the actual July 2011 summer peak is not significant (73 MW).

The methods used in the assessment demand forecast have not changed from previous year and there have been footprint changes or entity acquisitions or exits.

## Demand-Side Management

Demand response programs are not required or available during summer operating periods in Québec. However, Energy Efficiency (EE) programs are implemented throughout the year and the total amount of EE associated with existing and projected programs is estimated to be equivalent to approximately 900 MW for the 2012 summer peak. EE programs and general energy saving trends are accounted for in the demand forecast.

Hydro-Québec Distribution (HQD) presents its EE plan update, titled: "Plan global en efficacité énergétique" to the Québec Energy Board (the regulatory body in Québec) for the upcoming years. This plan focuses on energy conservation measures and includes programs tailored to residential customers, commercial and institutional markets, small and medium industrial customers, and large-power customers. Examples of programs and tools for promoting energy savings for the residential customers include old refrigerator recycling, electronic thermostats, low-energy lighting, etc.[89] The provincial government, through its Ministry of Natural Resources, also implements EE programs.

## Generation

Approximately 97 percent of the Existing-Certain capacity is made up of hydroelectric resources, with the remaining 3 percent consisting of nuclear, gas-fired turbines and biomass generation. Thermal generation totals 1,898 MW of which 675 MW is nuclear generation, 507 MW is combined-cycle natural gas generation (mothballed for 2012), and 716 MW is gas-fired generation (280 MW from La Citière G.S. are also mothballed).

The only variable resources currently integrated in the Québec Assessment Area is wind. Nameplate capacity is now evaluated at 1,057 MW and continued growth is expected. On-peak wind capacity is entirely derated throughout the 2012 summer.

The amount of Existing-Certain, Existing-Other and Future-Planned and Future-Other capacity resources in service or expected to be in service are provided in Table 60.The Future-Planned line represents the coming on-line of 50 MW from La Sarcelle hydroelectric generating station unit on the James Bay system in July. Previously, in June, 80 MW of wind power generation will have been brought into service.

[89] Program characteristics can be found on Hydro-Québec's website: http://www.hydroquebec.com/energywise/index.html.

**Table 60: NPCC-Québec Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 31,396 | 33,857 |
| Future-Planned | 768 | 50 |
| Supply-Side Demand Response | 0 | 0 |
| Net Capacity Transactions | -1,411 | -1,551 |
| **Anticipated** | **30,753** | **32,356** |
| Existing-Other and Future-Other | 1,312 | 0 |
| **Prospective** | **32,065** | **32,356** |

When compared to NERC's *2011 Summer Reliability Assessment*, some resources changes have occurred for the 2012 summer period. The Tracy oil-fired generation station (450 MW) has now been retired by HQP. 23 MW of small hydro plants that are under contract with HQD are now in-service and other minor hydro adjustments have been made. Accordingly, no fuel issues or other conditions that would result in capacity reductions are expected for the 2012 summer period.

The Québec Assessment Area's renewable resource portfolio includes hydro, wind and biomass (by order of total capacity). There are no solar resources in the Québec Assessment Area.

Biomass and wind resources are owned by Independent Power Producers (IPPs). These IPPs have signed contractual agreements with Hydro-Québec. For biomass, maximum capacity and expected on-peak capacity are equal to contractual values. Wind resources maximum capacity is also equal to contractual capacity. Since the Québec Assessment Area is winter-peaking, HQD has evaluated wind resource expected capacity for the winter operating season only. The summer wind capacity expected on-peak entirely derated during the 2012 summer operating period. Figure 41 and Table 61 present the renewable resource portfolio for the 2011 and 2012 summer peaks in the Québec Assessment Area.

**Figure 41: NPCC-Québec Renewable Resources**

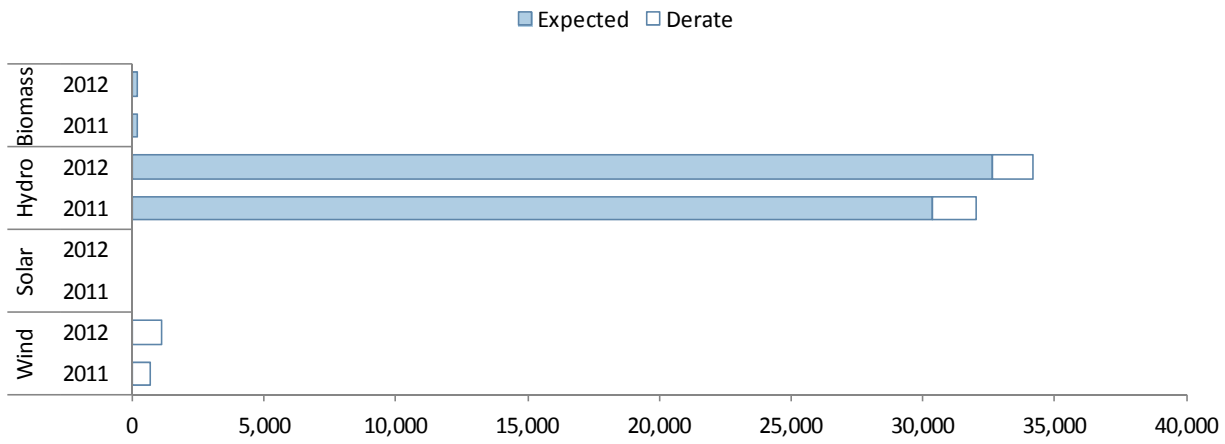



**Table 61: NPCC-Québec Renewable Resources**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 0 | 0 | 0 | 0 | 30,366 | 32,628 | 164 | 175 |
| Derate | 659 | 1,137 | 0 | 0 | 1,642 | 1,565 | 0 | 0 |
| **Nameplate** | **659** | **1,137** | **0** | **0** | **32,008** | **34,193** | **164** | **175** |

## Capacity Transactions

The Québec Area has not forecasted any imports during the 2012 summer and does not rely on any emergency imports to meet its Reference Margin Level. However, projected exports to neighboring areas total 1,551 MW, of which 1,275 MW are Firm, with the remaining 276 MW categorized as Expected. The breakdown is as shown and in Table 62:

- 896 MW to New York (620 MW are considered Firm)
- 510 MW to New England
- 145 MW to Ontario (Cornwall)

**Table 62: NPCC-Québec Capacity Transactions**

| Capacity Transactions | Imports | Exports | Net |
|---|---|---|---|
| Firm | 0 | 1,275 | -1,275 |
| Expected | 0 | 276 | -276 |
| **Total** | **0** | **1,551** | **-1,551** |

Under emergency conditions, especially during the winter, the Québec Assessment Area can rely on imports from Ontario (IESO), New York (NYISO), and the Maritimes Assessment Area. Capabilities vary with system conditions. TransÉnergie, the Transmission Operator, has agreements with all neighboring NPCC subregions that detail conditions and procedures for exchanging emergency energy. A procedure supervises Control Centre actions and communications for this energy exchange. Overall, no reliability concerns have been identified in the Québec Assessment Area for the 2012 summer.

## Transmission

Transmission project commissioning is usually scheduled during fall, in preparation for the upcoming winter peak period. No specific projects are needed to maintain or enhance reliability during the 2012 summer. As a corollary, no project delays or temporary service outages for transmission facilities are expected that would impact reliability during the 2012 summer.

A majority of the maintenance on transmission lines, transformers and generating units is performed during the summer period. Resource availability is not a problem during summer, even though exports to summer peaking NPCC subregions are sustained during peak hours. Available resources for exports actually often exceed actual summer transfer capabilities to neighboring NPCC systems.

The following three major transmission projects (originally mentioned in the NERC *2011/2012 Winter Reliability*) have been commissioned and placed in-service since prior to the 2012 summer: two -300/+300 Mvar Static Var Compensators (SVCs) at the Chénier 735/315 kV substation; a 735-kV series compensation project at Jacques-Cartier substation (on two lines near Québec City); and a 345-Mvar, 315-kV shunt capacitor bank in the Montréal area.

## Operations

TransÉnergie's significant operating studies are typically performed for the winter season, where weather conditions contribute to higher demand levels. Readers may refer to the earlier seasonal assessments for details.[90]

[90] http://www.nerc.com/page.php?cid=4|61.

Hydro-Québec participates in NPCC's seasonal CO-12 (Operations Planning) and CP-8 (Multi-Area Probabilistic Assessment) Working Group assessments of system reliability.[91] All operational planning studies are done in compliance with NPCC and NERC planning standards. These include planning studies for the bulk power system, generation integration studies, NPCC reviews, transfer limit studies, etc. The latest NPCC Comprehensive Review of the Québec transmission system for 2011-2012 was completed in May 2008. The last Interim Review of the Québec transmission system for 2016 was completed in November 2011. No particular operational problems have been observed for the oncoming 2012 summer operating period.

Currently, wind generation variability has not significantly impacted the system's day-to-day operation and the present level of wind generation does not necessitate particular operating procedures. However, data acquisition for different wind generation variables constitute valuable information for system management and wind generation forecasting is used in the subregion's system forecasting software. Long-term foreseeable impacts on system management will be addressed as necessary:

- Wind generation variability on system load and interconnection ramping.
- Frequency and voltage regulation problems.
- Increase of start-ups and/or shutdowns of hydro units due to load following coupled with wind variability. Generally units must be operated within certain limits to ensure efficiency.
- Reduction of low load operation flexibility due to low inertial response of wind generation coupled to must-run hydro generation.

No reliability concerns resulting from minimum demand and over generation are anticipated. There is hydroelectric must-run generation on run-of-the-river installations but this is small relative to system size. Moreover, as mentioned before, most generator maintenance is done during the summer, while reservoirs are allowed to fill up. A relatively high export level is usually maintained to neighboring summer peaking areas. No other unusual operating conditions are anticipated for the upcoming summer.

## Vulnerability Assessment

Given the importance of hydroelectric resources, the Québec Area has developed an energy criterion to assess its energy reliability, stating that sufficient resources should be available to go through sequences of two or four consecutive years of low water inflows totaling 64 TWh and 98 TWh, respectively, and having a 2 percent probability of occurrence. These assessments are presented three times a year to the Québec Energy Board. Normal hydro conditions are projected for 2012 summer and reservoir levels are sufficient to meet both peak demand and daily energy demand throughout the summer.

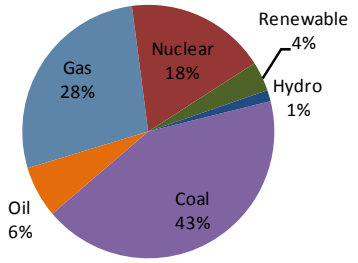
There are no significant long-term generator outages for this assessment period nor any pending future environmental regulations that may have an impact in the Québec Area for the upcoming season.

[91] https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx.

# PJM

| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 185,424 | - |
| Future-Planned | 0 | - |
| Supply-Side Demand Response | 0 | - |
| Net Capacity Transactions | 217 | - |
| **Anticipated** | **185,641** | **30.61%** |
| Existing-Other and Future-Other | 0 | - |
| **Prospective** | **190,471** | **34.01%** |
| **Reference Margin Level** | - | **15.60%** |

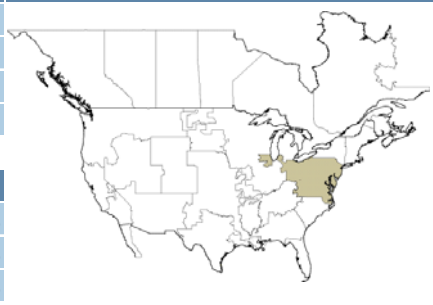
On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **137,341** | **142,135** |
| Demand-Side Demand Response (2012) | - | 11,647 |
| Supply-Side Demand Response (2011) | 11,600 | - |
| **Total Internal** | **148,941** | **153,782** |

| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 137,341 | 3.49% |
| Actual Peak Demand | 158,043 | -10.07% |
| All-Time Summer Peak Demand (July 21, 2011) | 158,043 | -10.07% |

Assessment Area Boundary



*Note: Additional information regarding the methods and assumptions used in the development of the PJM seasonal assessment can be found in Appendix I and on the NERC website.*[92]

## Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the PJM RTO Assessment Area. Data is based on economic indicators, long-term weather forecasts, and historic load data.

This year's report includes the load and resources of Duke Energy Ohio/Kentucky (DEOK), which was integrated into the PJM RTO on January 1, 2012.

The reserve margins for the PJM RTO Assessment Area are based on Anticipated resources. The Anticipated Reserve Margin will remain above the PJM Reference Margin Level during 2012 summer.

A total of 5,007 MW of capacity have been added since the 2011 summer. According to the PJM's demand forecast, Total Internal Demand has decreased from 154,383 MW[93] to 153,782 MW since the 2011 summer. This equates to an annual growth rate of -0.4 percent.

## Planning Reserve Margins

PJM is projecting an adequate reserve margin for the 2012 summer peak of 30.6 percent. The reserve margin calculation includes forecasted load, Existing-Certain generating resources, forecasted Demand-Side Management (economic DSM treated as a resource and emergency DSM treated as a load reducer), net transfers and Energy Efficiency treated as a resource. The PJM RTO Reserve Requirement is 15.6

[92] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

[93] Adjusted for the integration of Duke Energy/Kentucky (DEOK). The forecast in the *2011 Summer Reliability Assessment* was 148,941 MW.

percent for the 2012 and 2013 planning period.[94,95] Table 63 includes the 2011 and 2012 reserve margins for the PJM Assessment Area.

**Table 63: PJM Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 15.00% | 15.60% |
| Existing-Certain & Net Firm Transactions | 29.76% | 30.61% |
| Anticipated | 29.76% | 30.61% |
| Prospective | 29.76% | 34.01% |

The Reliability Pricing Model (RPM) or Forward Capacity Market provides:

- Procurement of capacity through a competitive auction three years before it is needed;
- Locational pricing for capacity that reflects limitations on the transmission system's ability to deliver electricity into an area and determine capacity needs throughout PJM;
- A variable resource requirement to help set the price for capacity;
- A backstop mechanism to ensure the availability of sufficient resources to preserve system reliability.

PJM will have an adequate reserve margin throughout the 2012 summer. The difference between the PJM RTO reserve margin and the PJM RTO Reference Margin is 15.6 percent (amounting to over 21,000 MW). The highly unlikely loss of this amount of generation due to retirements or forced outages would task the PJM operators to find replacement resources. An extremely hot and humid summer could push load up but the probability of this occurring has been included in PJM's Reserve Requirement studies.

## Demand

The PJM RTO 2011 summer peak was 163,762 MW, which occurred on July 21, 2011. This was the PJM RTO's All-Time Peak. On a weather-normalized basis, the PJM RTO 2011 summer peak was 154,383 MW.[96] The difference can be attributed to a very hot summer in most of the PJM Region. Several consecutive days were above 100 degrees, which is unusual for the PJM Region.

Table 64 includes the 2011 and 2012 summer demand forecasts for the PJM Assessment Area. The forecast for the 2012 summer peak is 153,782 MW. The combination of new economic drivers and a downward revision to the economic outlook has resulted in lower peak and energy forecasts for PJM compared to the same year in last year's report. This year's forecast reflects PJM's adoption of an independent consultant's recommendation to replace the load model's previous economic driver (Gross Metropolitan Product) with a variable that incorporates six economic measures (Gross Domestic Product, Gross Metropolitan Product, Real Personal Income, Population, Households, and Non-Manufacturing Employment).

The forecasted demand for 2012 includes the load of Duke Energy Ohio/Kentucky (DEOK), which was integrated into the PJM RTO on January 1, 2012.

[94] Runs from June 1, 2012 through May 31, 2013.

[95] For additional information, see the 2011 PJM Reserve Requirement Study: http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/2011-rrs-study.ashx.

[96] Adjusted for the integration of Duke Energy/Kentucky (DEOK). The forecast in the 2011 Summer Reliability Assessment was 148,941 MW.

**Table 64: PJM Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| **Net Internal** | **137,341** | **142,135** | **4,794** | **3.49%** |
| **Total Internal** | **148,941** | **153,782** | **4,841** | **3.25%** |

A downward revision to the near-term economic outlook for both the U.S. and PJM has resulted in lower peak demand and energy projections in the 2012 load forecast, compared to the 2011 load forecast. This is tied to revised assumptions regarding the timing of the U.S. economic recovery. While growth in later years accelerates, the short-term, seasonal economic outlook is unable to make up the difference between the 2011 and 2012 forecasts until after 2022.

## Demand-Side Management

Acceptance of Demand-Side Management (DSM) resources for the 2012 summer peak period will continue through the end of May 2012. Approximately 4,000 MW has been accepted already and this value continues to grow on a daily basis. Over 11,600 MW of Demand-Side resources were available in PJM during the 2011 summer peak period and similar amounts are projected for the 2012 summer. 2011 actual DSM has been incorporated into this summer's forecast. A total of 581 MW of Energy Efficiency is expected to be available during the 2012 summer peak. Figure 42 and Table 65 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the PJM Assessment Area.

**Figure 42: PJM Demand Response**

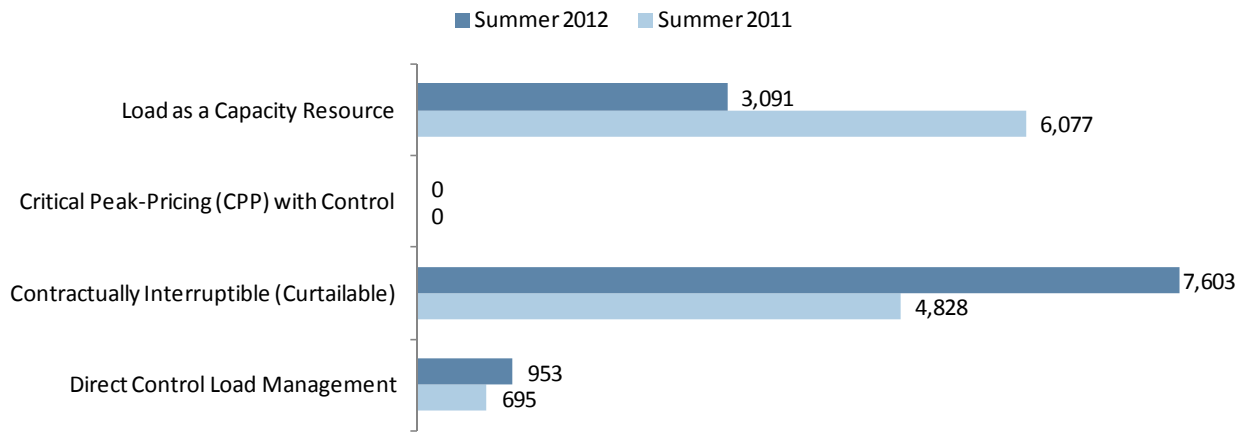



**Table 65: PJM Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 695 | 7,603 | 0 |
| Contractually Interruptible (Curtailable) | 4,828 | 953 | 0 |
| Critical Peak-Pricing (CPP) with Control | 0 | 0 | 0 |
| Load as a Capacity Resource | 6,077 | 3,091 | 0 |
| **Total Demand Response** | **11,600** | **11,647** | **0** |
| **Percentage of Total Internal Demand** | **7.79%** | **7.57%** | **0.00%** |

DSM resources are offered as dispatchable resources, committed resources, or energy products in PJM. Demand response accepted in the Reliability Pricing Model (RPM) Forward Capacity Market is committed and dispatchable, similar to a generator. This DSM is able to be retained for use by PJM operators during capacity emergencies. Energy DSM can be applied as reserves, accepted through the ancillary service market. DSM used for reserves is limited by the RFC standard BAL-002-RFC-02[97] to 25 percent of the operating reserve requirement. This type of DSM is usually fully subscribed and can range up to approximately 2,500 MW during a peak summer day. Economic DSM can also be called for emergency conditions, but is not obligated to perform.

Energy Efficiency programs included in the 2012 load forecast are impacts approved for use in the PJM Reliability Pricing Model (RPM). Measurement and verification (M&V) of Energy Efficiency programs are governed by rules specified in PJM Manual 18B. To ensure the value of an Energy Efficiency resource, providers must comply with the measurement and verification standards, defined in this manual by establishing M&V plans, providing post-installation M&V reports, and undergoing an M&V audit.

## Generation

The primary source of fuel in PJM is coal, at approximately 42 percent (77,000 MW), followed by natural gas at approximately 26 percent (48,000 MW) and nuclear at approximately 18 percent (33,600 MW). No capacity resource changes are expected though the summer of 2012. Acceptance of modifications to capacity categorized as Existing-Certain occur once per year on June 1. Table 66 includes projections of PJM RTO resources for the 2011 and 2012 summer.

**Table 66: PJM Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 180,406 | 185,424 |
| Future-Planned | 0 | 0 |
| Supply-Side Demand Response | 11,600 | 0 |
| Net Capacity Transactions | 1,260 | 217 |
| **Anticipated** | **193,266** | **185,641** |
| Existing-Other and Future-Other | 0 | 0 |
| **Prospective** | **193,266** | **190,471** |

PJM had an increase of 5,007 MW of Existing-Certain capacity since last summer, almost completely due to the integration of DEOK generation. Capacity additions and retirements in the rest of PJM almost netted-out and are listed below:

- A new natural gas combined-cycle 545 MW unit was added by American Electric Power (AEP) at Dresden.
- Two Kearny natural gas units (13 and 14) added 267 MW to the Public Service Electric and Gas Company (PSE&G) generation portfolio.
- A 585 MW natural gas combined-cycle unit named Virginia City was added in AEP.
- The Martins Creek 4 oil unit was uprated by 70 MW in PPL.
- Two Susquehanna nuclear units (1 and 2) in PPL were uprated 90 MW.
- A net of 568 MW of uprates and derates also occurred.

[97] https://www.rfirst.org/standards/Documents/BAL-002-RFC-02.pdf.

- Benning 15 and 16 totaling 548 MW of oil generation were retired in Baltimore Gas and Electric (BGE).
- Gorsuch units 1-4, totaling 189 MW of coal generation, were retired in AEP. The Buzzard Point East and West oil combined-cycle combustion turbines, totaling 210 MW were retired in Pepco.
- The Hudson 1 natural gas unit at 322 MW was retired in PSE&G.
- In PSE&G the Kearny 10 and 11 natural gas units were retired for a loss of 250 MW.
- The State Line 3 and 4 units were totaling 515 MW retired from ComEd.
- No units were brought back into service since the last summer assessment.

PJM has no ongoing long-term outages of generation. Behind-the-meter generation is not considered in capacity calculations but rather offsets load that is also behind-the-meter.

The Laurel Mountain Energy Storage Facility consists of eight "Smart Grid Stabilization System" lithium ion battery modules for a total output of 27.4 MW on the same site as the Laurel Mountain Wind Farm in West Virginia. Two MW (300 kilowatt hours of storage) batteries for frequency regulation have been installed on the same property as the Paradise Solar project in Deptford, New Jersey. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 43 and Table 67.

**Figure 43: PJM Renewable Generation**

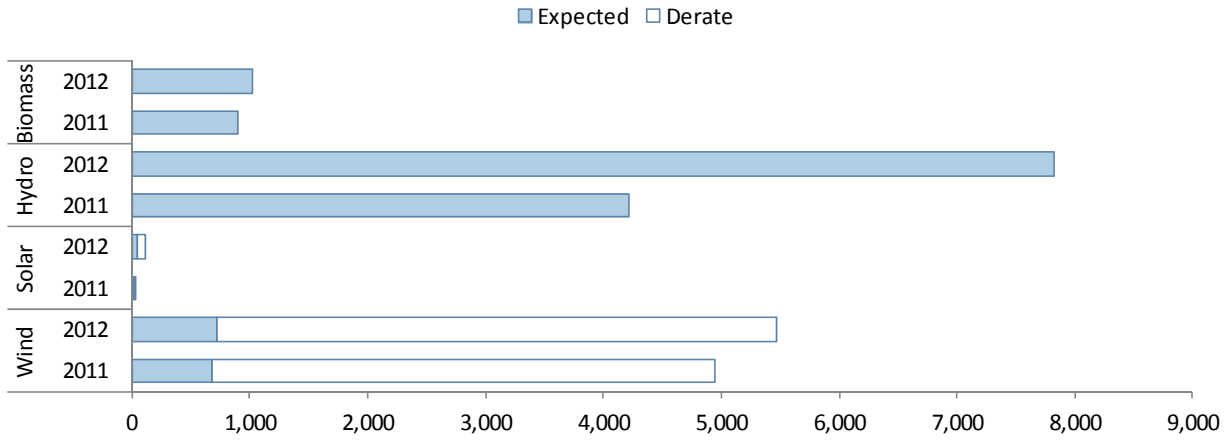



**Table 67: PJM Renewable Generation**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 670 | 711 | 12 | 42 | 4,212 | 7,822 | 896 | 1,023 |
| Derate | 4,272 | 4,761 | 20 | 69 | 0 | 0 | 0 | 0 |
| **Nameplate** | **4,942** | **5,472** | **32** | **111** | **4,212** | **7,822** | **896** | **1,023** |

## Capacity Transactions

All transactions are considered Firm throughout the summer for both specific generation and transmission. Firm contracts are mostly long-term but some are shorter (ranging from one to three years). PJM has no reliance on outside assistance for emergency imports. The availability of emergency generation is not needed for PJM to meet the Reference Margin Level. On-peak capacity transactions projected for the 2012 summer are included in Table 68.

**Table 68: PJM Capacity Transactions**

| Capacity Transactions | Imports | Exports | Net |
|---|---|---|---|
| Firm | 1,453 | 1,236 | 217 |
| Expected | 0 | 0 | 0 |
| **Total** | **1,453** | **1,236** | **217** |

## Transmission

Since the beginning of the last winter peak season, the following facilities have come online:

- Chase City-Clarksville 115 kV line in Dominion
- Brookside-Reedsburg-Longview 138 kV line in ATSI

It is anticipated that the following facilities will go in service prior to the 2012 summer:

- Fredricksburg-Possum Point 230 kV line will get tapped to Garrisonville in Dominion
- Remington-Sowego will be converted from 115 kV to 230 kV in Dominion
- A second Dooms-Dupont-Waynesboro 115 kV line in Dominion
- Yorktown-Hayes 230 kV in Dominion
- Indian River-Bishop 138 kV line in Delmarva

It is anticipated that the following facilities will go in service during the 2012 summer:

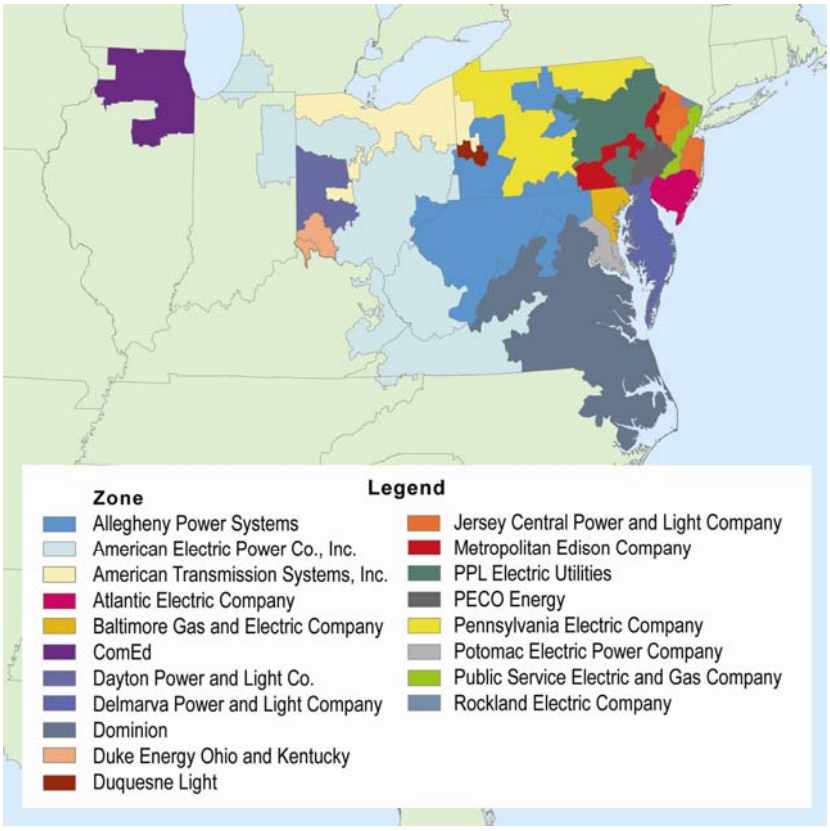
- A second Whiteley-Franklin 138 kV line will be added in AP
- The Galion-GM Mansfield-Longview 138 kV line will be reconfigured to bypass GM Mansfield in ATSI
- Two Perryman-Harford 115 kV lines in BG&E
- Hopewell-Bull Hill 230 kV line in Dominion
- Two new Ritchie-Benning Station ""A"" 230 kV lines in Pepco
- The Linden 230 kV PAR was replaced.

No other substation equipment is expected to be added and no project delays or temporary service outages for transmission facilities (lines or transformers) are expected to impact reliability during this summer. No new transmission projects are required in order to maintain reliability.

## Operations

The PJM Operations Analysis Task Force (OATF) summer assessment did not identify any reliability issues. The OATF does anticipate redispatch and switching procedures to control local thermal and voltage violations in some transmission zones. See Figure 44.

**Figure 44: PJM Transmission Zones**




No special operating procedures are required from the integration of variable resources. PJM has developed a Wind Power Forecast tool and visualization to assist operations. PJM has integrated wind into its automated dispatch systems. PJM does not anticipate any reliability concerns resulting from minimum demand or over generation. Intermittent resources can be required to disconnect. Established procedures ensure reliability concerns resulting from over-generation are addressed.[98]

There are some minor concerns related to the amount of information available to PJM that can be used to determine the amount of demand response to dispatch during emergency conditions. PJM has filed tariff changes with FERC that will require more robust reporting of the demand response operational capability in real-time for Curtailment Service Providers. While this is not considered a reliability concern for PJM, the additional information will help avoid the dispatch of demand response that may not be necessary to meet the need during emergency conditions. PJM has addressed the issue of availability by creating 3 different DR products: Limited DR (10 days for 6 hours per day), Extended Summer DR (unlimited days during a defined summer period for 10 hours per day) and Annual DR (unlimited days for 10 hours per day of a given year). Capacity resources (and DR treated as capacity) in PJM are required to meet PJM's reliability requirements.

PJM requires generation owners to place resources into the "Maximum Emergency Category" if environmental restrictions limit run hours pre-determined levels. Max Emergency units are the last to be dispatched.

[98] http://www.pjm.com/~/media/documents/manuals/m12.ashx.

## Vulnerability Assessment

PJM has very little hydro generation and reservoir levels are expected to be adequate throughout the 2012 summer. PJM expects no problems with warm cooling water. Any one specific generator outage, even if it is long-term, can be replaced with other resources available within PJM. Demand-side resources do not contribute enough to the resource mix to be of great concern for unresponsiveness. Penalties exist for Firm demand-side resources to make unresponsiveness financially unattractive. No special operating procedures are required. PJM has developed a Wind Power Forecast tool and visualization to assist operations.

The Richland 138 kV substation in FirstEnergy (ATSI) will be reconfigured to permit the removal of the Richland SPS in June of 2012. No new Special Protection Schemes (SPS) have been added in PJM since the prior summer.

PJM is assessing the impacts of the CSAPR (Cross State Pollution Rule), MATS (Mercury Air and Toxics Standards) and also state level environmental rules like NJ HEDD (High Electricity Demand Day) on resource adequacy, transmission planning and ancillary services for the PJM footprint. PJM developed an analysis of coal generation at risk of retiring based on an assessment of required environmental retrofit costs vs. the cost of constructing a new natural gas-fired turbine. This at risk generation analysis concluded that there is no overall resource adequacy concern for the PJM footprint, however there may be localized reliability concerns that will need to be addressed either with replacement generation capacity or transmission upgrades if the impacted units are retired or need lengthy environmental retrofit outages. PJM continues to coordinate closely with PJM Generation Owners, PJM Transmission Owners and neighboring systems through the PJM Committee structure and consistent with the PJM Tariff and manuals. In order to maintain system reliability, PJM will designate units as "Reliability Must Run" if their retirement date is targeted to be in advance of required system reinforcements.

PJM requested that all impacted generation owners provide the most accurate information regarding unit retirements, environmental retrofits, unit derates, and potential regulatory issues related to the environmental regulations. Combined with the publically announced unit retirements and the deactivation analysis results, PJM is utilizing this information to address short term impacts and long-term projections through 2018. PJM is communicating with interconnected Transmission Owners as required to address local reliability issues, and also communicating with MISO to compare reliability analyses and coordinate outages.

At this point PJM has added the environmental retrofit outages, to the extent provided by the generation owners, to projections for maintenance outages from 2012-2018, and is continuing to assess the impact to off-peak reliability. PJM will continue to coordinate closely to analyze the impact of retiring generation, planned outage to perform retrofits, normal generation and transmission maintenance outages as well as transmission outages required to perform planning upgrades resulting from retiring generation.

Generation owners have indicated that while at this time there appears to be sufficient time to complete environmental retrofits, if there are delays in scheduling retrofit outages due to system constraint issues or capital budget limitations, then there may be significant challenges in completing the retrofit outages in the required time to comply with environmental regulations.

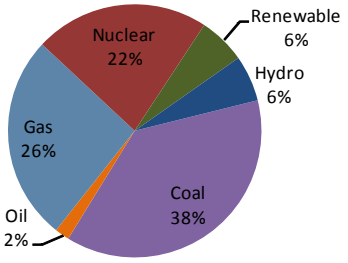
Generators owners are expected to begin environmental retrofit work during the spring 2012 maintenance period.

PJM has established rules/procedures to ensure fuel is conserved to maintain an adequate level on-site fuel supplies under forecasted peak load conditions. PJM coordinates with neighboring entities and gas pipelines to quickly address fuel issues. No fuel supply issues are anticipated. No fuel transportation issues are anticipated.

# SERC-E

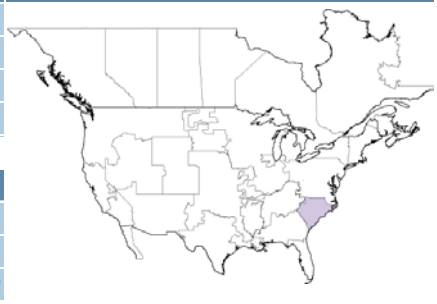
| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 49,768 | - |
| Future-Planned | 635 | - |
| Supply-Side Demand Response | 1,687 | - |
| Net Capacity Transactions | 1586 | - |
| **Anticipated** | **53,676** | **22.52%** |
| Existing-Other and Future-Other | 0 | - |
| **Prospective** | **53,676** | **22.52%** |
| **Reference Margin Level** | - | **15.00%** |

On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **41,562** | **41,378** |
| Demand-Side Demand Response (2012) | - | 1,878 |
| Supply-Side Demand Response (2011) | 1,687 | - |
| **Total Internal** | **43,249** | **43,255** |

Assessment Area Boundary



| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 41,562 | -0.44% |
| Actual Peak Demand | 43,253 | -4.34% |
| All-Time Summer Peak Demand | N/A* | N/A* |

*Boundary changes applied in 2011.

*Note: Additional information regarding the methods and assumptions used in the development of the SERC-E seasonal assessment can be found in Appendix I and on the NERC website.*[99]

## Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the SERC-E Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The reserve margins for the SERC-E Assessment Area are based on Anticipated or Prospective resources. Both the Anticipated Reserve Margin will remain above the Reference Margin Level during the 2012 summer season.

A total of 825 MW of capacity additions will be added during the 2012 summer. According to the SERC-E Assessment Area demand forecast, Total Internal Demand has increased slightly from 43,249 MW to 43,255 MW since the 2011 summer. This equates to an annual growth rate of 0.02 percent.

No reliability concerns in meeting in service dates are expected to significantly impact reliability in the SERC-E Assessment Area.

## Planning Reserve Margins

Reserves are projected to provide an adequate and reliable power supply during the 2012 summer. Generation resources are planned to ensure that reserve margins are met and resource plans are reviewed and revised as needed to achieve these Planning Reserve Margins.

[99] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

In SERC-E, utilities do not adhere to a regional/Assessment Area target or other criteria. Therefore, NERC assigns a default 15 percent Reference Margin Level. However, renewable resources are included in North Carolina utility portfolios to meet the requirements of the state's Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Under this standard, investor-owned utilities in North Carolina will be required to meet up to 12.5 percent of their energy needs through renewable energy resources or Energy-Efficiency measures. Rural electric cooperatives and municipal electric suppliers are subject to a 10 percent REPS requirement.[100] Variable resources are assessed for their availability to meet the needs of customers' reliably and economically, based on the requirements of the standard and maintaining flexibility in making long-term resource decisions. The Anticipated Reserve Margin for the 2012 summer is 22.52 percent. Table 69 includes the 2011 and 2012 reserve margins for the SERC-E Assessment Area.

**Table 69: SERC-E Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 15.00% | 15.00% |
| Existing-Certain & Net Firm Transactions | 22.64% | 22.52% |
| Anticipated | 24.11% | 22.52% |
| Prospective | 24.11% | 22.52% |

No operational problems are anticipated that would detract from the projections in this assessment. For the forecast and any extreme peaks, reserve margins are such that the loss of multiple units can be managed without threatening reliability. The VACAR reserve sharing agreement (RGA) is also available to support recovery from such extreme events. Beyond these measures, transmission reserve margins can also be used to secure market purchases to maintain reliability. As stated in annual integrated resource plan filings with the North Carolina Utilities Commission (NCUC), various entities are evaluating a wide range of factors in order to ensure reliable and cost effective service to customers. Over the next 10 years, entities will be evaluating numerous factors including potential impacts from environmental regulations and rules, integration of renewable energy, new generation technologies and rising commodity costs. These issues will be addressed in future long-term assessments.

## Demand

Slight changes from the 2011 summer actual (43,253 MW) and peak demand forecast (43,249 MW) are primarily due to changes in interruptible demand, class sales mix and load factors used to develop the peak demand forecast. The 2012 summer peak demand forecast is projected to be 43,255 MW. Some entities within the Assessment Area are currently reevaluating forecasting models for the most recent regional and local economic projections.[101] Projections in this Assessment Area are expected to be normal; however, energy sales projections that serve as a primary driver of the load forecast for certain entities are lower based on revised economic growth assumptions. No other significant changes or enhancements were reported for this year's forecasting methods. Table 70 includes the demand forecasts for the 2011 and 2012 summers for the SERC-E Assessment Area.

[100] http://www.ncuc.commerce.state.nc.us/reps/reps.htm.

[101] This information will come from vendors such as Economy.com and IHS Global Insight. Weather projections were taken from various sources such as the National Oceanic and Atmospheric Administration (NOAA) or individual company databases.

**Table 70: SERC-E Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| **Net Internal** | **41,562** | **41,378** | **-184** | **-0.44%** |
| **Total Internal** | **43,249** | **43,255** | **6** | **0.01%** |

## Demand-Side Management

Demand Response and Energy Efficiency programs are projected to be 1,878 MW and 223 MW, respectively. These programs are used to reduce the affects of summer peaks and are considered part of the utilities' resource planning. Demand Response is projected to be 4.34 percent of Total Internal Demand, representing a 0.9 percentage point increase from 2011 projections. This increase is projected to reduce peak demand on entity systems within the Assessment Area. Figure 45 and Table 71 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the SERC-E Assessment Area.

**Figure 45: SERC-E Demand Response**

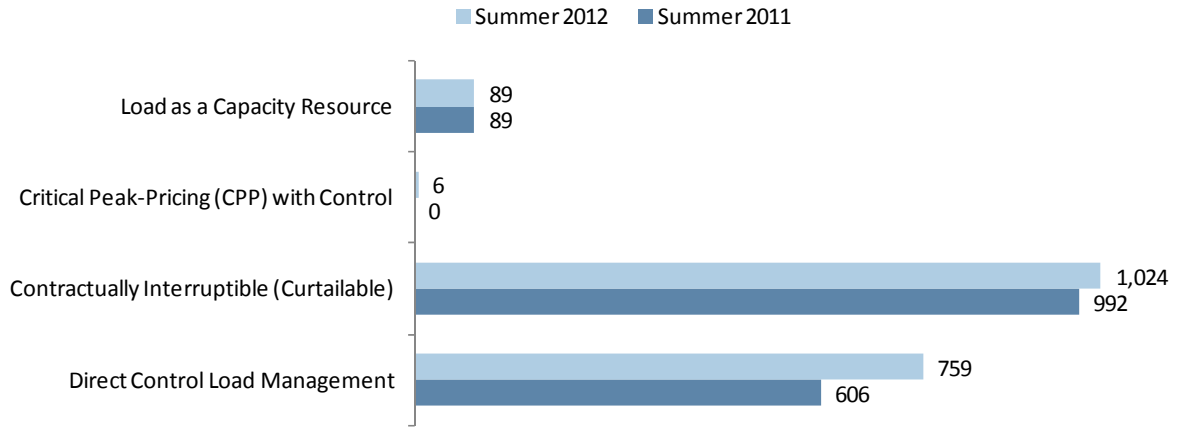



**Table 71: SERC-E Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 606 | 759 | 0 |
| Contractually Interruptible (Curtailable) | 992 | 1,024 | 0 |
| Critical Peak-Pricing (CPP) with Control | 0 | 6 | 0 |
| Load as a Capacity Resource | 89 | 89 | 0 |
| **Total Demand Response** | **1,687** | **1,878** | **0** |
| **Percentage of Total Internal Demand** | **3.90%** | **4.34%** | **0.00%** |

A few entities are still assessing the effects of newly approved Energy Efficiency programs installed on the system in 2010. However, a variety of existing programs that support Energy Efficiency and Demand Response are offered to customers in SERC-N. Some of the programs are current Energy Efficiency and Demand-Side Management (DSM) programs that include: interruptible capacity, load control curtailing programs, residential air conditioning direct loads, energy products loan programs, standby generator controls, residential time-of-use, Demand Response programs (interruptible and related rate structures), Power Manager Power Share conservation programs, residential Energy Star rates, Good Cents new home program, commercial Good Cents program, thermal storage cooling program, H20 Advantage

water heater program, general service and industrial time-of-use, and hourly pricing for incremental load interruptible. The commitments to these programs are part of a long-term, balanced energy strategy to meet future energy needs. Load response will be measured by trending real-time load data from telemetry and statistical models that identify the difference between the actual consumption and the projected consumption absent the curtailment event.

## Generation

Companies within the SERC-E Assessment Area expect to have 50,008 MW of Existing-Certain, 0 MW of Existing-Other, 64 MW of Existing-Inoperable capacity. This capacity is projected to help meet demand during this time period. Coal is the primary source of fuel within this area, representing 37.8 percent of Existing-Certain Resources. Approximately 25 MW of Existing-Certain resources have been added since the prior season. This amount includes 5 MW of solar and 20 MW of biomass. Additionally, 1,470 MW of Future-Planned resources are projected to be added leading up to and during the period. Entities have reported 656 MW of unit retirements prior to the months of June through September, and 382 MW of unit retirements during the month of September. However, new generation came online in late 2011, with more expected in mid-2012. Additional units have not been identified for retirement at this time. Internal company discussions of these options have included mitigation measures that must be explored and considered as part of any decision to retire existing generating units. Table 72 includes projections of SERC-E resources for the 2011 and 2012 summer.

**Table 72: SERC-E Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 49,768 | 49,728 |
| Future-Planned | 635 | 0 |
| Supply-Side Demand Response | 1,687 | 0 |
| Net Capacity Transactions | 1,586 | 968 |
| **Anticipated** | **53,676** | **50,696** |
| Existing-Other and Future-Other | 0 | 0 |
| **Prospective** | **53,676** | **50,696** |

Approximately 25 MW of new generation has been added to the area since the last summer season. There are no new generator uprates in service or out of service generation during the period.[102] 994 MW will be brought back into service for the period. No behind-the-meter generation was reported and no extended outages are expected during this summer. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 46 and Table 73.

[102] SERC methods of data collection do not identify specific uprates or derates throughout the year. Rather, entities reporting to SERC make changes to unit generation continuously throughout the year.

**Figure 46: SERC-E Renewable Generation**

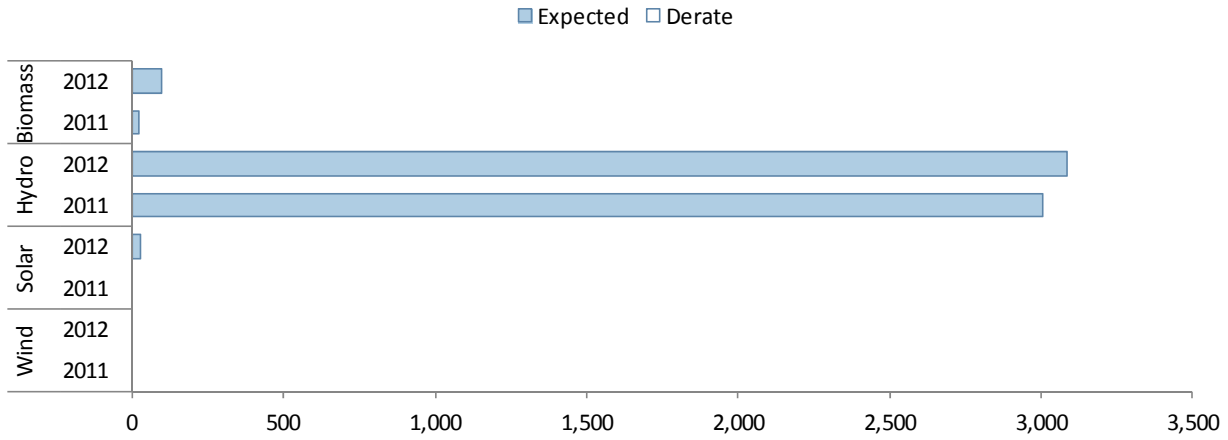



**Table 73: SERC-E Renewable Generation**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 0 | 0 | 0 | 28 | 3,006 | 3,087 | 21 | 97 |
| Derate | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Nameplate** | **0** | **0** | **0** | **28** | **3,006** | **3,087** | **21** | **97** |

Variable resources are limited within SERC-E and are assessed for availability to meet the needs of customers reliably and economically, based on the requirements of the regulatory standards and ability to maintain flexibility for long-term resource decisions. As required, entities will continue to evaluate these and other renewable resources as part of their integrated resource planning process. In addition, no immediate changes in entity planning procedures are needed due to small increments of variable resources.

## Capacity Transactions

Utilities within the SERC-N Assessment Area expect 985 MW of Firm imports and 17 MW of Firm exports for the 2012 summer. These capacity transactions are shown in Table 74.

**Table 74: SERC-E Capacity Transactions**

| Capacity Transactions | Imports | Exports | Net |
|---|---|---|---|
| Firm | 985 | 17 | 968 |
| Expected | 0 | 0 | 0 |
| **Total** | **985** | **17** | **968** |

Most contracts 10-year are agreements for the winter and summer peaking seasons. These include transactions that are both external and internal to the Region and/or the Assessment Area. All purchases are backed by Firm contracts for both generation and transmission and are not considered to be based on partial path reservations. Of the imports and exports shown, very few are associated with Liquidated Damages Contracts (LDCs), in which all contracts include “make-whole” provisions.

Entities within the SERC-E Assessment Area do not rely on resources outside the region for emergency imports, reserve sharing or outside assistance (external resources). Most entities within this area participate in RSAs with other VACAR utilities. Collectively, members of the VACAR RSA hold 1.5 times

the largest single contingency (1,135 MW) in the VACAR RSA area to meet the Reference Margin. The Reserve Sharing Group is projecting adequate reserves throughout the 2012 summer.

## Transmission

The current in service dates for transmission projects are not intended to be at risk for this assessment period. If delays occur that would result in reliability concerns, mitigating actions would be developed accordingly. These measures include re-dispatch of generation, operating procedures, and Special Protection Systems (SPS). On an ongoing basis, companies review and confirm or revise completion dates and monitor the construction status of all projects. Transmission projects planned to address a potential System Operating Limit or Interconnection Reliability Operating Limit commonly receive the highest priority for resources. New construction efforts are focused on completing facilities ahead of seasonal peak periods. Close coordination between construction management and operations planning ensures schedule requirements and completion requirements are well understood. Several large-scale construction projects are planned and will be implemented in phases around seasonal peak load periods to mitigate reliability concerns associated with line clearances and non-routine operating arrangements during periods of higher seasonal loads. Additionally, no significant transmission facility outages are projected to be out of service during the 2012 summer.

To address the need to maintain and enhance reliability, Progress Energy Corporation (PEC) is currently implementing a special transmission project in response to NERC recommendations to utilities entitled.[103] PEC is using Light Detection and Ranging (LiDAR) technology to analyze these conditions. Results from the project are currently being assessed and the project is scheduled to be completed by the end of 2014. Concerns from the plans analyses will be mitigated through an immediate remediation strategy. Other Transmission Operators in the SERC-E Assessment Area are also subject to the NERC recommendation and have not reported any negative transmission reliability or adequacy concerns.

Shifts from the use of coal to natural gas as a generation fuel source due to decreasing costs of natural gas have led to non-typical transmission line power loadings. However, no Transmission Operators in the SERC-E Assessment Area have reported any negative impacts on transmission adequacy.

## Operations

Entities did not specify a need to perform special operating studies for the 2012 summer. No operational problems or constraints are anticipated during the assessment period. Operations designed such that the loss of multiple units can be occur without threatening reliability. The VACAR RSA is in place to support recovery from such extreme events. Generation maintenance schedules are carefully studied and reviewed to ensure reliability concerns are adequately addressed. Accordingly, most maintenance and new construction is scheduled prior to seasonal peak periods.

Since both distributed and variable generation are limited in the SERC-E and because entities maintain a diverse resource mix, special operating procedures are not needed for the integration of variable resources, or minimum demand over generation. Additionally, there are no identified concerns with meeting peak demands by calling on Demand Response resources. Entities do have restrictions on the

[103] *Consideration of Actual Field Conditions in Determination of Facility Ratings*. (Updated: November 30, 2010 (to revise schedule): http://www.nerc.com/fileUploads/File/Events%20Analysis/Ratings%20Recommendation%20to%20Industry%20FINAL-REVISED.pdf.

number of times that emergency Demand Response actions can be employed and these resources are readily available as needed.

Utilities within the area do not currently project environmental or regulatory restrictions for this summer. Lake levels are managed, to the extent weather conditions and inflows allow, mitigating hydro capacity limitations during seasonal peak load periods. There are no other unusual operating conditions anticipated that could impact reliability during the 2012 summer.

## Vulnerability Assessment

Resource adequacy studies can help determine entity reserve margins in the SERC-E Assessment Area. No Special Protection Systems or remedial action schemes are installed in the SERC-E Assessment Area.

Entities in the SERC-E Assessment Area are not aware of any environmental and/or regulatory restrictions that could impact reliability during the 2012 summer. Lake levels are carefully managed, to the extent weather conditions and inflows permit, in order to mitigate hydro capacity limitations during seasonal peak load periods. There are no pending future environmental regulations that are expected to have an impact on the area during the 2012 summer.

Seasonal operating studies have identified no reliability concerns from projected operating conditions. No unusual operating conditions are anticipated for the upcoming summer. Entities will continue efforts to monitor the system through studies, assess line ratings, and improve the system to minimize any negative impacts on the system that could affect reliability for the 2012 summer. Annual planning activities continue to address both near-term and long-term facility needs. Overall, there are no known or projected significant conditions or generator outages that would reduce capacity in the area.

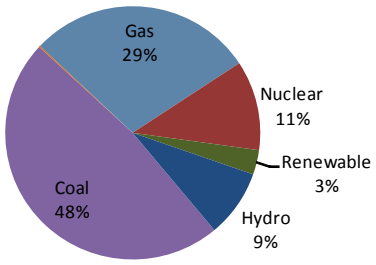
Fuel supply or delivery problems are not anticipated for the period. Utilities maintain enough diesel fuel to run the generation units for an order cycle of fuel. Firm gas supply and transportation contracts are monitored to align with inventory levels of coal and oil supply, natural gas storage, and generation capacity margins. Entities have ongoing communications with commodity and transportation suppliers to communicate near-term and long-term fuel requirements. These communications take into account market trends, potential resource constraints, and historical and projected demands. Regular discussions are framed to ensure potential interruptions can be mitigated and addressed in a timely manner.

Exchange agreements, alternative fuel, or redundant fuel supplies may also be used to mitigate emergencies in the fuel industry or economic scenarios. On-site fuel oil inventory allows for seven-day operations on some units. This was considered to be ample time to coordinate with the industry to obtain adequate supplies. Contracts are in place for months, and often years, into the future. Vendor performance is closely monitored and potential problems are addressed long before issues become critical. Contracts and market positions are considered to be diverse enough to mitigate any supply or delivery issues as they occur.

# SERC-N

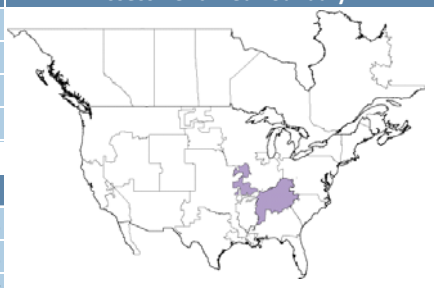
| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 58,228 | - |
| Future-Planned | 878 | - |
| Supply-Side Demand Response | 0 | - |
| Net Capacity Transactions | -1149 | - |
| **Anticipated** | **57,957** | **33.03%** |
| Existing-Other and Future-Other | 964 | - |
| **Prospective** | **59,445** | **36.45%** |
| **Reference Margin Level** | - | **15.00%** |

On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **44,931** | **43,566** |
| Demand-Side Demand Response (2012) | - | 1,536 |
| Supply-Side Demand Response (2011) | 1,915 | - |
| **Total Internal** | **46,846** | **45,102** |

Assessment Area Boundary



| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 44,931 | -3.04% |
| Actual Peak Demand | 45,579 | -4.42% |
| All-Time Summer Peak Demand | N/A* | N/A* |

*Boundary changes applied in 2011.

*Note: Additional information regarding the methods and assumptions used in the development of the SERC-N seasonal assessment can be found in Appendix I and on the NERC website.*[104]

## Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the SERC-N Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with load projections based on economic indicators, long-term weather forecasts, and historic load data.

The reserve margins for the SERC-N Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin is above the Reference Margin Level during the 2012 summer season.

A total of 878 MW of capacity additions will be added before or during the 2012 summer. According to the SERC-N Assessment Area demand forecast, Total Internal Demand has decreased from 46,846 MW to 45,102 MW since the 2011 summer. This equates to an annual growth rate of -3.7 percent.

Some transmission expansion will be required as a result of coal plants being idled. Additionally, severe widespread tornados caused significant system damage in April 2011 and again in March 2012. However, no transmission issues are expected to impact reliability during the 10-year assessment.

TVA's Clay, MS 500/161 kV substation is scheduled to be placed in service prior to the 2012 summer peak. This project will provide enhanced reliability for load in the vicinity.

[104] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

## Planning Reserve Margins

As a result of lower loads and additional capacity, the SERC-N Assessment Area is projecting adequate planning reserve margins during the 2012 summer. Entity results show Anticipated Reserve Margin of 33.0 percent for the upcoming summer. Reserves for 2012 are anticipated to be adequate, assuming typical weather and operating conditions, due to past system development and the weakening of customer growth and energy usage in the area. Table 75 includes the 2011 and 2012 reserve margins for the SERC-N Assessment Area.

**Table 75: SERC-N Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 15.00% | 15.00% |
| Existing-Certain & Net Firm Transactions | 27.98% | 31.02% |
| Anticipated | 27.98% | 33.03% |
| Prospective | 27.98% | 36.45% |

## Demand

Decreases from the 2011 summer actual, 45,579MW, and peak demand forecast, 46,846MW, are primarily due to the slow recovery of the US and regional economies following the recession. The summer peak demand forecast is projected to be 45,102MW. Assumptions have been adjusted for normal weather and current economic conditions for both the United States and regional economies. Since the economic recession, some entities reported significantly adjustments to long-term models and recently enhanced near-term hourly forecast models. Table 76 includes the demand forecasts for the 2011 and 2012 summers for the SERC-N Assessment Area.

**Table 76: SERC-N Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| Net Internal | 44,931 | 43,566 | -1,365 | -3.04% |
| Total Internal | 46,846 | 45,102 | -1,744 | -3.72% |

## Demand-Side Management

Demand Response and Energy Efficiency for the 2012 summer are projected to be 1,536 MW and 104 MW, respectively. These load control programs allow entities to reduce demand and control voltage as needed for reliability purposes. Demand Response is projected to be 3.4 percent of Total Internal Demand this summer, representing a 0.7 percentage point decrease from the 2011 summer. The primary source of current Demand Response is the direct load control program and the interruptible product portfolio. DLC includes a program with interruptible load contracted to and verified by a third party, and has companies that have contractually agreed to reduce their loads within minutes of a request. The estimate used in operational planning takes into account the amount of load available and is not a sum of total load under contract. Other Demand Response products that use control devices are also used by entities on air conditioning units and/or water heaters in residences. Entities are planning for increased demand reductions from these programs. The following are expected to increase in the upcoming years: interruptible demand and load control capabilities, distributor-operated voltage regulation programs, Demand Response pricing products, and introduction of two-way direct load control. Figure 47 and Table 77 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the SERC-N Assessment Area.

**Figure 47: SERC-N Demand Response**

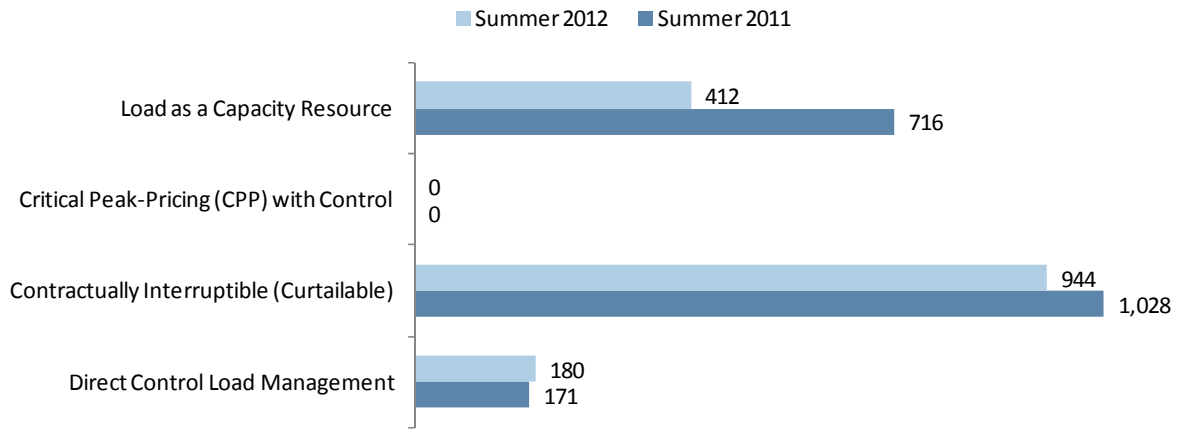



**Table 77: SERC-N Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 171 | 180 | 0 |
| Contractually Interruptible (Curtailable) | 1,028 | 944 | 0 |
| Critical Peak-Pricing (CPP) with Control | 0 | 0 | 0 |
| Load as a Capacity Resource | 716 | 412 | 0 |
| **Total Demand Response** | **1,915** | **1,536** | **0** |
| **Percentage of Total Internal Demand** | **4.09%** | **3.41%** | **0.00%** |

Energy Efficiency programs, such as customer cost-saving energy surveys and audit evaluations, customer education, responsive pricing, residential/commercial conservation, electric thermal storage incentives, new construction (heat pump and geothermal), energy manufactured homes, air-source heat-pump programs (replacing resistance heat 10 years or older), low-income weatherization, low-income assistance, HVAC system improvements, industrial compressed-air programs. Various advanced lighting and third-party verification/measurement groups are currently in operation to residential and commercial customers. Commercial, industrial, and direct-served industry consumers have programs targeted to focus on efficiency improvements in HVAC, lighting, motors and controls, and other electrical-intensive equipment. By the end of 2012, entities are predicting 1,400 MW of additional reductions. These plans and goals recognize that improving peak demand reduction can help slow demand growth in a cost-effective manner, while addressing environmental concerns.

## Generation

Utilities within the SERC-N Assessment Area expect to have 58,228 MW of Existing-Certain and 878 MW of Future-Planned capacity for the 2012 summer. Coal is the primary fuel source within SERC-N, representing 48.6 percent of Existing-Certain resources. No new Existing-Certain capacity has been added since the prior season. However, 878 MW of Future-Planned combined cycle resources are projected to be added prior to, and during the 2012 summer. Additionally, 71 MW is planned to be on inactive reserve this summer, while 412 MW is scheduled to be on 8 weeks of planned maintenance beginning the first week of September 2012. 167 MW is scheduled to be on planned maintenance for

last week of September 2012. Table 78 includes projections of SERC-N resources for the 2011 and 2012 summer.

**Table 78: SERC-N Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 57,610 | 58,228 |
| Future-Planned | 0 | 878 |
| Supply-Side Demand Response | 1,915 | 0 |
| Net Capacity Transactions | 427 | -1,149 |
| **Anticipated** | **59,952** | **57,957** |
| Existing-Other and Future-Other | 0 | 964 |
| **Prospective** | **59,952** | **59,445** |

In accordance with an EPA settlement, 4 units (approximately 480 MW) are scheduled to retire by the end of 2015, and will idle in the spring of 2012.[105] Additionally, 6 units (111 MW each) will be taken out of service on August 1, 2015. The ability of utilities to reliably meet demand is not expected to be impacted by these planned outages. Scenario planning studies are routinely done to assess the impact on system reliability and adequacy for various assumptions of possible unit retirements that might occur during the planning window. The results of those studies are used in the annual planning process and as input to ongoing development of generating fleet strategic plans.

There is no reported behind-the-meter generation and 13 MW of Other/Unknown resources will be available during the 2012 summer. Additionally, extended outages are not expected during the summer period.

Variable resources in SERC-N are limited, although there are some purchases sourced from wind that are included in the transfer amount, and a small amount of solar supply that is part of a customer-owned generation buy-back program. The capacity values of wind contracts are usually based on applicable contract terms. The assumed contribution at the time of the system peak is 12 percent of the nameplate ratings of the associated wind generators (this factor is consistent with the credit applied by RTOs to other wind resources in that same geographical area). The contribution from the customer-owned solar resources is based on the solar insolation values for the area at the time of the summer peak. Entities will continue to evaluate these and other renewable resources as part of their integrated resource planning processes. In addition, no changes in planning procedures are needed for these small increments of variable resources. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 48 and Table 79.

[105] http://www.epa.gov/compliance/resources/cases/civil/caa/tvacoal-fired.html.

**Figure 48: SERC-N Renewable Resources**

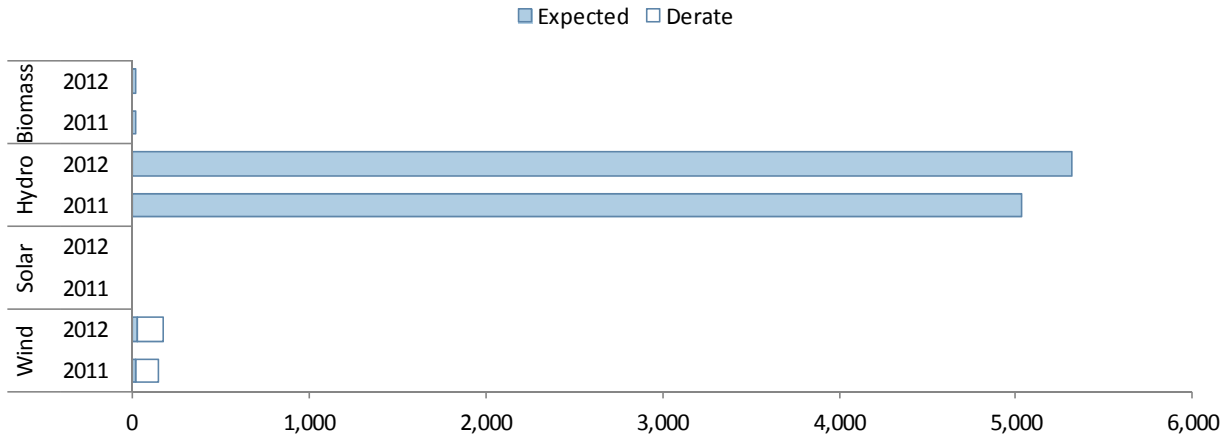



**Table 79: SERC-N Renewable Resources**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 20 | 28 | 0 | 0 | 5,032 | 5,313 | 17 | 17 |
| Derate | 132 | 152 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Nameplate** | **152** | **179** | **0** | **0** | **5,032** | **5,313** | **17** | **17** |

## Capacity Transactions

Utilities within the SERC-N reporting area expect the following imports and exports in the table for the 2012 summer. A majority of these exports are backed by Firm contracts and do not include "make-whole" provisions. However, more than half of the imports reported by entities within SERC-N during the peak month are not backed by a Firm contract. These imports and exports have been accounted for in the reserve margin calculations for the reporting area. Most of the contracts in the area are 10-year agreements for the winter and summer peaking seasons. The majority of these imports and exports were reported to be backed by Firm contracts for both generation and transmission, and do not include "make-whole" provisions. Although not reported, import assumptions are not based on partial path reservations. On-peak capacity transactions projected for the 2012 summer are included in Table 80.

**Table 80: SERC-N Capacity Transactions**

| Capacity Transactions | Imports | Exports | Net |
|---|---|---|---|
| Firm | 263 | 1,412 | -1,149 |
| Expected | 0 | 0 | 0 |
| **Total** | **263** | **1,412** | **-1,149** |

Contingency reserves and emergency imports are obtained from a variety of resources, including the Midwest ISO,[106] PJM, and the TEE Contingency Reserve Sharing Group (TCRSG). The TCRSG consists of three Balancing Authorities that are internal to the area and is intended to provide immediate response to contingencies. This enables the group to comply with the DCS standard and assist in preventing the curtailment of native load. Even though some entities rely on external resources for imports, there are some within the area that do not depend on short-term purchases or transfers from other Regions or

[106] Under Attachment RR of the Midwest ISO ancillary services market tariff.

Assessment Areas to meet demand requirements. Purchase agreements for imports do not include emergency arrangements.

## Transmission

Currently, there are no major concerns with meeting in service dates for transmission improvements or specific projects needed to maintain reliability. If necessary, local area generation may be re-dispatched, or transmission elements reconfigured to alleviate anticipated next contingency overloads. Entities also have the option to invoke NERC TLR procedures[107] in scenarios that are not easily remedied by a local area solution.

## Operations

Many entities within the SERC-N footprint perform routine operating studies (bi-annual load forecast study; monthly, weekly, and daily operational planning efforts; annual assessment of summer peak and temperature, etc.) to assess the system. These studies take into consideration weather, demand, and unit availability to help to address any risks. Based on the results of these studies, entities do not anticipate operational problems during the 2012 summer.

Due to the small amount of variable resources in the Assessment Area, no changes in operating procedures are needed. Recent additions have primarily been in the form of purchased power contracts sourced from wind resources in the mid-west that pose no significant challenges to current operational procedures. As a hedge against applying too much capacity credit for intermittent resources, on-peak impacts from those sources are adjusted to reflect net dependable capacity values to reduce the contribution to resource adequacy calculations and maintain a sufficient level of reliability.

Entities will continue to evaluate the potential to add renewable resources to their portfolios through integrated resource planning studies, and the outcome of those studies may prompt revisions to adequacy assessment procedures in the future. There are no significant operational changes, concerns, or special operating procedures related to distributed resource integration or minimum demand or over generation for the 2012 summer. However, some entities have reported that if low minimum demand occurs in the Midwest ISO region, entities may be required to take units off-line. Net scheduled interchanges, plus the minimum load conditions on all the generators, are assessed to see if adjustments can be made to address low minimum load conditions. System operators have the authority to take units off-line during real-time conditions to address minimum generation issues as needed.

The limited amount of Demand Response in the area does not pose any reliability concerns for this summer. Currently, Demand Response is treated as a resource and not as a reduction in load for some entities, and scenario planning is employed to evaluate the impact on system reliability for differing assumptions of Demand Response effectiveness. Programs that establish a measurement and verification for the program are in progress to track and refine estimates of Demand Response benefits.

Utilities are aware of the potential for regulatory restrictions as a result of environmental rules that will impact generating resource operations. These can include emissions restrictions as well as cooling water source temperature regulation, which can lead to plant de-rates. Routine internal communications

[107] http://www.nerc.com/page.php?cid=5%7C67.

practices will alert operational planners at the onset to any potential regulatory impact to plant operations. At that time, limitations can be factored into operational planning analysis. Mitigation plans are typically developed to reduce system reliability risks. Additionally, some units have been derated due to higher than expected river temperatures and/or lower water flows. As a result, these derates have been partially mitigated for the coming summer season. However, reserves are expected to be well above 15 percent, so any thermal derates should not impact system reliability. Overall, there are no unusual operating conditions anticipated that could impact reliability for the summer.

## Vulnerability Assessment

Resource adequacy assessments covering the next 36 months are performed monthly to assist in identifying limitations or constraints that may impact seasonal adequacy. Long-term adequacy assessments based on 20 years of capacity planning are also performed to make decisions relative to resource acquisitions and project development timelines to ensure system reliability. No system reliability concerns for the period have been identified in the latest resource adequacy studies. Resource availability, fuel availability, and hydro and reservoir conditions are expected to be normal during the summer. However, entities are monitoring adjustments and results to the studies as a consequence of environmental regulations. Currently, there are no Special Protection Systems in SERC-N.

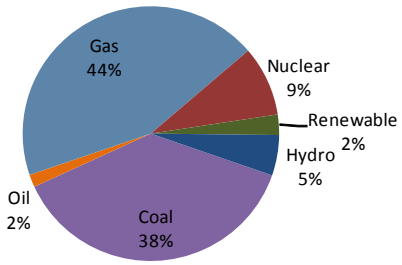
As stated in the previous section, utilities are aware of the risks associated with the current and pending environmental regulations, and have pre-established operational procedures to avoid or address system reliability impacts when identified.

There are currently no anticipated unit retirements that are projected to significantly impact system reliability, nor are there any indications that there will be insufficient time to perform any required retrofits. Entities will continue to conduct scenario planning studies to assess the impact on system reliability and adequacy for various assumptions of possible unit retirements during the period. The results of those studies are used in the annual planning process and provide input to ongoing development of generating fleet strategic plans. The effects of possible future long-term maintenance outages on off-peak reliability are believed to be negligible. Ongoing mitigation plans are developed to reduce system reliability risks. Mitigations may include purchases, new generation, or reliance on reserves. However, as with every regulation that is promulgated, entities will continue to adapt their operations, as needed (*i.e.*, install controls), in order to comply with new regulatory requirements without affecting reliability.

# SERC-SE

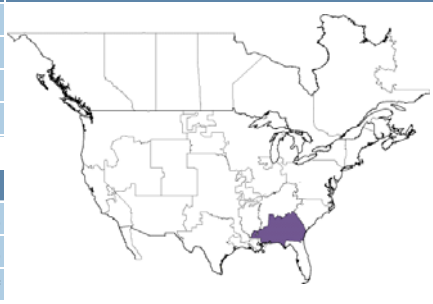
| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 64,342 | - |
| Future-Planned | 50 | - |
| Supply-Side Demand Response | 0 | - |
| Net Capacity Transactions | -1509.6 | - |
| **Anticipated** | **62,883** | **33.45%** |
| Existing-Other and Future-Other | 1,916 | - |
| **Prospective** | **64,799** | **37.52%** |
| **Reference Margin Level** | - | **15.00%** |

On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **47,610** | **47,121** |
| Demand-Side Demand Response (2012) | - | 1,774 |
| Supply-Side Demand Response (2011) | 1,704 | - |
| **Total Internal** | **49,314** | **48,895** |

Assessment Area Boundary



| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 47,610 | -1.03% |
| Actual Peak Demand | 50,309 | -6.34% |
| All-Time Summer Peak Demand | N/A* | N/A* |

*Boundary changes applied in 2011.

*Note: Additional information regarding the methods and assumptions used in the development of the SERC-SE seasonal assessment can be found in Appendix I and on the NERC website.*[108]

## Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the SERC-SE Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The reserve margins for the SERC-SE Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer season.

A total of 80 MW of capacity additions will be added during the 2012 summer. According to the SERC-SE Assessment Area demand forecast, Total Internal Demand has decreased from 49,314 MW to 48,895 MW since the 2011 summer. This equates to an annual growth rate of -0.8 percent.

## Planning Reserve Margins

The SERC-SE Assessment Area is projecting an adequate planning reserve margin throughout the 2012 summer. Utilities do not adhere to any Regional or Assessment Area targets or reserve margin criteria. However, the State of Georgia requires maintaining at least 13.5 percent near-term (less than 3 years) and 15 percent long-term (3 years or more) reserve margin levels for investor-owned utilities. Most entities use the NERC Reference Margin Level of 15 percent, assigned by NERC to Assessment Areas that

[108] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

do not provide a Reference Margin Level. Contributing factors to adequate margins can be attributed to the addition of resources and the expiration or acquisition of Firm purchase contracts. Reserves for the 2012 summer are also anticipated to be adequate due to reductions in load forecasts, resulting from the recent recession and economic downturn, assuming typical weather and operating conditions. Table 81 includes the 2011 and 2012 reserve margins for the SERC-SE Assessment Area.

**Table 81: SERC-SE Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 15.00% | 15.00% |
| Existing-Certain & Net Firm Transactions | 24.91% | 33.34% |
| Anticipated | 24.91% | 33.45% |
| Prospective | 31.60% | 37.52% |

## Demand

Decreases from the 2011 peak demand forecast (49,314 MW) and this summer's peak demand forecast, which is projected to be 48,895 MW, are primarily due to the continuation of a slow economic recovery. The 2011 summer actual peak demand (50,309 MW) was slightly greater than the 2011 peak demand forecast, and entities in the area have found that most of the recovery is led by industrial-class load growth. A change in the class composition due to this unbalanced recovery has lowered the peak forecast for this summer. Historically, economic growth can be rapid following a deep recession. The economic forecasts used in load forecasting, indicate that the current recovery phase has remained expectations. The economic fundamentals of the Region are still strong and forecasters are anticipating the recovery of the job market will yield additional growth, including in the housing market, which will lead to a period of self-sustaining load growth. Table 82 includes the demand forecasts for the 2011 and 2012 summers for the SERC-SE Assessment Area.

**Table 82: SERC-SE Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| Net Internal | 47,610 | 47,121 | -489 | -1.03% |
| Total Internal | 49,314 | 48,895 | -419 | -0.85% |

## Demand-Side Management

Demand Response is projected to be 1,774 MW, with Energy Efficiency included in the load forecast. These programs allow entities within the Assessment Area to have better ability to control various amounts of load and capacity when needed for reliability purposes. Extreme real-time pricing response is considered as a capacity resource. The distribution-level efficiency programs in SERC-SE involve adding capacitors on distribution circuits to reduce line losses and to smooth out voltage drop across the circuit. In addition, the activation of Conservation Voltage Reduction (CVR) helps reduce voltage on the distribution circuit at the voltage regulator or load tap transformer, reducing the customer demand. Additional objectives of some of the SERC-N programs are as follows:

- Help reduce the need to build or purchase capacity
- Respond to volatile wholesale energy markets

- Improve the efficiency (load factor) as well as the utilization of generation, transmission, and distribution systems
- Provide low cost energy to member cooperatives
- Increase off-peak kWh sales

Demand Response is projected to be 3.6 percent of Total Internal Demand, a 0.1 percentage point increase since the 2011 summer. Figure 49 and Table 83 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the SERC-SE Assessment Area.

**Figure 49: SERC-SE Demand Response**

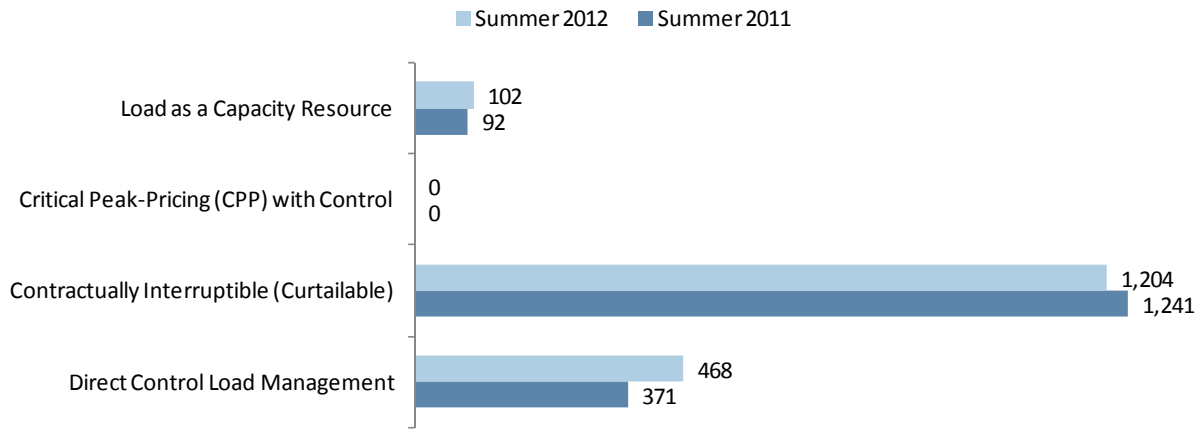



**Table 83: SERC-SE Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 371 | 468 | 0 |
| Contractually Interruptible (Curtailable) | 1,241 | 1,204 | 0 |
| Critical Peak-Pricing (CPP) with Control | 0 | 0 | 0 |
| Load as a Capacity Resource | 92 | 102 | 0 |
| **Total Demand Response** | **1,704** | **1,774** | **0** |
| **Percentage of Total Internal Demand** | **3.46%** | **3.63%** | **0.00%** |

## Generation

Utilities within the SERC-SE Assessment Area expect to have 64,342 MW of Existing-Certain, 1,836 MW of Existing-Other, 0 MW of Existing-Inoperable capacity on-peak. This capacity is projected to help meet demand during this time period. Gas-fired dual fuel units[109] are the primary source of fuel within SERC-SE, making up 45.4 percent of Existing-Certain resources. 841 MW of Existing-Certain resources have been added since the prior season. Additionally, 130 MW of gas-fired Future-Planned resources are projected to be added during the summer period. Entities have reported no unit retirements during the months of June through September. No significant negative impacts on capacity are anticipated for the period. Table 84 includes projections of SERC-SE resources for the 2011 and 2012 summer.

[109] With oil backup.

**Table 84: SERC-SE Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 61,072 | 64,342 |
| Future-Planned | 0 | 50 |
| Supply-Side Demand Response | 1,704 | 0 |
| Net Capacity Transactions | -1,179 | -1,510 |
| **Anticipated** | **61,597** | **62,883** |
| Existing-Other and Future-Other | 3,301 | 1,916 |
| **Prospective** | **64,898** | **64,799** |

Approximately 841 MW of new generation has been added since the last summer season. There are no projections for generator up-rates other generation being taken out of service during the 2012 summer. In addition, no generation will be brought back into service. No behind-the-meter generation was reported, while 417 MW of Other/Unknown resources are expected to serve during the 2012 summer. No extended outages are projected. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 50 and Table 85.

**Figure 50: SERC-SE Renewable Resources**

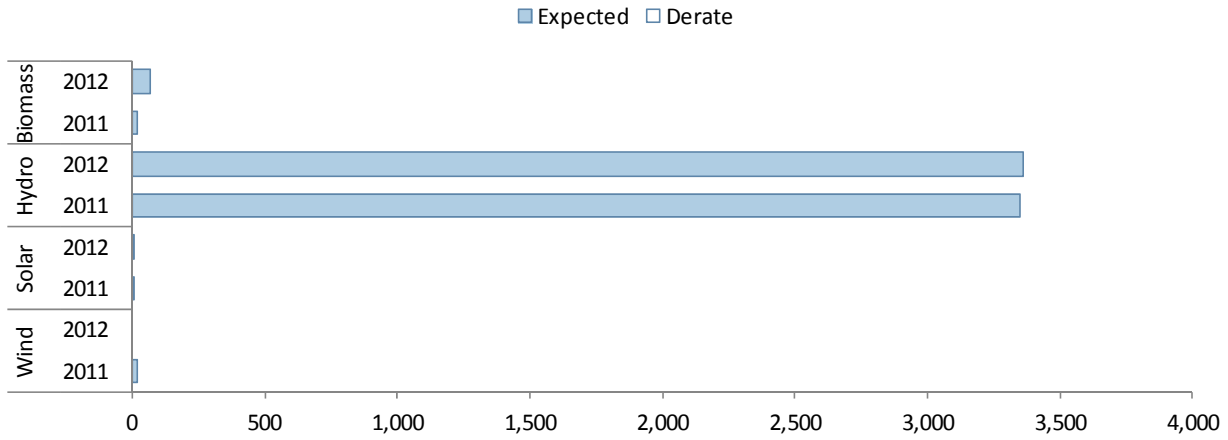



**Table 85: SERC-SE Renewable Resources**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 20 | 0 | 2 | 4 | 3,350 | 3,360 | 17 | 67 |
| Derate | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Nameplate** | **20** | **0** | **2** | **4** | **3,350** | **3,360** | **17** | **67** |

## Capacity Transactions

Utilities within the SERC-SE Assessment Area expect the following imports and exports listed in Table 86 for the 2012 summer. These imports and exports have been accounted for in the reserve margin calculations for the Assessment Area. The majority of the contracts in the area are yearly Firm agreements typically lasting at least five years. Yearly Firm agreements of five years or more are given "Rollover Rights," meaning the contract can be renewed within one year notice of contract expiration. All imports and exports were reported to be backed by Firm contracts for both generation and

transmission, but none are associated with Liquidated Damages Contracts (LDC), or considered "make whole." On-peak capacity transactions projected for the 2012 summer are included in Table 86.

**Table 86: SERC-SE Capacity Transactions**

| Capacity Transactions | Imports | Exports | Net |
|---|---|---|---|
| Firm | 1,150 | 2,660 | -1,510 |
| Expected | 0 | 0 | 0 |
| **Total** | **1,150** | **2,660** | **-1,510** |

Reporting entities maintain emergency-reserve sharing agreements (RGA) with organizations such as the SPP Reserve Sharing Group and entities internal to the area (approximately 250 MW). Other contract agreements with neighboring utilities provide capacity for outages of specific generation. Total emergency generation from these imports were not reported, but are available as needed. Overall, entities are not dependent on outside imports or transfers to meet load.

## Transmission

Currently, there are no concerns with meeting in service dates for transmission improvements or projects needed to maintain reliability. Entities consistently evaluate the transmission system through operating studies and a model construction process. These evaluations address any potential delays in construction and are used to determine switching procedures, operating procedures, or near-term improvements that may be necessary, should an in service date of a bulk facility be adjusted. The Reliability Coordinator (RC) and Transmission Operators (TO) also work with impacted entities to coordinate construction and outage schedules to maintain reliable operations.

## Operations

SERC-SE entities perform studies of operating conditions for 12 to 13 months into the future. These studies include the most up-to-date information regarding load forecasts, transmission and generation status, and Firm transmission commitments for the time period studied and are often updated on a monthly basis. Reliability studies are conducted on one week out, two-day-out and next-day conditions. Studies are updated as changing system conditions warrant. The current operational planning studies do not identify any operational problems. Some entities have conducted assessments of the impact of the Environmental Protection Agency's (EPA) Cross-State Air Pollution Rule (CSAPR) requirements on system dispatch. Although constraints were identified, the EPA stayed implementation of the rule during the study. Currently, it is uncertain at this time whether CSAPR requirements will be reinstated in 2012.

As stated above, entities within the area are constantly updating studies to assess the changes of system conditions as a result of the recent EPA requirements. The current operational planning studies for the period do not identify any operational problems. Entities in this area will continue to manage fossil generating units operating limits related to air and/or water quality. These are derived from both Federal and state regulations. A number of these units have unique limits on operations and/or emissions; some are annual limits while others are seasonal. These restrictions are continually managed in the daily operation of the system while maintaining reliability. Similarly, hydroelectric units in the area are run in cooperation with the U.S. Army Corps of Engineers to maintain water levels and river flow as well as system reliability. Overall, no existing conditions are projected to impact the reliability on the Bulk Power System because of environment restrictions.

The Southern control area routinely experiences significant loop flows due to transactions external to the control area itself. The availability of large amounts of excess generation within the Southeast U.S. results in fairly volatile day-to-day scheduling patterns. The transmission flows are often more dependent on the weather patterns, fuel costs, or market conditions outside the Southern control area rather than by loading within the control area. Significant changes in gas pricing dramatically impact dispatch patterns. All transmission constraints identified in current operational planning studies for the summer assessment period can be mitigated through generation adjustments, system reconfiguration, or system purchases. Overall, there are no unusual operating conditions anticipated that could impact reliability for the summer.

## Vulnerability Assessment

Resource adequacy is determined by extensive analysis of costs associated with expected un-served energy, market purchases and new capacity. These costs are balanced to identify a minimum cost point that is the optimum reserve margin level. No system reliability concerns for the period have been identified in the latest resource adequacy studies. Variable resources have been procured and are not presently relied upon to meet resource adequacy requirements. Resource availability, fuel availability and hydro and reservoir conditions are expected to be normal during the summer.

There are no existing Special Protection Systems (SPS) in the SERC-SE Assessment Area. No SPSs have been installed since last summer, nor are there any plans to install SPSs this summer.

A significant reliability concern involves the uncertainty in generating resource availability in 2015 and beyond, introduced by the recent implementation of EPA MATS rules and other pending environmental rules being promulgated. The SBA Planning Authority is working with Load Serving Entities and Generator Operators to assess resource availability and potential unit retirements. Potential additional transmission enhancements have been identified and will be re-assessed during the spring planning cycle for possible inclusion in 2012 expansion plans. These assessments may also lead to requests associated with MATS implementation requirements to operating units beyond 2015 as needed to maintain reliability.

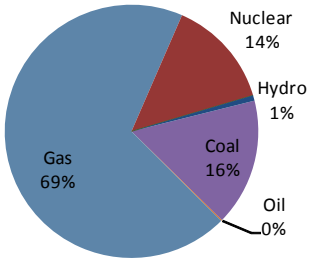
A related reliability concern involves the extensive generation and transmission construction work that must be completed prior to the 2015 implementation of MATS. The Reliability Coordinator and Transmission Operators are working with impacted entities to coordinate construction and outage schedules to maintain reliable operations.

For the upcoming summer season, there are no expected issues or concerns surrounding the timeline to install environmental controls in the SERC-SE Assessment Area to meet regulatory requirements. Additionally, no units are expected to be out of service during the 2012 summer season due to the installation of environmental controls. The fuel supply infrastructure, fuel delivery system, and fuel reserves are all adequate to meet peak gas demand.

# SERC-W

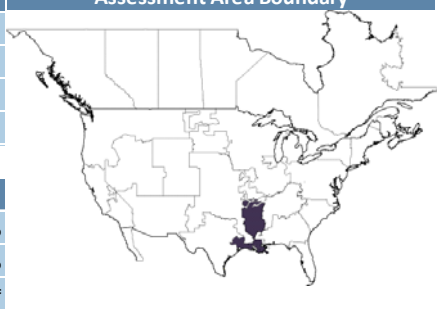
| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 37,145 | - |
| Future-Planned | 1,978 | - |
| Supply-Side Demand Response | 0 | - |
| Net Capacity Transactions | -2554 | - |
| **Anticipated** | **36,569** | **44.02%** |
| Existing-Other and Future-Other | 874 | - |
| **Prospective** | **37,443** | **47.46%** |
| **Reference Margin Level** | - | **15.00%** |

On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **24,228** | **25,392** |
| Demand-Side Demand Response (2012) | - | 11 |
| Supply-Side Demand Response (2011) | 873 | - |
| **Total Internal** | **25,101** | **25,403** |

Assessment Area Boundary



| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 24,228 | 4.80% |
| Actual Peak Demand | 25,585 | -0.75% |
| All-Time Summer Peak Demand | N/A* | N/A* |

*Boundary changes applied in 2011.

*Note: Additional information regarding the methods and assumptions used in the development of the SERC-W seasonal assessment can be found in Appendix I and on the NERC website.*[110]

## Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the SERC-W Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The reserve margins for the SERC-W Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin is above the Reference Margin Level during the 2012 summer season.

A total of 1,978 MW of capacity additions are projected to be added during the summer of 2012. All transmission upgrades associated with the capacity additions have been completed and placed into service. According to the SERC-W Assessment Area demand forecast, Total Internal Demand has increased from 25,101 MW to 25,403 MW since the 2011 summer. This equates to an annual growth rate of 1.2 percent.

Overall, there are no other anticipated reliability concerns for the 2012 summer. To minimize potential reliability issues during the 2012 summer, SERC-W entities studied reliability with a critical and conservative approach. Any issues that result from the studies are addressed within the appropriate timeframe. Curtailment processes and emergency response plans are routinely updated. As necessary,

[110] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

local area procedures, redispatch, and operating guidelines will be implemented to maintain reliability for the summer. Because Energy Emergency Alerts (EEAs) have been issued in the past for the Acadiana Load Pocket, the SPP Independent Coordinator of Transmission-Entergy monitored this area closely and was prepared to implement mitigation plans necessary as part of its Reliability Coordinator function. A two-phase joint project to construct a 230 kV overlay in the Acadiana Load Pocket is scheduled to be completed prior to the 2012 summer. Phase 1 of the project was completed in the fall of 2011 and the Acadiana Load Pocket did not experience any reliability issues during 2011. Additionally, Entergy is currently planning to install a dynamic voltage device to provide voltage support in the south-central Arkansas by the summer of 2013.

## Planning Reserve Margins

The SERC-W Assessment Area is projecting adequate planning reserve margins during the 2012 summer, as none of the three categories will fall below the NERC Reference Margin Level of 15 percent. Entities within this area do not adhere to any reserve margin criteria set by the Regional or Assessment Area. Contributing factors to adequate margins include existing resources, limited and long-term purchase contracts, as well as potential deactivations and anticipated unit outages to plan and procure resources as needed to meet the Reference Margin Level when developing plans for the season. Individual entity criteria have also helped to establish resource adequacy by allocations assigned as a member of the SPP Reserve Sharing Group, Balancing Authority's most severe single contingency, load forecast, and reserve requirement using historical allocations, and Loss-of Load expectation studies (1 day in 10 years). There are no other anticipated reliability concerns projected for the 2012 summer conditions. Table 87 includes the 2011 and 2012 reserve margins for the SERC-W Assessment Area.

**Table 87: SERC-W Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 15.00% | 15.00% |
| Existing-Certain & Net Firm Transactions | 46.19% | 36.23% |
| Anticipated | 46.19% | 44.02% |
| Prospective | 55.31% | 47.46% |

## Demand

Overall, there are no significant differences in the 2011 summer actual (25,585 MW) and peak demand forecast (25,101 MW) to the 2012 summer forecast (25,403 MW). Increases are primarily a reflection of retail load growth and increases in wholesale load. Forecast assumptions are unchanged since the 2011 forecast. Table 88 includes the demand forecasts for the 2011 and 2012 summers for the SERC-W Assessment Area.

**Table 88: SERC-W Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| Net Internal | 24,228 | 25,392 | 1,164 | 4.80% |
| Total Internal | 25,101 | 25,403 | 302 | 1.20% |

## Demand-Side Management

Demand Response and Energy Efficiency are projected to be 11 MW and 0 MW, respectively. These programs are used to reduce peak demand on entity systems within the area. There is no significant

change in the amount of demand response since last summer. Demand-Side Management (DSM) programs among the utilities in SERC-W include: interruptible load programs for larger customers, direct-control load management programs for agricultural customers, and a range of conservation/load management programs for all customer segments. There are no significant changes in the amount and availability of load management and interruptible demand since last year. Figure 51 and Table 89 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the SERC-W Assessment Area.

**Figure 51: SERC-W Demand Response**

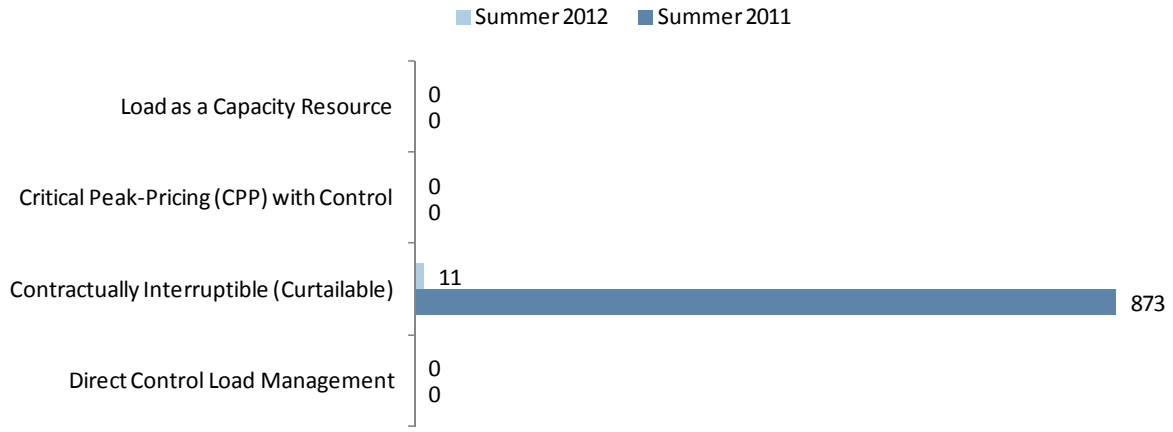



**Table 89: SERC-W Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 0 | 0 | 0 |
| Contractually Interruptible (Curtailable) | 873 | 11 | 0 |
| Critical Peak-Pricing (CPP) with Control | 0 | 0 | 0 |
| Load as a Capacity Resource | 0 | 0 | 0 |
| **Total Demand Response** | **873** | **11** | **0** |
| **Percentage of Total Internal Demand** | **3.48%** | **0.04%** | **0.00%** |

## Generation

Companies within the SERC-W Assessment Area expect to have 37,145 MW of Existing-Certain, 874 MW of Existing-Other, 967 MW of Existing-Inoperable capacity on-peak. This capacity is projected to help meet demand during this time period. Gas generation is the primary fuel source within this area, representing 68.6 percent of Existing-Certain resources. No Existing-Certain capacity has been added since the prior season. However, 1,978 MW of Future-Planned resources are projected to be added during the summer season. Entities have reported no unit retirements during the 2012 summer season. Table 90 includes projections of SERC-W resources for the 2011 and 2012 summer.

**Table 90: SERC-W Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 34,713 | 37,145 |
| Future-Planned | 0 | 1,978 |
| Supply-Side Demand Response | 873 | 0 |
| Net Capacity Transactions | 1,110 | -2,554 |
| **Anticipated** | **36,696** | **36,569** |
| Existing-Other and Future-Other | 3,419 | 874 |
| **Prospective** | **40,115** | **37,443** |

There no projections for generators being put out of service during the period and no known generator up-rates. In addition, 57 MW will be brought back into service for the period. There will be no behind-the-meter generation during the 2012 summer. No ongoing long-term outages have been reported. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 52 and Table 91.

**Figure 52: SERC-W Renewable Resources**

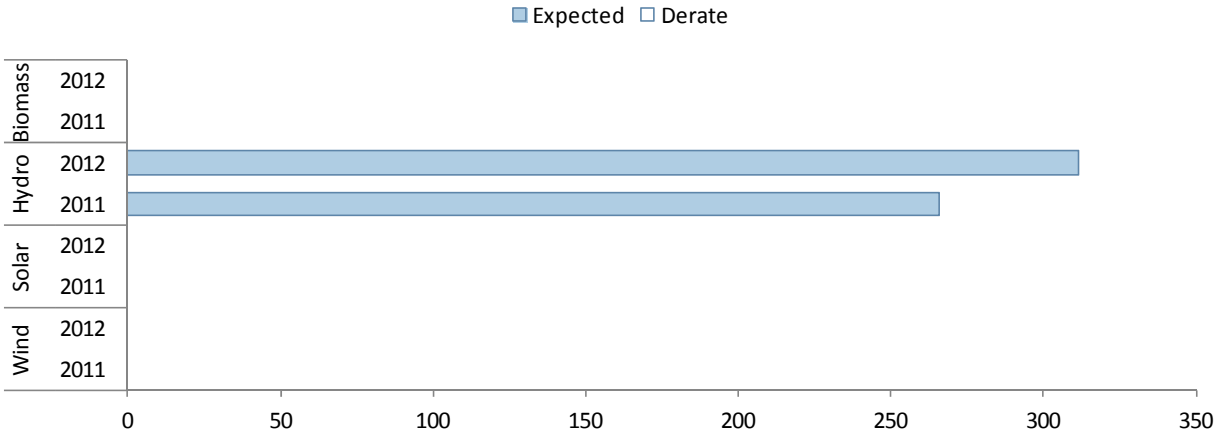



**Table 91: SERC-W Renewable Resources**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 0 | 0 | 0 | 0 | 266 | 311 | 0 | 0 |
| Derate | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Nameplate** | **0** | **0** | **0** | **0** | **266** | **311** | **0** | **0** |

## Capacity Transactions

These imports and exports projected for the SERC-W Assessment Area have been accounted for in the reserve margin calculations. Most of the contracts in the area are agreements for a 10-year period for the winter and summer peaking seasons. On-peak capacity transactions projected for the 2012 summer are included in Table 92.

**Table 92: SERC-W Capacity Transactions**

| Capacity Transactions | Imports | Exports | Net |
|---|---|---|---|
| Firm | 180 | 2,734 | -2,554 |
| Expected | 0 | 0 | 0 |
| **Total** | **180** | **2,734** | **-2,554** |

Reporting entities in the area are dependent on certain imports, transfers, or contracts to meet the demand. Most entities are members of the Southwest Power Pool (SPP) Reserve Sharing Group (RSG). SPP participants generally transfer reserves into the area to either replace largest contingency or supply generation to the area. These reserves are not relied on in the resource adequacy assessment, included as capacity or considered in planning reserve margins. System operators generally coordinate the scheduling and transmitting of the reserves. Total emergency generation from these imports were not reported, but are available as needed.

## Transmission

Entities within the Assessment Area are not expecting any delays in meeting in service dates for projects scheduled for the summer assessment period. Additionally, there are no significant transmission facility outages that impact bulk electric system reliability. Prior to approval of any proposed maintenance outages, studies are completed to identify any impacts on reliability.

## Operations

Companies within the SERC-W Assessment Area regularly participate in SERC NTSG seasonal reliability studies and in the ERAG MRO-RFC-SERC West-SPP (MRSWS) interregional studies. These studies do not exactly include the new SERC-W defined area transfer capabilities, but the SERC-W Assessment Area is very similar to one of the defined company areas that are included in the NTSG 2011 study. These studies test import capabilities into the area and are expected to predict increases or decreases for all examined transfer directions. The interregional transmission transfer capabilities are not currently available, partially due to the recent decision to report as a SERC-W Assessment Area.

Entities are currently studying potential approaches for incorporating variable resources into its planning processes. Due to an insignificant amount of variable generation connected to the distribution system, there are no concerns about integrating these resources onto the system. Wind agreements are used as a tool to allow operators to enhance reliability and can be used in situations such as curtailing for TLR and managing minimum generation problems. However, there are no concerns in this area for the upcoming season. Additionally, entities are not anticipating reliability concerns resulting from availability of Demand Response resources, environmental regulation constraints, or unusual operating conditions that could potentially impact reliability.

## Vulnerability Assessment

Existing and owned resources, limited and long-term purchase contracts, as well as potential deactivations and anticipated unit outages to plan and procure resources needed to meet the Reference Margin Level are considered when developing the one-year and 10-year resource plan. The latest resource adequacy studies performed for the 2012 summer do not show concerns for reliability of the system. Resource availability, fuel availability and hydro conditions are expected to be normal during the summer, except for possible hydro limitations in Texas as stated above. Loss-of-Load studies are performed annually for the current year based on updated load forecast and unit availability data. The long-term test of resource adequacy is met by achieving a 16.85 percent Reference Margin Level.

The Acadiana Load Pocket located in southern Louisiana did not experience any reliability issues in 2011 winter or summer. The addition of the 230 kV lines from Roark to Sellers road and Sellers Road to Meaux in spring 2011, along with the energizing of the Segura 230 kV line in fall 2011, alleviated a portion of the most limiting elements. The 230 kV line from Labbe to Bonin was energized in February 2012, and two other 230 kV lines from Wells to Labbe and Labbe to Sellers Rd. are expected to be energized this summer. Completion of these projects should further alleviate transmission congestion in this area and will conclude the planned Acadiana Load Pocket projects.

No Special Protection Systems (SPS) have been installed in the SERC-W Assessment Area since last summer in lieu of planned bulk power transmission facilities.

There are no environmental or regulatory restrictions projected within the Assessment Area. The CSAPR rules, which have been stayed, were not expected to result in any new Reliability Must Run (RMR) units in SERC-W. In the event that there were insufficient allowances to operate existing RMR units at historical levels, it was still possible to run these units at reduced production levels while still ensuring grid reliability. Additional flexibility was expected with the October, 2011 proposed revision. The increased flexibility allowed by this revision created addition possibilities for compliance, including interstate allowance purchases. Prior to the proposed October limits, some utilities in SERC-W had identified potential transmission upgrades in which acceleration of existing transmission projects was being considered. These projects are current Bulk Electric System projects in various stages of planning, design, and construction. However, with the proposed October limits, no Bulk Electric Systems projects were identified in which acceleration prior to 2012 was required.

Utilities in the SERC-W Assessment Area do not anticipate significant or immediate impacts to system reliability due to the combined effects of CSAPR and other emerging environmental regulations. While the short implementation period allowed for CSAPR initially created concern, other emerging rules are expected to have varying implementation dates that will provide adequate time for planning and execution of control projects. Additionally, coal plants, which are most affected by emerging regulations, are positioned relatively well in regard to their capacity and age, such that most projected environmental projects are currently estimated to be economically viable and not expected to result in early retirements.

Utilities have also indicated that, depending on the deadlines created by the final MACT rule, applicable deadlines for the installation of major pollution control equipment could be problematic for individual plants. These problems are compounded by the uncertainty over the Regional Haze state implementation plan requirements, pending eventually approval by the EPA, could require the installation of additional retrofits at certain plants. Utilities generally believe that impacted coal plants are faced with timing, rational project management, permitting issues, and state public service commission approval. The most immediate threat to reliability is likely to occur in the long-term, considering that many units will be impacted by requirements to implement 316(b) controls and address any reductions driven by lower National Ambient Air Quality Standards (NAAQS). While these regulations could be impactful as soon as 2020, utilities generally do not anticipate the suite of EPA regulations to result in significant facility retirements or generation reductions.

Fuel supply or delivery problems are not anticipated for the summer season. Utilities maintain enough diesel fuel to run the generation units for an order cycle of fuel. Firm gas supply and transportation

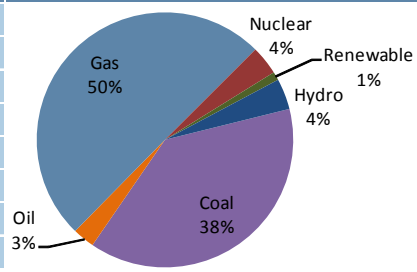
contracts are monitored to align with inventory levels of coal and oil supply, natural gas storage and generation capacity margins. Entities have ongoing communications with commodity and transportation suppliers to communicate near-term and long-term fuel requirements. These communications take into account market trends, potential resource constraints, and historical and projected demands. Regular discussions are framed to ensure potential interruptions can be mitigated and addressed in a timely manner.

Exchange agreements, alternative fuel, or redundant fuel supplies may also be used to mitigate emergencies in the fuel industry or economic scenarios. On-site fuel oil inventory allows for seven-day operations on some units. This was considered to be ample time to coordinate with the industry to obtain adequate supplies. Contracts are in place for months, and often years, into the future. Vendor performance is closely monitored and potential problems are addressed long before issues become critical. Contracts and market positions are considered to be diverse enough to mitigate any supply or delivery issues as they occur.

# SPP

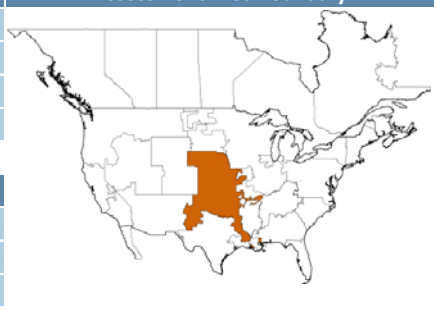
| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 63,547 | - |
| Future-Planned | 2 | - |
| Supply-Side Demand Response | 0 | - |
| Net Capacity Transactions | 1308.651516 | - |
| **Anticipated** | **64,908** | **22.66%** |
| Existing-Other and Future-Other | 2,492 | - |
| **Prospective** | **71,831** | **35.75%** |
| **Reference Margin Level** | - | **13.60%** |

On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **52,261** | **52,915** |
| Demand-Side Demand Response (2012) | - | 1,136 |
| Supply-Side Demand Response (2011) | 1,252 | - |
| **Total Internal** | **53,512** | **54,051** |

Assessment Area Boundary



| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 52,261 | 1.25% |
| Actual Peak Demand | 55,352 | -4.40% |
| All-Time Summer Peak Demand (August 2, 2011) | 51,713 | 2.32% |

*Note: Additional information regarding the methods and assumptions used in the development of the SPP seasonal assessment can be found in Appendix I and on the NERC website.*[111]

## Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the Southwest Power Pool Regional Transmission Organization (RTO) Assessment Area. Data was collected from individual entities and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

The SPP RTO Assessment Area's reserve margins are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain above the Reference Margin Level during 2012 summer season.

A total of 2 MW of capacity additions will be added during the 2012 summer. According to the SPP RTO, the Total Internal Demand forecast has increased from 53,512 MW to 54,051 MW since the 2011 summer. This equates to an annual growth rate of 1 percent.

## Planning Reserve Margins

SPP criteria require members to maintain a minimum capacity margin of 12 percent (13.6 percent Reference Margin Level). The SPP RTO is projected to have an adequate Anticipated Reserve Margins of 22.66 percent, well above the SPP Reference Margin of 13.6 percent. This level of adequacy is supported by the SPP RTO's available generation fleet and the minimal demand increase projected for this summer. 2011 and 2012 summer Planning Reserve Margins for the SPP Assessment Area are presented in Table 93.

[111] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

**Table 93: SPP Reserve Margins**

| Reserve Margin | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Reference Margin Level | 13.60% | 13.60% |
| Existing-Certain & Net Firm Transactions | 20.62% | 22.57% |
| Anticipated | 21.11% | 22.66% |
| Prospective | 25.00% | 35.75% |

## Demand

The projected non-coincident Total Internal Demand forecast for the 2011 summer peak was 53,512 MW, compared with the projected 2012 summer peak demand forecast of 54,051 MW. The actual 2011 summer peak demand was 55,352 MW. The 2011 summer actual peak demand was higher than the forecasted peak demand due to extreme hot weather experienced across the SPP RTO footprint. Table 94 includes the demand forecasts for the 2011 and 2012 summers for the SPP Assessment Area.

**Table 94: SPP Demand**

| Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|
| | 2011 | 2012 | Change (MW) | Change (%) |
| Net Internal | 52,261 | 52,915 | 654 | 1.25% |
| Total Internal | 53,512 | 54,051 | 539 | 1.01% |

The SPP RTO's annual growth rate is consistent with the 2011 assessment numbers. Most areas in the footprint indicated low to moderate load growth, with only a few areas indicating a slow-down in demand growth projections.

## Demand-Side Management

SPP RTO members provide individual Demand Response programs as reductions in the respective load forecasts. The SPP RTO summer assessment reports 911 MW of interruptible and controllable demand and 226 MW of load management.[112] Additionally, the SPP RTO members have reported 237 MW of Energy Efficiency programs to be available during the 2012 summer peak.[113] Figure 53 and Table 95 present the Demand Response forecasted for the 2011 and 2012 summer peaks in the SPP Assessment Area.

[112] SPP RTO does not have the means to measure or verify these Demand Response programs.

[113] The demand response and energy efficiency peak values represent the peak value during the four month summer season and may not be coincident with the peak demand month.

**Figure 53: SPP Demand Response**

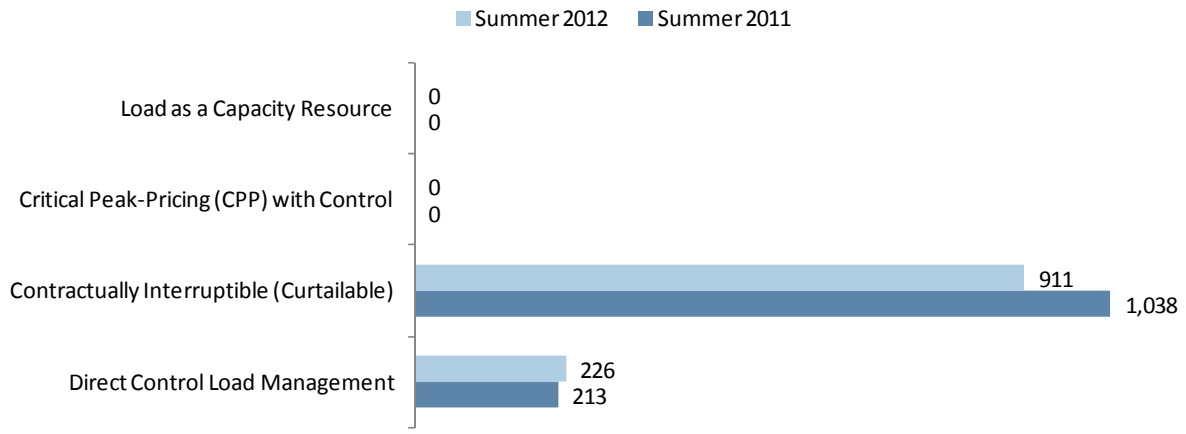



**Table 95: SPP Demand Response**

| Demand Response | Summer Peak Forecast | | |
|---|---|---|---|
| | Supply-Side (Capacity Resource) | Demand-Side (Load-Modifying) | Supply-Side (Capacity Resource) |
| | 2011 | 2012 | 2012 |
| Direct Control Load Management | 213 | 226 | 0 |
| Contractually Interruptible (Curtailable) | 1,038 | 911 | 0 |
| Critical Peak-Pricing (CPP) with Control | 0 | 0 | 0 |
| Load as a Capacity Resource | 0 | 0 | 0 |
| **Total Demand Response** | **1,252** | **1,136** | **0** |
| **Percentage of Total Internal Demand** | **2.34%** | **2.10%** | **0.00%** |

Westar Energy launched its voluntary Demand Response program, WattSaver, in September 2009. WattSaver is open to single and multi-family residential customers, as well as small and medium commercial customers, who receive a free Honeywell Utility Pro programmable thermostat and access to an on-line energy management system. During the months of June through September, WattSaver participants agree to allow Westar to cycle their central air conditioners or heat pumps (on and off in 15-minute intervals) in a coordinated effort to reduce energy demand during peak times. These cycling events normally last about four to six hours or less and occur between noon and 8 p.m. Cycling events occur infrequently and only on weekdays – never on weekends or holidays. In 2011, Westar implemented the program six times. Currently, more than 32,000 Westar customers are enrolled in the program, which provides an estimated 27 MW of load reduction capability. Westar anticipates enrollment of 90,000 participants by the end of 2016.[114]

The SPP RTO member, Oklahoma Gas and Electric (OG&E), installed approximately 40,000 smart meters on customer homes in Norman, Oklahoma since 2010. The information delivery infrastructure was also installed to carry data to and from the customers and OG&E. OG&E estimates that this program will provide 84 MW of Demand Response during peak hours.[115]

[114] http://www.westarenergy.com/wcm.nsf/9696428027fd605386257735006b6631/132c71de2af99f278625791e00651ba7?OpenDocument&Highlight=0,wattsaver.

[115] http://www.ogepet.com/programs/smarthours.aspx.

In January, 2012, Kansas City Board of Public Utilities (KCBPU) started a voluntary program in which a free Honeywell UtilityPro thermostat is installed in homes. Participating customers agree to allow KCBPU to raise the temperature in their home or business by up to two degrees. This will allow KCBPU to reduce summer electricity demand during periods of peak use and extreme heat. These peak events typically last no more than four hours and begin on a weekday afternoon and end in early evening. KCBPU expects to enroll 6,000 customers that will provide a demand reduction of approximately 10 MW.[116]

## Generation

For the 2012 assessment timeframe, SPP RTO forecasts 63,550 MW of Existing-Certain; 6,979 MW of Existing-Other; and 242 MW of Existing-Inoperable capacity. The primary fuel sources in the SPP RTO footprint are gas (42 percent) and coal (40 percent). Several new generation units have been added to the SPP RTO fleet since the 2011 summer assessment, including 308 MW of wind, 552 MW of gas, and 168 MW of coal. Table 96 includes projections of SPP resources for the 2011 and 2012 summer.

**Table 96: SPP Resources**

| Resources | Summer Peak Forecast | |
|---|---|---|
| | 2011 | 2012 |
| Existing-Certain | 61,395 | 63,547 |
| Future-Planned | 203 | 2 |
| Supply-Side Demand Response | 1,252 | 0 |
| Net Capacity Transactions | 1,899 | 1,309 |
| **Anticipated** | **64,748** | **64,908** |
| Existing-Other and Future-Other | 2,057 | 2,492 |
| **Prospective** | **66,804** | **71,831** |

The SPP RTO projects 2 MW of Future-Planned resources to be added between June and September 2012. Approximately 1,028 MW of new wind, natural gas, and coal generation have been added since the last reporting season. No new uprates have been reported since the 2011 summer. Approximately 242 MW of generation are expected to be taken out of service for scheduled maintenance during the 2012 summer timeframe and will not return prior to the season's end. Retirements since last summer include two natural gas units, totaling 37 MW, as well as several units derates.

No long-term maintenance outages were reported and behind-the-meter generation has been included as Existing-Other capacity.

For the 2012 summer, projected on-peak capacity from renewable resources include 99 MW of wind, 5 MW of solar, 2,019 MW of Hydro, and 8 MW of biomass. The expected on-peak capacity values for this variable generation were determined by guidelines established in the SPP Criteria Section 12.0.[117] The maximum capacity for these variable resources is 6,734 MW. A comparison of on-peak renewable generation forecasts for the 2011 and 2012 summer season are presented in Figure 54 and Table 97.

[116] http://www.bpu.com/AboutBPU/BPUoffersFreeUtility.aspx.

[117] Refer to the following SPP criteria: http://www.spp.org/publications/CRITERIA and Appendices 01-25-2011Current.pdf.

**Figure 54: SPP Renewable Resources**

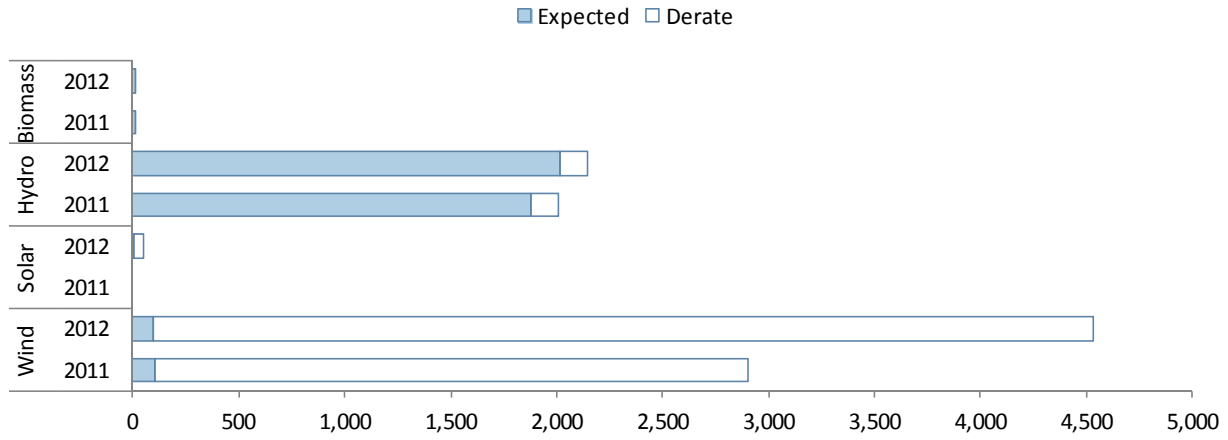



**Table 97: SPP Renewable Resources**

| On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Wind | | Solar | | Hydro | | Biomass | |
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Expected | 107 | 99 | 0 | 5 | 1,876 | 2,019 | 11 | 8 |
| Derate | 2,800 | 4,431 | 0 | 45 | 130 | 127 | 0 | 0 |
| **Nameplate** | **2,907** | **4,530** | **0** | **50** | **2,006** | **2,146** | **11** | **8** |

For the 2012 summer, SPP RTO projects less than 4 percent of the total wind capacity to be available on peak, along with a very small portion of solar. SPP RTO grid operators will continue to monitor any operating challenges for this assessment period. There are no impacts to summer operational procedures due to variable resources.

## Capacity Transactions

SPP RTO members reported the following Firm contract backed imports and exports for 2012 summer in Table 98.

**Table 98: SPP Capacity Transactions**

| Capacity Transactions | Imports | Exports | Net |
|---|---|---|---|
| Firm | 2,346 | 1,037 | 1,309 |
| Expected | 50 | 0 | 50 |
| **Total** | **2,396** | **1,037** | **1,359** |

SPP RTO members, along with some members of the SERC Region, have formed a Reserve Sharing Group (RSG). RSG members receive contingency reserve assistance from each other; the group does not require support from generation resources outside the SPP RTO Region.[118] The SPP RTO's Operating Reliability Working Group sets the RSG's Minimum Daily Contingency Reserve Requirement. The RSG maintains a minimum first Contingency Reserve equal to the generating capacity of the largest unit scheduled to be online, plus one-half of the capacity of the next largest generating unit scheduled to be online.

[118] While the RSG does have generation-owning members outside the SPP footprint, that generation is not expected to provide support into SPP.

## Transmission

Transmission projects listed in the following tables are needed to maintain or enhance reliability during the 2012 summer timeframe. The projects in Table 99 are expected to be placed in service by the end of June 2012.

**Table 99: SPP Transmission Projects Expected In Service by June 2012**

| From Bus Name | To Bus Name | Voltage (kV) | Mileage | Category |
|---|---|---|---|---|
| Arcadia | Ompa-Edmond Garber (Lake) | 138 | | Substation |
| Heizer | Mullergren | 115 | 1.03 | Rebuild/Re-Conductor |
| Holcomb | Plymell | 115 | 11.96 | Rebuild/Re-Conductor |
| Lone Star South | Pittsberg | 138 | | Substation |
| Loup City | North Loup | 115 | | Substation |
| Maloney | North Platte | 115 | | Substation |
| Moore County Interchange | Hitchland Interchange | 230 | 62 | New Line |
| Northwest Manhattan | | 115 | | Substation |
| Northwest Manhattan | Northwest Manhattan | 230/115 | | Substation |
| Oak Park | Jonson | 161 | 2 | New Line |
| Plymell | Pioneer Tap | 115 | 14.87 | Rebuild/Re-Conductor |
| Potter County Interchange | Potter County | 230/115 | | Transformer, new |
| Powell Street | Linwood | 138 | | Substation |
| Riverside Station | Okmulgee | 138 | | Substation |
| Russell | Altus JCT TAP | 138 | | Substation |
| Sooner | Rose Hill | 345 | 53 | New Line |
| South Hays | Hays Plant | 115 | | Substation |
| Stilwell | Archie | 161 | 3.6 | New Line |
| Twin Church | South Sioux City | 115 | 7 | New Line |
| Weleetka | Pharoah | 138 | | Substation |
| Wolfforth Interchange | Yuma Interchange | 115 | | Substation |

SPP RTO identified the projects in Table 100 as necessary to maintain or enhance reliability during the 2012 summer, but SPP RTO members indicated that construction could not be completed until the dates listed. The following construction schedules are not expected to affect reliability due to mitigation plans put in place by SPP RTO members. This includes line switching, local load shedding, and generation redispatch measures.

**Table 100: SPP Transmission Projects Beyond 2012 Summer**

| Project Owner Indicated In-Service Date | RTO Determined Need Date | From Bus Name | To Bus Name | Voltages (kV) | Mileage | Category |
|---|---|---|---|---|---|---|
| 9/1/2012 | 6/1/2012 | Twin Church | South Sioux City | 115 | 10 | New Line |
| 12/1/2012 | 6/1/2012 | Loma Vista East | KC South | 161 | 4 | New Line |
| 12/31/2012 | 6/1/2012 | Easton REC | Knox Lee | 138 | | Substation |
| 12/31/2012 | 6/1/2012 | Easton REC | Pirkey | 138 | | Substation |
| 3/31/2013 | 6/1/2012 | Tuco Interchange | Tuco Interchange | 345/230 | | Transformer, new |
| 6/1/2013 | 6/1/2012 | Atoka West | Tupelo (WFEC) | 138 | 6.5 | New Line |
| 6/1/2013 | 6/1/2012 | Grandfield | Indiahoma | 138 | 3 | Voltage Conversion |
| 6/1/2013 | 6/1/2012 | Indiahoma | Cache SW | 138 | 13.7 | New Line |
| 6/1/2013 | 6/1/2012 | Lynn County Interchange | | 115 | | Substation |
| 6/1/2013 | 6/1/2012 | Southwest Shreveport | Springridge REC | 138 | 7.11 | Rebuild/Re-Conductor |
| 6/1/2013 | 6/1/2012 | Tecumseh Energy Center | Midland | 115 | 19.33 | Voltage Conversion |
| 6/1/2013 | 6/1/2012 | Whitney | Eastex | 138 | 2.49 | Rebuild/Re-Conductor |
| 6/1/2014 | 6/1/2012 | Kansas Tap | W Siloam Springs | 161 | 8.8 | Rebuild/Re-Conductor |
| 6/1/2014 | 6/1/2012 | W Siloam Springs | Siloam City | 161 | 4.2 | Rebuild/Re-Conductor |

## Operations

SPP RTO operations, in conjunction with MISO, created a joint operating guide in 2011 in response to the Missouri River flood-related constraints that occurred in July 2011. This operating guide identified possible constraints for probable, moderate and extreme flood-related forced outage scenarios. If a facility contingency occurs and real-time loading on the monitored facilities exceeds applicable ratings, MISO and the SPP Reliability Coordinator will implement available mitigating and emergency actions as required.

As variable generation penetration and growth continues, further analysis will be required to mitigate any potential reliability issues. SPP RTO is currently investigating measures to integrate more wind into its footprint, such as increasing operating reserves and implementing regional variable resource

forecasting. Operating procedures, such as a unit curtailment plans specific to an individual variable resource, have been and will continue to be developed when transmission constraints are identified.

## Vulnerability Assessment

SPP RTO has areas within the footprint that have been experiencing long-term (>6 months) drought conditions. The areas affected have minimal hydro facilities and unit derates have not occurred at this time, since water levels for bodies of water that supply cooling water are adequate. More recently, the Region has been experiencing heavy winter and spring rain totals that are expected to relieve the drought conditions. There is no resource adequacy or operational concerns for the upcoming summer.

Since the SPP RTO has an abundant generation supply, significant long-term generator outages are not a concern. There are also no short-term concerns related to Demand Response programs, or the potential for these programs to be unresponsive or unavailable, since these programs are not relied upon for resource adequacy.

To ensure the most efficient and effective use of renewable resources, SPP's operations staff must maintain and enhance its ability to project how much wind generation will be available to reliably serve load over given time periods. Unpredictability remains the largest obstacle in effectively integrating wind energy into the SPP RTO generation mix. As wind speeds change, utilities must instantaneously switch to and from other generating resources to compensate for this variability. Increased accuracy in forecasting capabilities regarding the time, location, and speed of wind will significantly enhance the ability of the operator to reliably manage the grid. Accordingly, SPP implemented a new wind forecasting tool in 2011 to generate five-minute, hourly, and day-ahead projections.

The Acadiana Load Pocket located in southern Louisiana did not experience any reliability issues in 2011 winter or summer. The addition of the 230 kV line from Roark to Sellers road in spring 2011, along with the energizing of the Segura 230 kV line in fall 2011, alleviated a portion of the most limiting elements. The 230 kV line from Labbe to Bonin was energized in February 2012, and two other 230 kV lines from Wells to Labbe and Labbe to Sellers Rd. are expected to be energized this summer. Completion of these projects should further mitigate transmission congestion in this area and will conclude all planned Acadiana Load Pocket projects.

The SPP RTO has one Special Protection System (SPS) that was implemented in fall 2011 and is expected to be in service for three years. An automatic control system (ACS) was implemented to curtail output from a wind farm to limit the flow on the MKEC Station – Cudahay line to 90 percent of the line rating, under normal conditions. This SPS will alleviate any overloads in the event of a system contingency or the failure of the ACS system.[119] This temporary solution will be replaced with a permanent one with the construction of a second 115kV North Judson Large to Spearville line, which would eliminate the single contingency exposure to overloading the MKEC Station to Cudahay line.

The Cross-State Air Pollution Rule (CSAPR), adopted by the Environmental Protection Agency (EPA) in July 2011, called for $SO_2$ and annual $NO_X$ reductions that were to begin in January 1, 2012. The SPP RTO

[119] The SPS will measure the current at the MKEC station on the Cudahay line and trip feeder breakers at the wind farm if any phase current on the Cudahay line exceeds the relay set point. In addition, the scheme will trip the 115KV transmission breaker for the wind farm tie at the MKEC station as backup if the overload persists after attempting to trip all four feeders at the wind farm.

performed a CSAPR assessment in September 2011. SPP's reliability assessment of the CSAPR Integrated Planning Model 4.1[120] generation dispatch indicated that the Rule could have serious, negative implications to reliable electric grid operation in the SPP RTO. As a result, the SPP RTO and SPP RE recommended EPA delay the effective CSAPR date for at least a year to allow adequate time for SPP RTO and its members to investigate, plan, and develop solutions for maintaining grid reliability.

In December 2011, the U.S. Court of Appeals issued a stay of CSAPR and the effective date is unknown at this time. Due to the stay, it is not expected that the CSAPR will be in effect in 2012, allowing SPP and its members the opportunity to study, plan, and possibly retrofit to support reliable operation through the 2012 summer season. The SPP RTO has conducted a reliability impact assessment based on the planning activities of members in order to comply with both the CSAPR and the Mercury and Air Toxic Standards (MATS). Based on the assessment results, the SPP RTO does not anticipate that these EPA regulations will have a reliability impact in the SPP RTO area during the 2012 summer assessment period.

The SPP RTO does not expect any generators that could impact reliability to be out of service during the 2012 summer timeframe. Regarding fuel supply issues, the SPP RTO reviews potential supply limitations by consulting with its generation-owning and generation-controlling members. There are currently no known infrastructure issues projected to impact fuel deliverability, as the SPP Region is blanketed by major pipelines and railroads that provide adequate fuel supply. SPP criteria requires coal and natural gas-fired power plants, which make up approximately 40 percent and 42 percent of total generation, respectively to maintain sufficient quantities of standby fuel on-site, in case of deliverability issues.[121]

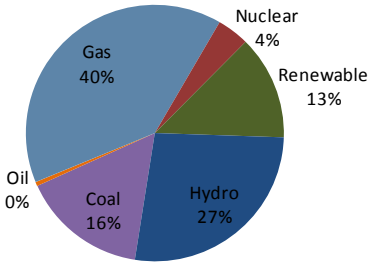
[120] Refer to the following link for additional information on the EPA CSAPR Model: http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html.

[121] Refer to SPP criteria 2.4.2: http://www.spp.org/publications/Criteria and Appendices April 25, 2011.pdf.

# WECC

| 2012 Summer Peak Capacity and Reserve Margins | MW | Margin |
|---|---|---|
| Existing-Certain | 173,855 | - |
| Future-Planned | 1,372 | - |
| Supply-Side Demand Response | 0 | - |
| Net Capacity Transactions | 0 | - |
| **Anticipated** | **175,228** | **21.04%** |
| Existing-Other and Future-Other | 0 | - |
| **Prospective** | **175,228** | **21.04%** |
| **Reference Margin Level** | - | **14.60%** |

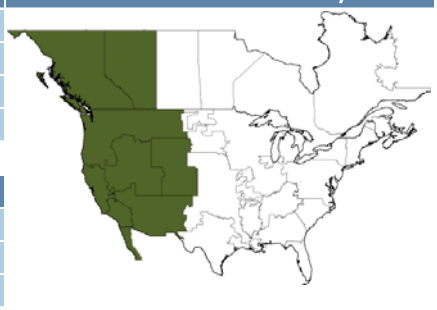
On-Peak Capacity by Fuel Type




| Peak Demand | 2011 | 2012 |
|---|---|---|
| **Net Internal Demand** | **144,874** | **144,766** |
| Demand-Side Demand Response (2012) | - | 4,407 |
| Supply-Side Demand Response (2011) | 4,274 | - |
| **Total Internal** | **149,148** | **149,173** |

| 2011 Summer Comparison | MW | % Change |
|---|---|---|
| Net Internal Demand Forecast | 144,874 | 2.97% |
| Actual Peak Demand | 147,299 | -1.72% |
| All-Time Summer Peak Demand (July 24, 2006) | 161,131 | -10.16% |

Assessment Area Boundary



*Note: Additional information regarding the methods and assumptions used in the development of the WECC seasonal assessment can be found in Appendix I and on the NERC website.*[122]

## Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the WECC Assessment Area and to highlight any reliability concerns associated with resources, including Generation and Transmission, or System Operations under normal weather conditions. Data was collected from individual entities, BAs, and aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data. Subregional data is presented for WECC Planning Reserve Margins, demands, resources, and renewables.

For the Summer Assessment, the WECC Region is divided into four subregions; Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), and California/Mexico (CAMX).[123] These subregions are used for two reasons. First, the subregions are structured around Reserve Sharing Groups. These groups have similar demand patterns and have similar operating practices. Second, the WECC Reliability Coordinator (RC) collects actual demand data from the Balancing Authorities (BA) within the Reserve Sharing groups. Creating the seasonal assessments using the same footprint allows for after-the-fact comparison between demand forecasts and actual demand.

It should be noted that several subregions have different boundaries used for NERC's seasonal compared to the long-term assessments. The Balancing Authority of Northern California (BANC) and the

[122] Please refer to the following webpage for additional information on the development of each Assessment Area's seasonal assessment: http://www.nerc.com/page.php?cid=4|61|409.

[123] For this 2012 summer assessment, individual sections for each WECC subregion have been replaced with a single WECC section that highlights subregional issues as necessary.

Turlock Irrigation District (TID), although physically located in California, are members of the NWPP and their demand and resources are reported in that subregion. Likewise, California's Imperial Irrigation District (IID) is a member of the SRSG with all demand and resources are reported within that subregion. This is the first summer assessment that has reflected these changes, which makes a comparison to prior year's assessments difficult.

The reserve margins for the summer-peaking WECC Assessment Area are based on Anticipated or Prospective Resources. The Anticipated Reserve Margin is projected to remain above the Reference Margin Level throughout the 2012 summer season.

Total capacity additions of 2,941 MW are expected to occur from January through September. According to the WECC demand forecast, Total Internal Demand is expected to increase to 149,173 MW from 147,299 MW for the 2011 summer. This increase equates to an annual growth rate of 1.3 percent.

The NWPP and CAISO routinely issue summer season assessments.[124,125] Also, the Arizona Corporation Commission's Website presents summer preparedness information for some in-state utilities.[126]

## Planning Reserve Margins

The Anticipated and Prospective Reserve Margins for WECC and each of its four subregions are expected to exceed the Reference Margin Level. The reserve margin adequacy is largely due to the construction of power plants in anticipation of a load growth that was interrupted by the economic recession. However, it should be noted that abnormal weather conditions would result in different reserve margins and severe adverse weather conditions or unexpected equipment failure may result in localized power supply or delivery limitations. The Planning Reserve Margins for the WECC Assessment Area and subregions are included in Table 101.

[124] Northwest Power Pool Area Assessment of Reliability and Adequacy.
[125] CAISO 2012 Summer Loads and Resources Assessment.
[126] Arizona Summer Preparedness Presentations.

**Table 101: WECC Reserve Margins**

| WECC | Reserve Margin | Summer Peak Forecast | |
|---|---|---|---|
| | | 2011 | 2012 |
| WECC-TOTAL | Reference Margin Level | 14.20% | 14.60% |
| | Existing-Certain & Net Firm Transactions | 16.72% | 20.09% |
| | Anticipated | 19.32% | 21.04% |
| | Prospective | 19.32% | 21.04% |
| CAMX-México | Reference Margin Level | 11.90% | 11.86% |
| | Existing-Certain & Net Firm Transactions | 31.37% | 22.04% |
| | Anticipated | 31.37% | 22.04% |
| | Prospective | 31.37% | 22.04% |
| CAMX-US | Reference Margin Level | 14.90% | 15.13% |
| | Existing-Certain & Net Firm Transactions | 18.20% | 15.07% |
| | Anticipated | 19.35% | 15.23% |
| | Prospective | 19.35% | 15.23% |
| NWPP-Canada | Reference Margin Level | 12.30% | 12.36% |
| | Existing-Certain & Net Firm Transactions | 15.25% | 49.78% |
| | Anticipated | 17.71% | 49.95% |
| | Prospective | 17.71% | 49.95% |
| NWPP-US | Reference Margin Level | 15.80% | 15.67% |
| | Existing-Certain & Net Firm Transactions | 20.45% | 16.73% |
| | Anticipated | 23.25% | 18.39% |
| | Prospective | 23.25% | 18.39% |
| RMRG | Reference Margin Level | 12.50% | 14.70% |
| | Existing-Certain & Net Firm Transactions | 29.98% | 34.20% |
| | Anticipated | 31.24% | 37.97% |
| | Prospective | 31.24% | 37.97% |
| SRSG | Reference Margin Level | 13.50% | 13.50% |
| | Existing-Certain & Net Firm Transactions | 30.18% | 21.87% |
| | Anticipated | 34.60% | 22.49% |
| | Prospective | 34.60% | 22.49% |

## Demand

For the demand forecasts in this assessment, WECC requests all BAs to submit forecasts with a 50 percent probability of occurrence. These forecasts consider various factors such as population growth, economic conditions, and normalized weather so that there is a 50 percent probability of actual demand exceeding the forecast. The peak demand forecasts presented here are coincident sums of shaped hourly demands, adjusted by the 50/50 demand forecasts. WECC did not perform any quantitative analyses – on a Regional or subregional basis – to assess the variability in demand associated with variations in weather or the economic recession. All margin results used demands associated with normal weather conditions and no attempts were made to address extreme temperature changes.

The aggregate WECC 2012 summer total coincident peak demand is forecast to be 149,173 MW and is projected to occur in July. The forecast is 1.3 percent above last summer's actual peak demand of

147,299 MW, which was established under generally normal-to-slightly-warmer-than-normal temperatures and poor economic conditions in the Region. The 2012 summer coincident peak demand forecast is 0.5 percent above last summer's forecast coincident peak demand of 148,365 MW. The demand data for the WECC Assessment Area and all subregions is included in Table 102.

**Table 102: WECC Demand**

| WECC | Demand | Summer Peak Forecast | | | |
|---|---|---|---|---|---|
| | | 2011 | 2012 | Change (MW) | Change (%) |
| WECC-TOTAL | Net Internal | 144,874 | 144,766 | -108 | -0.07% |
| | Total Internal | 149,148 | 149,173 | 25 | 0.02% |
| CAMX-México | Net Internal | 2,190 | 2,264 | 74 | 3.38% |
| | Total Internal | 2,190 | 2,264 | 74 | 3.38% |
| CAMX-US | Net Internal | 55,442 | 47,279 | -8,163 | -14.72% |
| | Total Internal | 57,646 | 49,490 | -8,156 | -14.15% |
| NWPP-Canada | Net Internal | 18,013 | 17,757 | -256 | -1.42% |
| | Total Internal | 18,035 | 17,769 | -266 | -1.47% |
| NWPP-US | Net Internal | 36,438 | 41,523 | 5,085 | 13.95% |
| | Total Internal | 35,182 | 41,523 | 6,341 | 18.02% |
| RMRG | Net Internal | 10,973 | 10,056 | -917 | -8.36% |
| | Total Internal | 10,565 | 10,503 | -62 | -0.59% |
| SRSG | Net Internal | 28,600 | 28,890 | 290 | 1.01% |
| | Total Internal | 29,049 | 29,402 | 353 | 1.22% |

Over the past decade, peak demand and energy load growth rates have been inconsistent across WECC and within the WECC subregions. Those inconsistencies are of no particular consequence for a seasonal assessment and will be addressed in the WECC section of the NERC *2012 Long-Term Reliability Assessment*.

## Demand-Side Management

Demand-Side Management (DSM) programs offered by Load-Serving Entities (LSE) vary widely. The 2012 demand forecast includes 1,662 MW of Direct Control Load Management (DCLM),[127] 1,741 MW of Contractually Interruptible Demand,[128] 2 MW of Critical-Peak-Pricing with Control, and 1,002 MW of Load as a Capacity Resource. As a percent of Total Internal Demand, total demand response could reduce peak demand by almost 3 percent. In some situations, these programs may be activated by LSEs during high power cost periods but, in general, the programs are only activated during periods when local power supply issues arise. Each LSE is responsible for verifying the accuracy of its DSM and energy efficiency programs. Methods for verification include direct end-use metering, sample end-use metering, and baseline comparisons of metered demand and usage.

[127] Direct control-load-management programs largely focus on air conditioner cycling programs.

[128] Interruptible-demand programs focus primarily on large water-pumping operations and large industrial operations such as mining.

Energy efficiency programs vary by location and are generally offered by the LSE. Programs include: Energy Star builder incentives, business lighting rebates, retail compact fluorescent light bulbs (CFLs), home efficiency assistances, and programs to identify and develop ways to streamline energy use in agriculture, manufacturing, water systems, etc.

State and other regulatory drivers have led to nominal increases in DSM program penetration within the WECC subregions and, within some established market structures, DSM has been established as an ancillary service.

## Generation

In prior seasonal assessments, WECC has reported capacity in the Existing-Other category. However, to ensure consistency between the long-term and the seasonal assessments, WECC will not report Existing-Other capacity. WECC's modeling data[129] for the Western Interconnection included the following:

- Existing-Certain: 173,855 MW
  - Hydroelectric: 30.1%
  - Coal: 17.1%
  - Natural gas: 39.7%
  - Nuclear: 4.3%
  - Other: 8.8%
- Existing-Other: 0 MW
- Existing-Inoperable: 10,643 MW

Additional capacity build from the start of the year through the end of September are classified as Future-Planned and total 2,941 MW. WECC resource projections for the 2011 and 2012 summer are included in Table 103.

[129] The modeling data for renewable resources reflect capacities as of the forecasted December 2011 peak; modeling data for other resources reflect a 2011 year-end in service date.

## Table 103: WECC Resources

| WECC | Resources | Summer Peak Forecast | |
|---|---|---|---|
| | | 2011 | 2012 |
| WECC-TOTAL | Existing-Certain | 169,817 | 173,855 |
| | Future-Planned | 3,870 | 1,372 |
| | Supply-Side Demand Response | 4,274 | 0 |
| | Net Capacity Transactions | 0 | 0 |
| | **Anticipated** | **177,961** | **175,228** |
| | Existing-Other and Future-Other | 0 | 0 |
| | **Prospective** | **177,961** | **175,228** |
| CAMX-México | Existing-Certain | 2,846 | 2,523 |
| | Future-Planned | 0 | 0 |
| | Supply-Side Demand Response | 0 | 0 |
| | Net Capacity Transactions | 31 | 240 |
| | **Anticipated** | **2,877** | **2,763** |
| | Existing-Other and Future-Other | 0 | 0 |
| | **Prospective** | **2,877** | **2,763** |
| CAMX-US | Existing-Certain | 50,241 | 40,402 |
| | Future-Planned | 664 | 76 |
| | Supply-Side Demand Response | 2,204 | 0 |
| | Net Capacity Transactions | 15,691 | 14,000 |
| | **Anticipated** | **68,800** | **54,478** |
| | Existing-Other and Future-Other | 0 | 0 |
| | **Prospective** | **68,800** | **54,478** |
| NWPP-Canada | Existing-Certain | 22,663 | 26,597 |
| | Future-Planned | 689 | 30 |
| | Supply-Side Demand Response | 22 | 0 |
| | Net Capacity Transactions | 1,900 | 0 |
| | **Anticipated** | **25,274** | **26,627** |
| | Existing-Other and Future-Other | 0 | 0 |
| | **Prospective** | **25,274** | **26,627** |
| NWPP-US | Existing-Certain | 47,586 | 48,276 |
| | Future-Planned | 296 | 670 |
| | Supply-Side Demand Response | 1,256 | 0 |
| | Net Capacity Transactions | -4,953 | -1,238 |
| | **Anticipated** | **44,185** | **47,708** |
| | Existing-Other and Future-Other | 0 | 0 |
| | **Prospective** | **44,185** | **47,708** |
| RMRG | Existing-Certain | 14,075 | 13,996 |
| | Future-Planned | 771 | 380 |
| | Supply-Side Demand Response | 408 | 0 |
| | Net Capacity Transactions | -220 | -501 |
| | **Anticipated** | **15,034** | **13,875** |
| | Existing-Other and Future-Other | 0 | 0 |
| | **Prospective** | **15,034** | **13,875** |
| SRSG | Existing-Certain | 40,962 | 41,856 |
| | Future-Planned | 1,284 | 180 |
| | Supply-Side Demand Response | 449 | 0 |
| | Net Capacity Transactions | -3,595 | -6,648 |
| | **Anticipated** | **39,100** | **35,388** |
| | Existing-Other and Future-Other | 0 | 0 |
| | **Prospective** | **39,100** | **35,388** |

WECC's modeling for the 2011 summer assessment peak period gives a total renewable expected capacity of 48,485 MW from a nameplate capacity of 82,846 MW.[130] The breakdown of these capacities by resource type is presented in the Table 104.

**Table 104: WECC Renewable Generation**

| WECC | On-Peak | Summer Peak Forecasts | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Wind | | Solar | | Hydro | | Biomass | |
| | | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| WECC-TOTAL | Expected | 721 | 2,535 | 719 | 850 | 41,157 | 44,052 | 1,107 | 1,048 |
| | Derate | 14,105 | 10,582 | 70 | 393 | 15,377 | 22,550 | 372 | 836 |
| | **Nameplate** | **14,826** | **13,117** | **789** | **1,243** | **56,534** | **66,602** | **1,479** | **1,884** |
| CAMX-México | Expected | 8 | 1 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Derate | 2 | 9 | 0 | 0 | 0 | 0 | 0 | 0 |
| | **Nameplate** | **10** | **10** | **0** | **0** | **0** | **0** | **0** | **0** |
| CAMX-US | Expected | 51 | 402 | 499 | 377 | 4,415 | 1,849 | 469 | 625 |
| | Derate | 2,718 | 988 | 20 | 166 | 4,119 | 7,722 | 2 | 131 |
| | **Nameplate** | **2,769** | **1,389** | **519** | **544** | **8,534** | **9,571** | **471** | **756** |
| NWPP-Canada | Expected | 67 | 511 | 0 | 0 | 12,432 | 13,929 | 418 | 191 |
| | Derate | 1,020 | 425 | 0 | 0 | 1,973 | 1 | 79 | 294 |
| | **Nameplate** | **1,087** | **936** | **0** | **0** | **14,405** | **13,930** | **497** | **485** |
| NWPP-US | Expected | 1,263 | 1,389 | 0 | 36 | 25,084 | 25,708 | 342 | 105 |
| | Derate | 7,093 | 6,789 | 0 | 12 | 6,685 | 11,193 | 23 | 405 |
| | **Nameplate** | **8,356** | **8,177** | **0** | **48** | **31,769** | **36,901** | **365** | **510** |
| RMRG | Expected | 66 | 42 | 4 | 61 | 851 | 1,109 | 9 | 1 |
| | Derate | 1,954 | 1,838 | 4 | 23 | 805 | 815 | 0 | 7 |
| | **Nameplate** | **2,020** | **1,880** | **8** | **84** | **1,656** | **1,924** | **9** | **8** |
| SRSG | Expected | 25 | 5 | 175 | 384 | 2,730 | 1,453 | 62 | 45 |
| | Derate | 559 | 719 | 70 | 183 | 957 | 2,794 | 50 | 51 |
| | **Nameplate** | **584** | **724** | **245** | **568** | **3,687** | **4,247** | **112** | **95** |

The highly variable nature of wind and solar resources complicates daily power grid operation, often more significantly during off-peak periods than during on-peak periods. Operational procedures, such as implementing and testing resource curtailment capability and increased reserve requirements, are expected to address the wind and solar generation variability issues. Operational procedures, generally involving implementing and testing resource curtailment capability and increased reserve requirements, are expected to adequately address the wind and solar generation variability issues.

## Capacity Transactions

The WECC Region does not rely on imports from outside the Region when calculating peak demand reliability margins, or on outside assistance or external resources for emergency imports. WECC does

[130] The renewable expected capacity modeling for wind resources uses generation curves created from three years' of one-hour interval wind speed data. Expected Capacity modeling for solar resources uses generation curves created from two years of insolation data. Hydro generation is dispatched economically, limited by expected annual energy generated during an adverse hydro year. Biomass and geothermal capacities are based on nominal plant ratings.

not model exports to areas outside of WECC and does not model subregional purchase (sale) contracts or associated transmission. Only transfers from remotely-owned, large thermal and hydroelectric units (resources located outside the owners subregion) are allocated to the owner's subregion. All other transfers are modeled as theoretical transfers that could happen, but do not have actual contracts. This modeling treatment ensures that each resource is counted only once.

## Transmission

No project delays or temporary service outages for transmission facilities have been reported that will adversely impact reliability during the 2012 summer period and no specific projects have been reported that are needed to maintain reliability. Accelerating the completion of Barre-Ellis and Sunrise Powerlink transmission projects are noteworthy projects that would help alleviate transmission constraints in Southern California.

## Operations

WECC staff does not perform special operating studies concerning extreme weather or drought conditions for the seasonal assessments. However, these studies are performed by the individual Load-Serving Entities (LSE), and BAs within WECC, and there have been no reports of extreme weather or drought-related issues.

The California Independent System Operator (CAISO) has developed and employed a procedure to address an over-generation situation. When minimum demand and over generation becomes an issue due to the integration of variable resources, the procedure allows for the following actions:

- Use of decremental market bids to reduce the amount of over generation;
- Request generating units and pump loads to operate at their dispatch operating targets
- Offer energy for sale to other BAs
- Instruct generating units to reduce generation or imports on pro-rata basis to meet mitigation targets
- Issue mandatory dispatch instructions to specific generating units or external imports

The introduction of formalized operating procedures by the CAISO and other BAs has directly addressed the issue of over generation during minimum demand periods; therefore, over generation is not currently an operational concern within the Western Interconnection. While over generation may be addressed through various resource curtailment approaches, none of these approaches are without associated costs to either or both the generation owners and the consumers.

As discussed previously, LSEs within the Region have implemented demand response programs and intend to activate these programs when warranted by local operating conditions. These programs are generally geared toward activation on either short notice, or in many cases, no notice, and are often a final step before the interruption of Firm service to customers.

Power plants operate under numerous environmental and other regulatory restrictions, including emission, water level, and water temperature limitations. The cumulative magnitude of the restrictions, although not quantified, is incorporated into the expected on-peak capacities used for this assessment. These restrictions are not expected to adversely affect reliability during the summer period.

The CAISO has reported a West Sacramento Special Protection System (SPS) as a permanent solution to a double-circuit line outage and two SPSs that are temporary bulk power transmission facility solutions for thermal overloads.

## Vulnerability Assessment

The West experienced a relatively warm and dry 2011/2012 winter, resulting in sparse snow pack in some areas. Runoff forecasts for California basins are one-third or less of normal conditions, while the Colorado River Basin is in the twelfth year of a persistent drought. However, a March Columbia River flow forecast was at 93 percent of the 30-year average flow, measured at The Dalles, Oregon. It is expected that the reduced river flows will result in increased thermal-based energy generation, but will not significantly impact the ability to meet peak demand. The margin information and assumptions presented in this assessment reflects adverse hydroelectric generation condition.

WECC entities have not reported any pending environmental regulations that would have an impact on their upcoming season planning and, consequently, have not included potential environmental regulation effects in their upcoming season plans.

The 2,250 MW San Onofre plant in southern California has experienced premature wear in the steam tubes for both of the plant's units and they have been shut down for repairs. The planning reserve margins for California are projected to be quite tight for the summer season and should the plant fail to return to service prior to a heat wave, emergency load shedding could be implemented in the San Diego and Los Angeles Basin portions of California. Officials are developing a plan to encourage local conservation. In addition, the CAISO has procured capacity from the Huntington Beach Unit 2 and is exploring other mitigation measures that can be put in place quickly should the plant not return to service this summer.

In additions to the San Onofre issue previously discussed, a 900 MW Intermountain Generating Station unit that provides power to the Los Angeles Basin has been forced out of service since late December. The unit is currently undergoing repairs, and it is expected that the unit will return to service by June 1, 2012. Area entities have not reported other long-term maintenance outages as a concern relative to off-peak reliability.

WECC entities also reported routine coordination of fuel supply needs with fuel and transportation suppliers on several levels. For example, significant portions of the coal supply are acquired under long-term contracts with mines and transportation providers, and the power plants generally have significant on-site coal storage facilities. These long-term arrangements are largely unaffected by short-term conditions such that seasonal planning coordination beyond pre-established parameters is minimal. Alternatively, natural gas deliveries are often scheduled on a shorter-term basis – often daily. This short-term acquisition process, coupled with (generally) very limited storage located near power plants and gas pipeline pressure limitations, may lead to supply interruptions if other conditions, such as an unexpected cold snap or colder-than-expected temperatures occur. These temperature-driven supply interruption events are typically limited to the winter and are not expected to affect reliability this summer.

On September 8, 2011, customers in Baja California, Mexico, southern California's Imperial, Orange and San Diego counties, and a small portion of southwestern Arizona experienced a major power outage. Several entities within WECC have taken, or are in the process of taking actions to prevent similar

disturbances in the future. These actions include the implementation of additional real-time data exchange and coordination with additional entities in the Southwest. These processes will help facilitate a more detailed monitoring capability of neighboring systems in their energy management systems and real-time contingency analysis applications. In addition, the WECC RC has coordinated the development of an interim monitoring procedure of the San Diego and Imperial Valley areas with specific actions that will be taken for overload conditions. Additional information is now available in the joint FERC and NERC report released in April 2012.[131]

[131] http://www.nerc.com/fileUploads/File/News/AZOutage_Report_01MAY12.pdf.

# Appendix I: About this Report

## About This Report

The *2012 Summer Reliability Assessment* provides an independent view of the seasonal reliability for the North American bulk power system,[132] while identifying trends, emerging issues, and potential concerns. Additional insight will be offered regarding seasonal resource adequacy and operating reliability, and an overview of projected electricity demand growth, and assessment area self-assessments.

NERC's primary objective in providing this assessment is to identify seasonal reliability concerns on the North American bulk power system and to offer recommendations to address these issues. Additionally, NERC's seasonal assessments provide a platform for system users, owners, and operators to systematically document planning procedures, identify vulnerabilities, and exchange critical information for the impending season.

## Assessment Preparation

This assessment is prepared by NERC in its capacity as the Electric Reliability Organization.[133] NERC cannot order construction of generation or transmission or adopt enforceable standards having that effect, as that authority is explicitly withheld by Section 215 of the U.S. Federal Power Act and similar restrictions in Canada.[134] In addition, NERC does not make any projections or draw any conclusions regarding expected electricity prices or the efficiency of electricity markets.

This report was developed by NERC in its capacity as the Electric Reliability Organization (ERO). The assessment area sections were developed by the Reliability Assessment Subcommittee (RAS), which is under the direction of the NERC Planning Committee (PC). The data and information presented in this assessment was submitted by each of the eight Regional Entities on an Assessment-Area basis. Additional data was incorporated by NERC staff with sources provided when applicable.

## 2012 Assessment Enhancements

### *Assessment Structure*

In prior NERC assessments, seasonal and long-term projections were presented in a single document that included information about the methods and assumptions (*i.e.*, load modeling) employed by each assessment area to arrive at these projections. Although the outlook changes from season to season, the methods and assumptions used by each assessment area are more permanent. Accordingly, NERC assessments will be provided in two parts:

- Part I: Seasonal Outlook
- Part II: Assessment Methods and Assumptions

[132] Bulk power system reliability, as defined in the *How NERC Defines Bulk Power System Reliability* section of this report, does not include the reliability of the lower voltage distribution systems, which systems account for 80 percent of all electricity supply interruptions to end-use customers.

[133] Section 39.11(b) of the U.S. FERC's regulations provide that: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[134] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf.

The information included in Part II will ultimately be provided on the NERC website, eliminating the need for a separate report. Detailed information for each assessment area will be posted through an online portal, reflecting the most up-to-date load-forecasting, resource adequacy studies, and other critical information used in the development of seasonal and long-term projections.

Assessment areas are subjected to scrutiny and review by the entire Reliability Assessment Subcommittee (RAS). This review ensures that RAS members fully convinced that each assessment area provides an accurate and complete assessment of seasonal and long-term reliability. Data is further reviewed to ensure that transfers into or between two areas are validated.

The NERC Planning Committee endorses this report prior to being sent to the NERC Board of Trustees (BOT) for approval. The draft, endorsed by the Planning Committee includes comments received from representatives on the NERC Operating Committee and the Member Representative Committee (MRC). Drafts of the document are considered confidential and embargoed until approval is received from the NERC BOT.

In the *2012 Summer Reliability Assessment* baseline information on future electricity supply and demand is based on several assumptions:[135]

- Supply and demand projections are based on industry forecasts submitted in May 2012. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data may be submitted throughout the drafting timeframe (May – September).
- Peak demand and Planning Reserve Margins are based on average weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Region's self-assessment.
- Generating and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in-service as planned; planned outages take place as scheduled; retirements are scheduled as proposed
- Demand reductions expected from dispatchable and controllable Demand Response programs will yield the forecast results, if they are called on.
- Other peak Demand-Side Management programs, such as Energy Efficiency and price-responsive Demand Response, are reflected in the forecasts of Total Internal Demand.

***Updated Demand Response Concepts and Categorization***

The continued saturation of Demand Response highlights the need for NERC's reliability assessments to accurately reflect how these resources are treated in each assessment area. Demand Response programs offer different functionality that ultimately depends on how each program is used by the respective Balancing Authority. While some Demand Response programs are considered supply-side resources, others are considered as demand-side resources, or load modifiers. In 2010, the NERC

[135] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each Regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC Regional projections, there is a 50 percent probability that actual demand will be higher than the forecast midpoint and a 50 percent probability that it will be lower (50/50 forecast).

Resource Issues Subcommittee (RIS) released several recommendations[136] to address the treatment of Controllable Capacity Demand Response (CCDR) in future NERC reliability assessments. Most importantly, all CCDR were to be considered supply-side resources.

Attempts to impellent a uniform approach presented unforeseen complications in NERC's 2011 reliability assessments. While certain assessment areas internally modeled CCDR as a load-modifier in their Loss-of-Load Expectation (LOLE) studies, NERC was collecting and presenting CCDR exclusively as a supply-side resource. The most critical impact was reflected in a misrepresentation of the assessment area's reserve margins.

The Reliability Assessment Subcommittee (RAS) revisited this issue in early 2012 and provided new recommendations for the treatment of Demand Response. Assessment areas were asked to report Demand Response based on how it is modeled within their respective LOLE studies. Ultimately, Demand Response should be considered as a demand-side resource, only if the assessment area does not carry reserves for this curtailable demand during the peak.

***Updated Reserve Margin Calculations***

The modifications to the collection and presentation of CCDR have required additional modifications to the Planning Reserve Margin Calculations. The pre-2010 calculation, 2011 calculation and 2012 calculations are presented in Table I-1.

**Table I-1: Reserve Margin Calculations**

| | | | |
|---|---|---|---|
| **Pre-2011** | $RM = \frac{[Capacity + CCDR_{TOTAL}] - [Total\ Internal\ Demand - CCDR_{TOTAL}]}{[Total\ Internal\ Demand - CCDR_{TOTAL}]}$ | → | $RM = \frac{[Capacity + CCDR_{TOTAL}] - [Net\ Internal\ Demand]}{[Net\ Internal\ Demand]}$ |
| **2011** | $RM = \frac{[Capacity + CCDR_{SUPPLY}] - Total\ Internal\ Demand}{Total\ Internal\ Demand}$ | → | $RM = \frac{[Capacity + CCDR_{SUPPLY}] - Total\ Internal\ Demand}{Total\ Internal\ Demand}$ |
| **2012** | $RM = \frac{[Capacity + CCDR_{SUPPLY}] - [Total\ Internal\ Demand - CCDR_{DEMAND}]}{[Total\ Internal\ Demand - CCDR_{DEMAND}]}$ | → | $RM = \frac{[Capacity + CCDR_{SUPPLY}] - [Net\ Internal\ Demand]}{[Net\ Internal\ Demand]}$ |

Total Internal Demand — The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system (forecast). Total Internal Demand includes adjustments for the indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electricity use, and all non-dispatchable Demand Response Programs. This value is used in the Planning Reserve Margin calculation.

Net Internal Demand (MW) — Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce peak load.

***NERC Assessment Areas***

Prior to the release of the *2011 Summer Reliability Assessment*, NERC had presented assessment data and information based on Regional Entity boundaries. These boundaries were established through consideration of the respective membership of each Regional Entity, comprising of both Planning Coordinators and Load Serving Entities (LSEs). There are approximately eighty NERC Planning

[136] Recommendations for the Treatment of Controllable Capacity Demand Response Programs in Reserve Margin Calculations: http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf.

Coordinators, ten of which are Independent System Operators (ISOs) and/or Regional Transmission Organizations (RTOs) which encompass a large portion of North America. Four of these Planning Coordinators operate in multiple Regional Entities listed below:

- American Transmission Co., LLC: MRO, RFC
- Midwest Independent Transmission System Operator, Inc: MRO, RFC, SERC
- PJM Interconnection, LLC: RFC, SERC
- Southwest Power Pool: MRO, SPP

Historically, these four Planning Coordinators have provided capacity and load data to multiple Regional Entities. Consequently, this data has been artificially divided based on political boundaries that failed to accurately reflect the planning and operational properties of the bulk power system. This approach has reduced the accuracy of the resource and demand balance in these four Planning Coordinators that span over multiple Regional Entity boundaries. Taking these considerations into account, NERC instituted the following assessment areas presented in Figure I-1 in the *2011 Summer Reliability Assessment*.

**Figure I-1: 2012 Seasonal assessment areas[137]**




It is important to note that ISO/RTO boundaries are subject to change over time, due to consolidation of Load Serving Entities (LSE) and/or alterations in resource planning and acquisition arrangements. NERC's assessment areas will adjust accordingly and any potential changes will be identified in future reliability assessments.

The term "assessment area" has been applied consistently throughout this reliability assessment. However, the terms "Region," or "subregion" may also be used when the assessment area boundaries are synonymous to the Regional Entity or subregional boundaries.[138]

[137] For NERC's seasonal reliability assessments, WECC is divided into four subregions: Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), and California/México (CAMX). These seasonal subregions are structured around WECC's Reserve Sharing groups that experience similar demand patterns and employ similar operating practices. Additionally, the Western Reliability Coordination Offices collect actual demand data from the Reserve Sharing groups and leveraging the same footprints allows for consistent comparisons between demand forecasts and actual demands. NERC further divides the CAMX and NWPP subregions to provide additional data granularity for Canada, and México. For additional information, refer to the WECC section.

[138] For example, the ERCOT assessment area is synonymous to the ERCOT ISO and TRE Regional Entity, however, there is a PJM assessment area, but no PJM region within this assessment.

# Appendix II: Estimated Demand, Resources, and Reserve Margins

## Demand

NERC uses the following terms to categorize on-peak electricity demand:

- **Total Internal Demand**: The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system (forecast). Total Internal Demand includes adjustments for the indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electricity use, and all non-dispatchable Demand Response Programs. This value is used in the Planning Reserve Margin calculation.
- **Net Internal Demand**: Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce peak load.

## Capacity Resources

NERC uses the following terms to categorize capacity resources and transactions in seasonal assessments:

***Existing Capacity Resources***

- **Existing-Certain**: Existing generation resources available to operate and deliver power within or into the assessment area (or Region) during the period of assessment.
- **Existing-Other**: Existing generation resources that may be available to operate and deliver power within or into the assessment area (or subregion/Region) during the period of assessment, but may be curtailed or interrupted at any time for various reasons.
- **Existing, but Inoperable**: Existing portion of generation resources that are out of service and cannot be brought back into service to serve load during the period assessment.

***Existing Capacity Resources***

- **Future-Planned**: Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of assessment.
- **Future-Other**: Future generating resources that do not qualify in Future-Planned and are not included in the Conceptual category.

***Capacity Transactions***

- **Net Firm and Expected Transactions**: Firm and Expected Imports, minus Firm and Expected Exports; including all Firm contracts with a reasonable expectation to be implemented.

## Reserve Margins

Reserve Margins are capacity-based metrics and do not provide a comprehensive assessment of performance in energy-limited systems (*e.g.,* hydro capacity with limited water resources or systems with significant variable generation). Each capacity resource category (identified and explained in the previous section) is also used to calculate each different planning Reserve Margin.

Planning Reserve Margins for each assessment area are compared to the NERC Reference Margin Level, which is assigned for each NERC assessment area as defined and imposed by the corresponding Regional Entity, State Public Utility Commission, Provincial authority, or other delegating body. In the absence of a defined Reference Margin, NERC has applied 10 or 15 percent Reference Margin Levels for predominately hydro or thermal systems, respectively.

The NERC Reference Margin Level serves as a basis for determining whether more resources (*e.g.,* generation, Demand-Side Management, capacity transfers) may be needed within that Assessment Area.

Note 1: Demand and Supply forecasts were reported between February and August, 2011—depending on the assessment area.

Note 2: Values for both Total Internal Demand and Net Internal Demand for each assessment area represent on-peak projections.

Note 3: The WECC-US peak demands or resources do not necessarily equal the sums of the non-coincident WECC-US subregional peak demands or resources because of subregional monthly peak demand diversity. Similarly, the Western Interconnection peak demands or resources do not necessarily equal the sums of the non-coincident WECC-U.S., Canada, and México peak demands or resources. In addition, the subregional resource numbers include use of seasonal demand diversity between the winter-peaking northwest and the summer-peaking portions of the Western Interconnection.

# Appendix III: 2012 Summer Reliability Assessment Data and Information Request

The data request letter provided to the Regional Executives in January 2012 included the following instructions:

*2012 Summer Reliability Assessment* - Letter to Regional Entity Executives
http://www.nerc.com/docs/pc/ras/2012%20Summer%20Reliability%20Assessment%20Request%20Letter.doc

*2012 Summer Reliability Assessment* - Data Form
http://www.nerc.com/docs/pc/ras/ERO2012_SA_v4.xls

# Appendix IV: Reliability Concepts Used in this Report

## How NERC Defines Bulk Power System Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:[139]

- **Adequacy** — is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
- **Operating Reliability** — is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Regarding adequacy, system operators can and should take "controlled" actions or procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area). These actions include:

- Public appeals.
- Interruptible demand — demand that the end-use customer makes available to its LSE via contract or agreement for curtailment.[140]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5 percent).
- Rotating blackouts — the term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, rotating the outages among individual feeders.

Under the heading of Operating Reliability, are all other system disturbances that result in the unplanned and/or uncontrolled interruption of customer demand, regardless of cause. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as "cascading blackouts" – the uncontrolled successive loss of system elements triggered by an incident at any location.

## Planning Reserve Margin

The Planning Reserve Margin is a key metric that measures the flexibility to meeting customer demands and to handle the loss of one or more system elements as well as unforeseen, higher than expected demands. Specifically, the Planning Reserve Margin is the difference between the total resource capacity (which includes all generation physically available to provide deliverable power to load, transfers from neighboring area, and demand response resources designated as a supply-side resource) and system peak demand. It is the fraction of capacity available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen, higher than expected demands.

[139] Additional information regarding the Adequate Level of Reliability (ALR): http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

[140] Interruptible Demand (or Interruptible Load) is a term used in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, February 12, 2008, at http://www.nerc.com/files/Glossary_12Feb08.pdf.

Planning Reserve Margins are needed because a dependable supply of electricity is essential to the health, safety, and economic well-being of customers. Because electricity cannon be stored and must be produced at the instant it is used, there must always be some margin to allow for the repair and maintenance of equipment and the unavailability of resources.

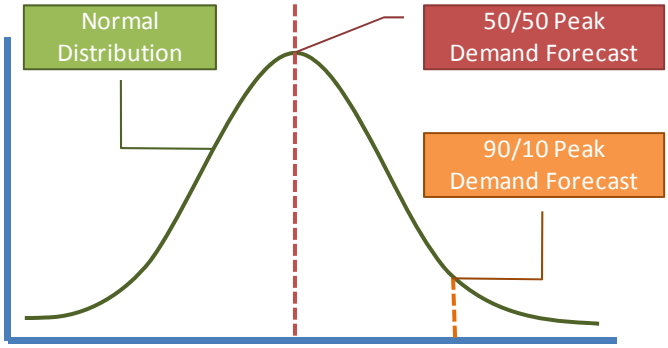
Planning Reserve Margins differ from Operating Reserve Margins in that Operating Reserve Margins are based on day-ahead and real-time system needs. Operating Reserve Margins, much like a shock absorber, are needed so that the electric system can respond and rebalance when sudden failures of equipment or sudden increases in customer demand occur. This type of margin must be instantly available so the electric system can remain in dynamic balance. Operating Reserves include such products as contingency reserves, spinning and non-spinning reserves, and regulation. Operating Reserve Margins also provide flexibility in operations, which allows the system operator to use the most economical plants to serve customer demand reducing fuel and operating costs.

## How Margins are Assessed

Proper planning, construction and operating of the system according to well established standards and guidelines assure adequate Planning and Operating Reserve Margins. Adequate Planning Reserve Margins depend on future electricity demands, completion of new generation and transmission facilities, retirement of generation, and performance of existing facilities. Assuring sufficient Planning Reserve Margins starts with a forecast of the future electricity requirements of residential, commercial, industrial, and governmental customers for up to 10 years or more in the future. Demand forecasts are continually reviewed and updated as economic conditions and other factors change.

For NERC reliability assessments, aggregated load forecasts are a single number or point; that is, the peak load or energy requirements for a given year are reported as a single specific value. In actuality, any forecast in itself is not a point or single value, but a probability distribution. The specific value represented in the assessment represents the probabilistic midpoint of the distribution such that the likelihood of exceeding it is equal to the likelihood of it not being reached (*i.e.*, a 50/50 forecast). While this has been understood within the industry, increasing interest in and attention to load forecasts by non-industry groups has led to frequent misunderstanding of the forecasts.

**Table IV-1: Example Load Forecast Distribution**




Furthermore, point or single value forecasts imply a greater degree of precision and certainty than is appropriate. The load or load growth actually experienced is a function of many factors over which the

electric power industry has little or no control – including the performance of local and national economies, the price of electricity, domestic versus foreign production of goods and services, industrial and other policies, changing technologies, federal and state legislation, and weather,. These and many other factors greatly influence the actual peak loads and energy requirements and make deviation from forecast values a common occurrence. In addition, comparing actual loads to point forecasts may be misleading since it does not appropriately express the wide variation of causative factors involved.

Both demand and supply forecasts are subject to uncertainties and risks. Changes in future economic growth can affect demand forecasts and supply forecasts can change if new facilities are delayed, postponed, or cancelled. Generation retirement uncertainties also exist in the supply forecast.

Uncertainty and risks are significant and must be factored into the planning process. Planning Reserve Margins provide the flexibility to mitigate and lower potential risks and uncertainties. The best way to deal with the risks and uncertainties in to increase flexibility by shortening lead-times to site, license, and construct facilities, and to keep open all supply and demand options for the future.

Upon calculating Planning Reserve Margins, a comparison to the NERC Reference Margin Level is made. Planning Reserve Margins for each assessment area are compared to the NERC Reference Margin Level, which is assigned for each NERC assessment area as defined and imposed by the corresponding Regional Entity, State Public Utility Commission, Provincial authority, or other delegating body. In the absence of a defined Reference Margin Level, NERC has applied either a 10 or 15 percent Reference Margin Level for predominately hydro or thermal systems, respectively. There are no NERC Reliability Standards which mandate maintaining a certain level of Planning Reserves. There is also no one appropriate margin for each utility, power pool, ISO/RTO, or Region. Operating conditions tend to be quite different because of such things as: changing weather conditions, characteristics of generation and transmission facilities, varying economic conditions, and custom demand patterns. Additionally, Planning Reserve Margins are not comparable across the difference assessment area.

## Developing Planning Reserve Margin Targets

As bulk power system planning has become increasingly complex, analytical techniques developed to assess resource adequacy have also become increasingly complex. Common to most methods is a sophisticated application of probability theory. Most techniques require assumptions which also derive from probability theory. For example, an estimate must be made of the probability that generating units modeled will be available when called upon to serve. Historical forced outages rates are used to forecast future rates, but obviously such an assumption is uncertain and the likelihood of higher or lower rates is inherent in the estimate.

Perhaps the most widely recognized index of reliability is Loss of Load Expectation (LOLE), also known as Loss of Load Probability (LOLP), which is ordinarily measured in days per year. These probabilistic values can then be used to determine what level of Planning Reserve Margin is needed in order to meet a "1 day in 10" loss of load. Like generation and demand distributions, the LOLE is also a distribution. The ability to serve load without Firm load interruption for every peak hour for ten years, except for one, is an industry-accepted, non-binding planning guideline. The resulting Planning Reserve Margin target is one that is probabilistically associated with the "1 day in 10" loss of load expectation (*i.e.*, LOLE = 0.1).

For some assessment areas, the methods are not as complex. For example, the FRCC Planning Reserve Margin target (NERC Reference Margin Level, is based a state-mandated flat percentage. For others, a target is applied based on generally accepted level using historical performance and engineering judgment.

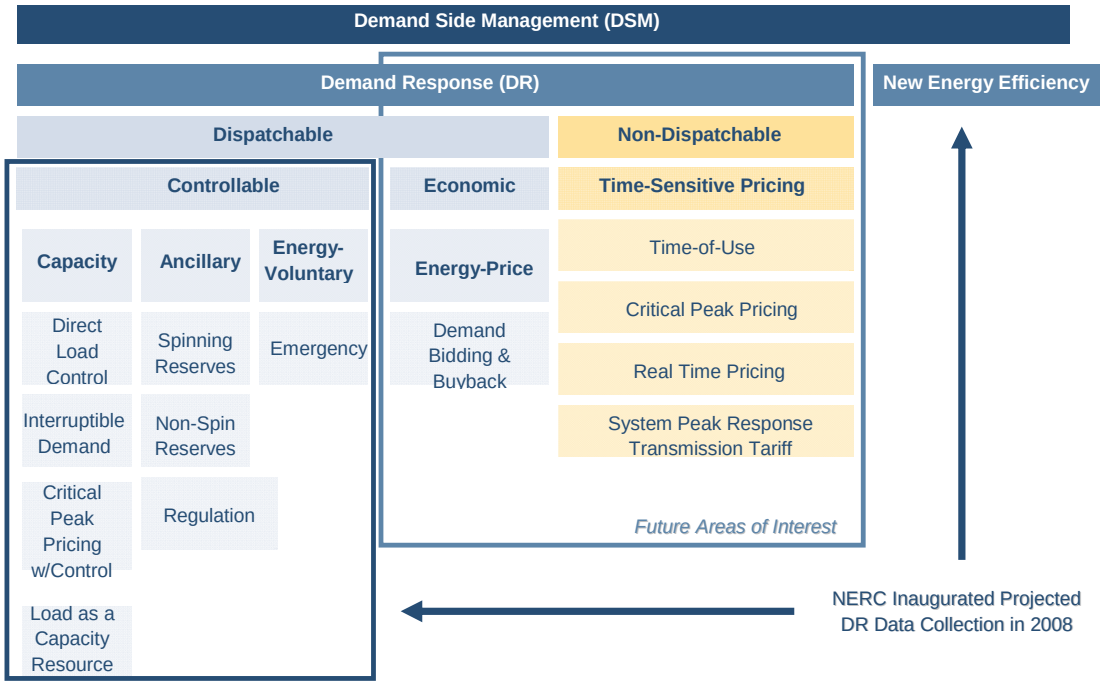
## Demand Response Concepts and Categorization

As the industry's use of Demand-Side Management (DSM) evolves, NERC's data collection and reliability assessments need to change highlighting programs and demand-side service offerings that have an impact on bulk system reliability.

NERC's seasonal and long-term reliability assessments currently assume projected Energy Efficiency programs are included in the Total Internal Demand forecasts, including adjustments for utility indirect Demand Response programs such as Conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates. DSM involves all activities or programs undertaken to influence the amount and timing of electricity use

Note the context of these activities and programs is DSM, rather than bulk power systems and, therefore, they are not meant to mirror those used in the system context. Figure A4-2 explains Demand Response categories are further defined in *Terms Used in this Report*.

**Figure A4-2: NERC Data Collection and Categorization for Demand-Side Management**



# Appendix V: Terms Used in this Report

**Ancillary** (Controllable Demand Response) — Demand-side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for nonperformance.

**Anticipated Capacity Resources** — Existing-Certain and Net Firm Transactions plus Future, Planned capacity resources plus Expected Imports, minus Expected Exports.

**Anticipated Reserve Margin (%)** — Deliverable Capacity Resources minus Net Internal Demand shown as a percent of Net Internal Demand.

**Capacity** (Controllable Demand Response) — Demand-side resource displaces or augments generation for planning and/or operating resource adequacy; penalties are assessed for nonperformance.

**Capacity Categories** — *See **Existing Generation Resources, Future Generation Resources,** and **Conceptual Generation Resources***.

**Capacity Margin (%)** — *See **Deliverable Capacity Margin (%)** and **Prospective Capacity Margin (%)***. Roughly, Capacity minus Demand, divided by Capacity or (Capacity-Demand)/Capacity. Replaced in 2009 with *Reserve Margin(s) (%)* for NERC Assessments.

***Conceptual* Generation Resources** — This category includes generation resources that are not included in *Existing Generation Resources* or *Future Generation Resources*, but have been identified and/or announced on a resource planning basis through one or more of the following sources:

- Corporate announcement
- Entered into or is in the early stages of an approval process
- Is in a generator interconnection (or other) queue for study
- "Place-holder" generation for use in modeling, such as generator modeling needed to support NERC Standard TPL analysis, as well as, integrated resource planning resource studies.

Resources included in this category may be adjusted using a confidence factor (%) to reflect uncertainties associated with siting, project development or queue position.

**Conservation** — *See **Energy Conservation***

**Contractually Interruptible (Curtailable)** (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-side management achieved by a customer reducing its load upon notification from a control center. The interruption must be mandatory at times of system emergency. Curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Entity's seasonal peak. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

**Controllable** (Demand Response) — Dispatchable Demand Response, demand-side resources used to supplement generation resources resolving system and/or local capacity constraints.

**Critical Peak Pricing (CPP)** (Non-dispatchable Time-Sensitive Pricing Demand Response) — Rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market

prices or system contingencies by imposing a pre-specified high rate for a limited number of days or hours.

**Critical Peak Pricing (CPP) with Control** (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-side management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

**Curtailable** — *See **Contractually Interruptible***

**Demand** — *See **Net Internal Demand, Total Internal Demand***

**Demand Bidding & Buyback** (Controllable Energy-Price Demand Response) — Demand-side resource that enable large consumers to offer specific bid or posted prices for specified load reductions. Customers stay at fixed rates, but receive higher payments for load reductions when the wholesale prices are high.

**Demand Response** — Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

**Derate** (Capacity) — The amount of capacity that is expected to be unavailable on seasonal peak.

**Direct Control Load Management (DCLM) or Direct Load Control (DLC)** (Controllable Capacity Demand Response) — 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.[141]

**Dispatchable** (Demand Response) — Demand-side resource curtails according to instruction from a control center.

**Disturbance Classification Scale** — *See **NERC's Bulk Power System Disturbance Classification Scale***

**Disturbance Event** — *See **NERC's Bulk Power System Disturbance Classification Scale***

**Economic** (Controllable Demand Response) — Demand-side resource that is dispatched based on an economic decision.

**Emergency** (Controllable Energy-Voluntary Demand Response) — Demand-side resource curtails during system and/or local capacity constraints.

**Energy Conservation** — The practice of decreasing the quantity of energy used.

**Energy Efficiency** — Permanent changes to electricity use through replacement with more efficient end-use devices or more effective operation of existing devices. Generally, it results in reduced consumption across all hours rather than event-driven targeted load reductions.

[141] DCLM is a term defined in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, Updated April 20, 2009 www.nerc.com/files/Glossary_2009April20.pdf

**Energy Emergency Alert Levels** — The categories for capacity and emergency events based on Reliability Standard EOP—002-0:

- Level 1 — All available resources in use.
  - Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet Firm load, Firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and non-Firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
- Level 2 — Load management procedures in effect.
  - Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
  - Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of Firm load commitments. When time permits, these procedures may include, but are not limited to: Public appeals to reduce demand, Voltage reduction, Interruption of non-Firm end use loads in accordance with applicable contracts, Demand-side management, and Utility load Conservation measures.
- Level 3 — Firm load interruption imminent or in progress.
  - Balancing Authority or Load Serving Entity foresees or has implemented Firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Level (Alert) 2, is only accessible with actions taken to increase transmission transfer capabilities.

**Energy Only** (Capacity) — energy only resources are generally generating resources that are designated as energy only resources or have elected to be classified as energy only resources and may include generating capacity that can be delivered within the area but may be recallable to another area.

**Energy-Price** (Controllable Economic Demand Response) — Demand-side resource that reduces energy for incentives.

**Energy-Voluntary** (Controllable Demand Response) — Demand-side resource curtails voluntarily when offered the opportunity to do so for compensation, but nonperformance is not penalized.

**Existing-Certain** (Existing Generation Resources) — Existing generation resources available to operate and deliver power within or into the Region during the period of analysis in the assessment. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes, but is not limited to the following:

1. Contracted (or Firm) or other similar resource confirmed able to serve load during the period of analysis in the assessment.
2. Where organized markets exist, designated market resource[142] that is eligible to bid into a market or has been designated as a Firm network resource.

[142] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

3. Network Resource[143], as that term is used for FERC *pro forma* or other regulatory approved tariffs.
4. Energy only resources[144] confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[145]
5. Capacity resources that cannot be sold elsewhere.
6. Other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed[146] during the period of analysis in the assessment.

**Existing-Certain & Net Firm Transactions** — Existing-Certain capacity resources plus Firm Imports, minus Firm Exports. (MW)

**Existing-Certain and Net Firm Transactions (%)** (Margin Category) — Existing-Certain & Net Firm Transactions minus Net Internal Demand shown as a percent of Net Internal Demand.

**Existing Generation Resources** — *See **Existing-Certain**, **Existing-Other**, **Existing-Inoperable***.

**Existing-Inoperable** (Existing Generation Resources) — This category contains the existing portion of generation resources that are out-of-service and cannot be brought back into service to serve load during the period of analysis in the assessment. However, this category can include inoperable resources that could return to service at some point in the future. This value may vary for future seasons and can be reported as zero. This includes all existing generation not included in categories *Existing-Certain* or *Existing-Other*, but is not limited to, the following:

1. Mothballed generation (that cannot be returned to service for the period of the assessment).
2. Other existing but out-of-service generation (that cannot be returned to service for the period of the assessment).
3. This category does not include behind-the-meter generation or non-connected emergency generators that normally do not run.
4. This category does not include partially dismantled units that are not forecasted to return to service.

**Existing-Other** (Existing Generation Resources) — Existing generation resources that may be available to operate and deliver power within or into the Region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in *Existing-Certain*. This category includes, but is not limited to the following:

- A resource with non-Firm or other similar transmission arrangements.

[143] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[144] Energy only resources are generally generating resources that are designated as energy only resources or have elected to be classified as energy only resources and may include generating capacity that can be delivered within the area but may be recallable to another area (Source: 2008 EIA 411 document OMB No. 1905-0129)." Note: Other than wind and solar energy, WECC does not have energy only resources that are counted towards capacity.

[145] Energy only resources with transmission service constraints are to be considered in category Existing-Other.

[146] Energy only resources with transmission service constraints are to be considered in category Existing-Other.

- Energy only resources that have been confirmed able to serve load for any reason during the period of analysis in the assessment, but may be curtailed for any reason.
- Mothballed generation (that may be returned to service for the period of the assessment).
- Portions of variable generation not counted in the Existing-Certain category (*e.g.,* wind, solar, etc. that may not be available or derated during the assessment period).
- Hydro generation not counted as Existing-Certain or derated.
- Generation resources constrained for other reasons.

**Expected** (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Expected implies that a contract has not been executed, but in negotiation, projected or other. These Purchases or Sales are expected to be Firm.
2. Expected Purchases and Sales should be considered in the reliability assessments.

**Firm** (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Firm implies a contract has been signed and may be recallable.
2. Firm Purchases and Sales should be reported in the reliability assessments. The purchasing entity should count such capacity in margin calculations. Care should be taken by both entities to appropriate report the generating capacity that is subject to such Firm contract.

**Future Generation Resources** (*See also* ***Future-Planned*** *and* ***Future-Other***) — This category includes generation resources the reporting entity has a reasonable expectation of coming online during the period of the assessment. As such, to qualify in either of the Future categories, the resource must have achieved one or more of these milestones:

1. Construction has started.
2. Regulatory permits being approved, any one of the following:
    a. Site permit
    b. Construction permit
    c. Environmental permit
3. Regulatory approval has been received to be in the rate base.
4. Approved power purchase agreement.
5. Approved and/or designated as a resource by a market operator.

**Future-Other** (Future Generation Resources) — This category includes future generating resources that do not qualify in Future-Planned and are not included in the Conceptual category. This category includes, but is not limited to, generation resources during the period of analysis in the assessment that may:

1. Be curtailed or interrupted at any time for any reason.
2. Energy only resources that may not be able to serve load during the period of analysis in the assessment.
3. Variable generation not counted in the Future-Planned category or may not be available or is derated during the assessment period.
4. Hydro generation not counted in category Future-Planned or derated.

5. Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position.

**Future-Planned** (Future Generation Resources) — Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of analysis in the assessment. This category includes, but is not limited to, the following:

1. Contracted (or Firm) or other similar resource.
2. Where organized markets exist, designated market resource[147] that is eligible to bid into a market or has been designated as a Firm network resource.
3. Network Resource,[148] as that term is used for FERC pro forma or other regulatory approved tariffs.
4. Energy only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[149]
5. Where applicable, included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve.

**Load as a Capacity Resource** (Controllable Capacity Demand Response) — A resource that commits to pre-specified load reductions when system contingencies arise.[150]

**NERC's Bulk Power System Disturbance Classification Scale**[151] — The NERC Event Analysis program breaks events into two general classifications: Operating Security Events and Resource Adequacy Events. Each event is categorized during the triage process to help NERC and Regional Event Analysis staff to determine an appropriate level of analysis or review. Similar to scales used to rank large weather systems and storms, NERC's Bulk Power System Event Classification Scale is designed to classify bulk power system disturbances by severity, size, and impact to the general public.

**Operating Security Events** — Operating reliability events are those that significantly affect the integrity of interconnected system operations. They are divided into 5 categories to take into account different system impacts.

- **Category 1**: An event results in any or combination of the following actions:
    a. The loss of a bulk power transmission component beyond recognized criteria,*i.e.,* single-phase line-to-ground fault with delayed clearing, line tripping due to growing trees, etc.
    b. Frequency below the Low Frequency Trigger Limit (FTL) more than 5 minutes.
    c. Frequency above the High FTL more than 5 minutes.
    d. Partial loss of dc converter station (mono-polar operation).

[147] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[148] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[149] Energy only resources with transmission service constraints are to be considered in category Future, Other.

[150] These resources are not limited to being dispatched during system contingencies. They may be subject to economic dispatch from wholesale balancing authorities or through a retail tariff and bilateral arrangements with a third-party curtailments service provider. Additionally, this capacity may be used to meet resource adequacy obligations when determining panning Reserve Margins.

[151] http://www.nerc.com/page.php?cid=5%7C252.

e. "Clear-Sky" Inter-area oscillations.
f. Intended and controlled system separation by proper Special Protection Schemes / Remedial Action Schemes (SPS/RAS) action of Alberta from the Western Interconnection, New Brunswick from New England, or Florida from the Eastern Interconnection.
g. Unintended system separation resulting in an island of a combination of load and generation of 20 MW to 300 MW.
h. Proper SPS/RAS actuation resulting in load loss of 100 MW to 500 MW.

- **Category 2**: An event results in any or combination of the following actions:

a. Complete loss of dc converter station.
b. The loss of multiple bulk power transmission components.
c. The loss of an entire switching station (all lines, 100 kV or above).
d. The loss of an entire generation station of 5 or more generators (aggregate stations of 75 MW or higher).
e. Loss of off-site power (LOOP) to a nuclear generating station.
f. The loss of load of 300 MW to 500 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
g. Proper SPS/RAS, UFLS, or UVLS actuation that results in loss of load of 500 MW or greater.
h. The loss of generation (between 1,000 and 2,000 MW in the Eastern Interconnection or Western Interconnection and between 500 MW and 1,000 MW in the Texas or Québec Interconnections).
i. The planned automatic rejection of generation through special protection schemes (SPS) or remedial action schemes (RAS) of less than 3,000 MW in the Western Interconnection, or less than 1,500 MW in the Eastern, Texas, and Québec Interconnections.
j. Unintended system separation resulting in an island of a combination of load and generation of 301 MW to 5,000 MW.
k. SPS/RAS misoperation.

- **Category 3**: An event results in any or combination of the following actions:

a. The loss of load from 500 MW to 1,000 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
b. The unplanned loss of generation (excluding automatic rejection of generation through SPS/RAS) of 2,000 MW or more in the Eastern Interconnection or Western Interconnection, and 1,000 MW or more in the Texas or Québec Interconnections.
c. Unintended system separation resulting in an island of a combination of load and generation of 5,001 MW to 10,000 MW.

- **Category 4**: An event results in any or combination of the following actions:

a. The loss of load from 1,000 MW to 9,999 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
b. Unintended system separation resulting in an island of a combination of load and generation of more than 10,000 MW.

- **Category 5**: An event results in any or combination of the following actions:

a. The loss of load of 10,000 MW or more.
b. The loss of generation of 10,000 MW or more.

**Resource Adequacy Events** — Adequacy events are divided into three categories based on Standard EOP—002-0 (Capacity and Energy Emergencies).

- **Category A1**: No disturbance events and all available resources in use.
  a. Required Operating Reserves cannot be sustained.
  b. Non-Firm wholesale energy sales have been curtailed.
- **Category A2**: Load management procedures in effect.
  a. Public appeals to reduce demand.
  b. Voltage reduction.
  c. Interruption of non-Firm end per contracts.
  d. Demand-side management.
  e. Utility load Conservation measures.
- **Category A3**: Firm load interruption imminent or in progress.

**(NERC) Reference Margin Level (%)** — Either the Target Reserve Margin provided by the Region/subregion or NERC assigned based on capacity mix (*i.e.*, thermal/hydro). Each Region/subregion may have their own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the Regional/subregional Target Reserve Margin level is adopted as the NERC Reference Margin Level. If not, NERC assigned 15 percent Reserve Margin for predominately thermal systems and for predominately hydro systems, 10 percent.

**Net Internal Demand** — Equals the Total Internal Demand reduced by the total Dispatchable, Controllable, Capacity Demand Response equaling the sum of Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resource.

**Non-dispatchable** (Demand Response) — Demand-side resource curtails according to tariff structure, not instruction from a control center.

**Non-Firm** (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including:

1. Non-Firm implies a non-Firm contract has been signed.
2. Non-Firm Purchases and Sales should not be considered in the reliability assessments.

**Non-Spin Reserves** (Controllable Ancillary Demand Response) — Demand-side resource not connected to the system but capable of serving demand within a specified time.

**On-Peak** (Capacity) — The amount of capacity that is expected to be available on seasonal peak.

**Operating Reliability Events Categories** — *See* ***NERC's Bulk Power System Disturbance Classification Scale***

**Prospective Capacity Reserve Margin (%)** — Prospective Capacity Resources minus Net Internal Demand shown as a percent of Net Internal Demand.

**Prospective Capacity Resources (MW)** — Anticipated Capacity Resources plus Existing-Other capacity resources, plus Future-Other capacity resources.

**Provisional** (Transaction Category) — A category of Purchases/Imports and Sales/Exports with contracts. Provisional implies that the transactions are under study, but negotiations have not begun. These Purchases and Sales are expected to be provisionally Firm.

**Purchases/Imports** — *See **Transaction Categories***

**Real-Time Pricing (RTP)** (Non-dispatchable Time-Sensitive Pricing Demand Response) — Rate and price structure in which the price for electricity typically fluctuates to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.

**Reference Margin Level** — *See **NERC Reference Margin Level***

**Regulation** (Controllable Ancillary Demand Response) — Demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin.

**Renewable Energy** — The United States Department of Energy, Energy Efficiency & Renewable Energy glossary defines "Renewable Energy" as "energy derived from resources that are regenerative or for all practical purposes cannot be depleted. Types of renewable energy resources include moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy. Municipal solid waste (MSW) is also considered to be a renewable energy resource."[152] The government of Canada has a similar definition.[153] Variable generation is a subset of Renewable Energy — See ***Variable Generation***.

**Renewables** — *See **Renewable Energy***

**Reserve Margin (%)** — *See **Deliverable Capacity Reserve Margin (%)** and **Prospective Capacity Reserve Margin (%)**.* Roughly, Capacity minus Demand, divided by Demand or (Capacity-Demand)/Demand. Replaced *Capacity Margin(s) (%)* for NERC Assessments in 2009.

**Resource Adequacy Events** — *See **NERC's Bulk Power System Disturbance Classification Scale***

**Sales/Exports Contracts** — *See Transaction Categories*

**Spinning/Responsive Reserves** (Controllable Ancillary Demand Response) — Demand-side resources that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event.

**System Peak Response Transmission Tariff** (Non-dispatchable Time-Sensitive Pricing Demand Response) — The rate and/or price structure in which interval metered customers reduce load during coincident peaks as a way of reducing transmission charges.

**Target Reserve Margin (%)** — Established target for Reserve Margin by the Region or subregion. Not all Regions report a Target Reserve Margin. The NERC Reference Margin Level is used in those cases where a Target Reserve Margin is not provided.

**Total Internal Demand** — The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for

[152] http://www1.eere.energy.gov/site_administration/glossary.html#R.
[153] http://www.cleanenergy.gc.ca/index.cfm?action=faq.summary.

station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electric energy use, all non-dispatchable Demand Response programs (such as Time-of-Use, Critical Peak Pricing, Real-time Pricing and System Peak Response Transmission Tariffs) and some dispatchable Demand Response (such as Demand Bidding and Buy-Back). Adjustments for controllable Demand Response should not be incorporated in this value.

**Time-of-Use (TOU)** (Non-dispatchable Time-Sensitive Pricing Demand Response) — Rate and/or price structures with different unit prices for use during different blocks of time.

**Time-Sensitive Pricing** (Non-dispatchable Demand Response) — Retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify consumption behavior during high-cost and/or peak periods.

**Transaction Categories** (*See also **Firm, Expected and Provisional**)* — Contracts for Capacity are defined as an agreement between two or more parties for the Purchase and Sale of generating capacity. Purchase contracts refer to imported capacity that is transmitted from an outside Region or subregion to the reporting Region or subregion. Sales contracts refer to exported capacity that is transmitted from the reporting Region or subregion to an outside Region or subregion. For example, if a resource subject to a contract is located in one Region and sold to another Region, the Region in which the resource is located reports the capacity of the resource and reports the sale of such capacity that is being sold to the outside Region. The purchasing Region reports such capacity as a purchase, but does not report the capacity of such resource. Transmission must be available for all reported Purchases and Sales.

**Transmission-Limited Resources** — The amount of transmission-limited generation resources that have known physical deliverability limitations to serve load within the Region. If capacity is limited by both studied transmission limitations and generator derates, the generator derates take precedence. For example, a 100 MW wind farm with a wind capacity variation reduction of 50 MW and a transmission limitation of 60 MW would take the 50 MW wind variation reduction first and list 10 MW in the transmission limitation.

**Transmission Loading Relief (TLR) Levels** — Various levels of the TLR Procedure from Reliability Standard IRO—006-4 — Reliability Coordination — Transmission Loading Relief:

- TLR Level 1 — Notify Reliability Coordinators of potential SOL or IROL Violations
- TLR Level 2 — Hold transfers at present level to prevent SOL or IROL Violations
- TLR Level 3a — Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service
- TLR Level 3b — Curtail Interchange Transactions using Non-Firm Transmission Service Arrangements to mitigate a SOL or IROL Violation
- TLR Level 4 — Reconfigure Transmission
- TLR Level 5a — Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service

- TLR Level 5b — Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation
- TLR Level 6 — Emergency Procedures
- TLR Level 0 — TLR concluded

**Transmission Status Categories** — Transmission additions were categorized using the following criteria:

- Under Construction: Construction of the line has begun
- Planned (any of the following)"
- Permits have been approved to proceed
- Design is complete
- Needed in order to meet a regulatory requirement
- Conceptual (any of the following)
- A line projected in the transmission plan
- A line that is required to meet a NERC TPL Standard or included in a powerflow model and cannot be categorized as "Under Construction" or "Planned"
- Projected transmission lines that are not "Under Construction" or "Planned"

**Variable Generation** — Variable generation technologies generally refer to generating technologies whose primary energy source varies over time and cannot reasonably be stored to address such variation.[154] Variable generation sources which include wind, solar, ocean and some hydro generation resources are all renewable based. Variable generation in this report refers only to wind and solar resources. There are two major attributes of a variable generator that distinguish it from conventional forms of generation and may impact the bulk power system planning and operations: variability and uncertainty.

**Variability** — The output of variable generation changes according to the availability of the primary fuel (wind, sunlight and moving water) resulting in fluctuations in the plant output on all time scales.

**Uncertainty** — The magnitude and timing of variable generation output is less predictable than for conventional generation.

[154] http://www.nerc.com/files/IVGTF_Report_041609.pdf.

# Appendix VI: Abbreviations Used in this Report

| | |
|---|---|
| A/C | Air Conditioning |
| AEP | American Electric Power |
| AFC | Available Flowgate Capability |
| ASM | Ancillary Services Market |
| ATCLLC | American Transmission Company |
| ATR | AREA Transmission Review (of NYISO) |
| AWEA | American Wind Energy Association |
| BA | Balancing Authorities |
| BASN | Basin (subregion of WECC) |
| BCF | Billion cubic feet |
| BCFD | Billion cubic feet per day |
| CALN | California-North (subregion of WECC) |
| CALS | California-South (subregion of WECC) |
| CANW | WECC-Canada (subregion of WECC) |
| CFL | Compact Fluorescent Light |
| CMPA | California-Mexico Power Area |
| COI | California-Oregon Intertie |
| COS | Coordinated Outage (transmission) System |
| CPUC | California Public Utilities Commission |
| CRO | Contingency Reserve Obligation |
| CRP | Curtailable Rate Program (Manitoba Hydro) |
| CRPP | Comprehensive Reliability Planning Process (of NYISO) |
| DADRP | Day-Ahead Demand Response Program |
| dc | Direct Current |
| DCLM | Direct Controlled Load Management |
| DFW | Dallas/Fort Worth |
| DLC | Direct Load Control |
| DOE | U.S. Department of Energy |
| DSG | Dynamics Study Group |
| DSI | Direct-served Industry |
| DSM | Demand-Side Management |
| DSW | Desert Southwest (subregion of WECC) |
| DVAR | D-VAR® reactive power compensation system |
| EDRP | Emergency Demand Response Program |
| EE | Energy Efficiency |
| EEA | Energy Emergency Alert |
| EECP | Emergency Electric Curtailment Plan |
| EIA | Energy Information Agency (of DOE) |
| EILS | Emergency Interruptible Load Service (of ERCOT) |
| EISA | Energy Independence and Security Act of 2007 (USA) |
| ELCC | Effective Load-carrying Capability |
| EMTP | Electromagnetic Transient Program |
| ENS | Energy Not Served |

| | |
|---|---|
| EOP | Emergency Operating Procedure |
| ERAG | Eastern Interconnection Reliability Assessment Group |
| ERCOT | Electric Reliability Council of Texas |
| ERO | Electric Reliability Organization |
| FCITC | First Contingency Incremental Transfer Capability |
| FCM | Forward Capacity Market |
| FERC | U.S. Federal Energy Regulatory Commission |
| FP | *Future-Planned* |
| FO | *Future-Other* |
| FRCC | Florida Reliability Coordinating Council |
| GADS | Generating Availability Data System |
| GDP | Gross Domestic Product |
| GGGS | Gerald Gentleman Station Stability |
| GHG | Greenhouse Gas |
| GRSP | Generation Reserve Sharing Pool (of MAPP) |
| GTA | Greater Toronto Area |
| GWh | Gigawatt hours |
| HDD | Heating Degree Days |
| HVac | Heating, Ventilating, and Air Conditioning |
| IA | Interchange Authority |
| ICAP | Installed Capacity |
| ICR | Installed Capacity Requirement |
| IESO | Independent Electric System Operator (in Ontario) |
| IOU | Investor Owned Utility |
| IPL/NRI | International Power Line/Northeast Reliability Interconnect Project |
| IPSI | Integrated Power System Plan |
| IRM | Installed Reserve Margin |
| IROL | Interconnection Reliability Operating Limit |
| IRP | Integrated Resource Plan |
| ISO | Independent System Operator |
| ISO-NE | New England Independent System Operator |
| kV | Kilovolts (one thousand volts) |
| LaaRs | Loads acting as a Resource |
| LCR | Locational Installed Capacity Requirements |
| LDC | Load Duration Curve |
| LFU | Load Forecast Uncertainty |
| LNG | Liquefied Natural Gas |
| LOLE | Loss of Load Expectation |
| LOLP | Loss Of Load Probability |
| LOOP | Loss of off-site power |
| LRP | Long Range Plan |
| LSE | Load-serving Entities |
| LTRA | Long-Term Reliability Assessment |
| LTSG | Long-term Study Group |
| MAAC | Mid-Atlantic Area Council |

| | |
|---|---|
| Maf | Million acre-feet |
| MAIN | Mid-America Interconnected Network, Inc. |
| MAPP | Mid-Continent Area Power Pool |
| MCRSG | Midwest Contingency Reserve Sharing Group |
| MEXW | WECC-Mexico (subregion of WECC) |
| MISO | Midwest Independent Transmission System Operator |
| MPRP | Maine Power Reliability Program |
| MRO | Midwest Reliability Organization |
| MVA | Megavolt amperes |
| MVAr | Mega-VArs |
| MW | Megawatts (millions of watts) |
| MWEX | Minnesota Wisconsin Export |
| NB | New Brunswick |
| NBSO | New Brunswick System Operator |
| NDEX | North Dakota Export Stability Interface |
| NEEWS | New England East West Solution |
| NERC | North American Electric Reliability Corporation |
| NIETC | National Interest Electric Transmission Corridor |
| NOPSG | Northwest Operation and Planning Study Group |
| NORW | Northwest (subregion of WECC) |
| NPCC | Northeast Power Coordinating Council |
| NPDES | National Pollutant Discharge Elimination System |
| NPPD | Nebraska Public Power District |
| NSPI | Nova Scotia Power Inc. |
| NTSG | Near-term Study Group |
| NWPP | Northwest Power Pool Area (subregion of WECC) |
| NYISO | New York Independent System Operator |
| NYPA | New York Planning Authority |
| NYRSC | New York State Reliability Council, LLC |
| NYSERDA | New York State Energy and Research Development Agency |
| OASIS | Open Access Same Time Information Service |
| OATT | Open Access Transmission Tariff |
| OP | Operating Procedure |
| OPA | Ontario Power Authority |
| OPPD | Omaha Public Power District |
| ORWG | Operating Reliability Working Group |
| OTC | Operating Transfer Capability |
| OVEC | Ohio Valley Electric Corporation |
| PA | Planning Authority |
| PACE | PacifiCorp East |
| PAR | Phase Angle Regulators |
| PC | NERC Planning Committee |
| PCAP | Pre-Contingency Action Plans |
| PCC | Planning Coordination Committee (of WECC) |
| PJM | PJM Interconnection |

| | |
|---|---|
| PRB | Powder River Basin |
| PRC | Public Regulation Commission |
| PRSG | Planned Reserve Sharing Group |
| PSA | Power Supply Assessment |
| PUCN | Public Utilities Commission of Nevada |
| QSE | Qualified Scheduling Entities |
| RA | Resource Adequacy |
| RAP | Remedial Action Plan |
| RAR | Resource Adequacy Requirement |
| RAS | Reliability Assessment Subcommittee of NERC Planning Committee |
| RC | Reliability Coordinator |
| RCC | Reliability Coordinating Committee |
| RFC | ReliabilityFirst Corporation |
| RFP | Request For Proposal |
| RGGI | Regional Greenhouse Gas Initiative |
| RIS | Resource Issues Subcommittee of NERC Planning Committee |
| RMR | Reliability Must Run |
| RMRG | Rocky Mountain Reserve Group |
| ROCK | Rockies (subregion of WECC) |
| RP | Reliability Planner |
| RPM | Reliability Pricing Mode |
| RRS | Reliability Review Subcommittee |
| RSG | Reserve Sharing Group |
| RTEP | Regional Transmission Expansion Plan (for PJM) |
| RTO | Regional Transmission Organization |
| RTP | Real-time Pricing |
| RTWG | Renewable Technologies Working Group |
| SA | Security Analysis |
| SasKPower | Saskatchewan Power Corp. |
| SCADA | Supervisory Control and Data Acquisition |
| SCC | Seasonal Claimed Capability |
| SCD | Security Constrained Dispatch |
| SCDWG | Short Circuit Database Working Group |
| SCEC | State Capacity Emergency Coordinator (of FRCC) |
| SCR | Special Case Resources |
| SEMA | Southeastern Massachusetts |
| SEPA | State Environmental Protection Administration |
| SERC | SERC Reliability Corporation |
| SMUD | Sacramento Municipal Utility District |
| SOL | System Operating Limits |
| SPP | Southwest Power Pool |
| SPS | Special Protection System |
| SPS/RAS | Special Protection Schemes / Remedial Action Schemes |
| SRIS | System Reliability Impact Studies |
| SRWG | System Review Working Group |

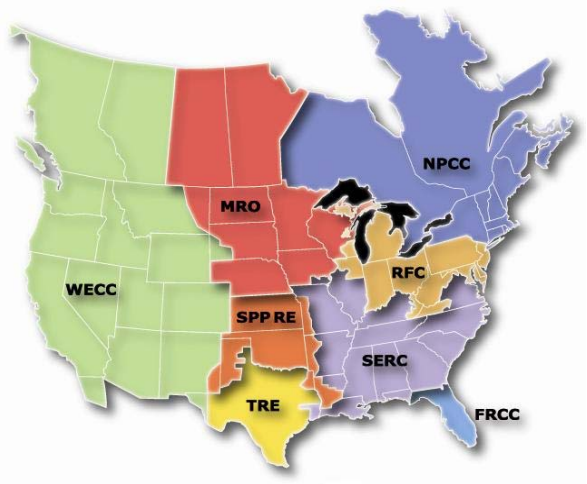
| | |
|---|---|
| STATCOM | Static Synchronous Compensator |
| STEP | SPP Transmission Expansion Plan |
| SVC | Static VAr Compensation |
| TCF | Trillion Cubic Feet |
| TFCP | Task Force on Coordination of Planning |
| THI | Temperature Humidity Index |
| TIC | Total Import Capability |
| TID | Total Internal Demand |
| TLR | Transmission Loading Relief |
| TOP | Transmission Operator |
| TPL | Transmission Planning |
| TRE | Texas Regional Entity |
| TRM | Transmission Reliability Margins |
| TS | Transformer Station |
| TSP | Transmission Service Provider |
| TSS | Technical Studies Subcommittee |
| TVA | Tennessee Valley Authority |
| USBRLC | United States Bureau of Reclamation Lower Colorado Region |
| UFLS | Under Frequency Load Shedding Schemes |
| UVLS | Under Voltage Load-Shedding |
| VAr | Voltampere reactive |
| VACAR | Virginia and Carolinas (subregion of SERC) |
| VSAT | Voltage Stability Assessment Tool |
| WALC | Western Area Lower Colorado |
| WECC | Western Electricity Coordinating Council |
| WTHI | Weighted Temperature-Humidity Index |
| WUMS | Wisconsin-Upper Michigan Systems |

# Reliability Assessments Subcommittee

| Name | Position | Represents | Job Title | Organization |
|---|---|---|---|---|
| Vince Ordax | Chairman | FRCC | Manager of Planning | Florida Reliability Coordinating Council |
| Curtis Crews | Vice Chairman | TRE | Lead Reliability Assessment Engineer | Texas Reliability Entity, Inc. |
| Justin Michlig | Member | MRO | Transmission Planning Specialty Engineer | Xcel Energy, Inc. |
| William B. Kunkel | Member | MRO | Senior Engineer | Midwest Reliability Organization |
| John Lawhorn | Member | MRO | Senior Director, Regulatory and Economic Studies | Midwest ISO, Inc. |
| Madhuri Kandukuri | Member | MRO | Senior Engineer , Regulatory and Economic Studies | Midwest ISO, Inc. |
| Josh Collins | Member | MRO | Engineer I | Midwest ISO, Inc. |
| Salva R. Andiappan | Member | MRO | Manager- Modeling and Reliability Assessments | Midwest Reliability Organization |
| Rao Konidena | Member | MRO | Manager, Resource Forcasting | Midwest ISO, Inc. |
| Bagen Bagen | Member | MRO | Exploratory Studies Engineer | Manitoba Hydro |
| Peter Wong | Member | NPCC | Manager, Resource Adequacy | ISO New England, Inc. |
| Kevan L Jefferies | Member | NPCC | Manager - Market Forecasts and Modeling | Ontario Power Generation Inc. |
| Mark J Kuras | Member | RFC | Senior Lead Engineer | PJM Interconnection, L.L.C. |
| Bob Mariotti | Member | RFC | Supervisor - Short Term Forecasting | DTE Energy |
| Glenn P Catenacci | Member | RFC | Principal Staff Engineer | Public Service Electric and Gas Co. |
| Esam A.F. Khadr | Member | RFC | Director Electric Delivery Planning | Public Service Electric and Gas Co. |
| Mohammed Ahmed | Member | RFC | Manager, East Tranining Planning | American Electric Power Company |
| Hubert C Young | Member | SERC | Manager of Transmission Planning | South Carolina Electric & Gas Co. |
| K. R. Chakravarthi | Member | SERC | Manager, Interconnection and Special Studies | Southern Company Services, Inc |
| Gary S. Brinkworth | Member | SERC | Senior Manager | Tennessee Valley Authority |
| David Kelley | Member | SPP | Manager, Interregional Coordination | Southwest Power Pool Inc. |
| James Useldinger | Member | SPP | Manager, T&D System Operations | Kansas City Power & Light Co. |
| Warren Lasher | Member | TRE | Manager, System Assessment | Electric Reliability Council of Texas, Inc. |

| Name | Position | Represents | Job Title | Organization |
|---|---|---|---|---|
| Tina G. Ko | Member | WECC | Manager, Resources & Loads Analysis | Bonneville Power Administration |
| James Leigh-Kendall | Member | WECC | Manager, Reliability Compliance and Coordination | Sacramento Municipal Utility District |
| Jerry D. Rust | OC | OC Liason | President | Northwest Power Pool Corporation |
| Sedina Eric | Observer | Federa | Electrical Engineer | Federal Energy Regulatory Commission |
| David J Burnham | Observer | Federa | Electrical Engineer | Federal Energy Regulatory Commission |
| Patricia Hoffman | Observer | Federa | Assistant Secretary | U.S. Department of Energy |
| Maria A. Hanley | Observer | Federa | Program Analyst | U.S. Department of Energy |
| Erik Paul Shuster | Observer | Federa | Engineer | U.S. Department of Energy |
| Peter Balash | Observer | Federa | Senior Economist | U.S. Department of Energy |
| C. Richard Bozek | Observer | Trades | Director, Environmental Policy | Edison Electric Institute |
| Daniel Brooks | Observer | Trades | Manager, Power Delivery System Studies | Electric Power Research Institute |

# Regional Entity Reliability Assessment Representatives




| | |
|---|---|
| **FRCC** | Florida Reliability Coordinating Council |
| **MRO** | Midwest Reliability Organization |
| **NPCC** | Northeast Power Coordinating Council |
| **RFC** | ReliabilityFirst Corporation |
| **SERC** | SERC Reliability Corporation |
| **SPP RE** | Southwest Power Pool Regional Entity |
| **TRE** | Texas Reliability Entity |
| **WECC** | Western Electric Coordinating Council |

| Region | Name | Title |
|---|---|---|
| FRCC | Vince Ordax | Manager of Planning |
| MRO | Daniel Jesberg | Engineer |
| MRO | John Seidel | Senior Manager, Event Analysis and Reliability Improvement |
| NPCC | Philip A. Fedora | Assistant Vice President, Reliability Services |
| NPCC | John G Mosier Jr. | Assistant Vice President of System Operations |
| RFC | Paul D Kure | Senior Consultant, Resources |
| RFC | Tim Fryfogle | Associate Engineer |
| SERC | Matthew J Turpen | Reliability Assessment Analyst |
| SERC | Barbara A. Doland | Data Analyst |
| SPP RE | Alan C Wahlstrom | Lead Engineer, Compliance |
| SPP RE | Debbie K Currie | Lead Engineer |
| TRE | Curtis Crews | Lead Reliability Assessment Engineer |
| WECC | Layne Brown | Manager, Reliability Assessments |

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# Media Release

## Summer Reserve Margins Predicted to be Adequate in Most Regions; ERCOT Below Reserve Capacity Targets

May 30, 2012

**ATLANTA** – Most of North America has sufficient resources available to meet summer peak demands, the North American Electric Reliability Corporation's (NERC) *2012 Summer Reliability Assessment* finds. However, planning reserve margins in the Electric Reliability Council of Texas (ERCOT) assessment area are projected to be below the NERC Reference Margin Level, the threshold by which resource adequacy is measured. In California, reserves are projected to be tight, but manageable, through the summer months.

"Reduced planning reserves in certain areas will challenge operations this summer," said Mark Lauby, vice president and director of Reliability Assessment and Performance Analysis. "NERC has reviewed the operating procedures and preparations in the assessment areas, and in most areas they appear to be sufficient to meet these challenges."

Since summer 2011, capacity resources have grown across North America by approximately 12,310 megawatts, most notably within the SERC Reliability Corporation and the Northeast Power Coordinating Council areas. Compared to the 2011 projections, NERC-wide total peak demand forecast is 3,700 MW lower. The largest increase in peak demand is expected in ERCOT, where a 1.7 percent increase is projected.

"With continued growth in peak demand and only a small amount of new generation coming online, resource adequacy levels in ERCOT have fallen below targets," said John Moura, manager of Reliability Assessment at NERC. "If ERCOT experiences stressed system conditions or record-breaking electricity demand due to extreme and prolonged high temperatures, system operators will most likely rely on demand response and emergency operating procedures, which may include initiating rotating outages to maintain the reliability of the interconnection."

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Key highlights for summer 2012:

- Extreme weather could lead to stress conditions in Southern California and Texas; planned interruptions of firm load may be necessary
- The unanticipated outage of San Onofre Nuclear Generating Station reduces available summer capacity; transmission ties critical to the reliability of Southern California
- Enhanced operations and planning approaches instituted in response to 2011 Southwest outage
- Variable generation continues to increase in most assessment areas
- Demand-side management key to maintaining reliability this summer
- Extreme weather events will challenge bulk power system operators
- Lower global liquefied natural gas supply may impact generation in New England; ISO to implement proactive measures

Download the *2012 Summer Reliability Assessment* by clicking here.

###

*The North American Electric Reliability Corporation's mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission in the United States to establish and enforce reliability standards for the bulk-power system. NERC has equivalent relationships with provincial and federal authorities in Canada. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast, and summer and winter forecasts; monitors the bulk power system; and educates, trains and certifies industry personnel. Learn more at www.nerc.com*

**From:** Kimberly Mielcarek
**To:** Kimberly Mielcarek
**Subject:** NERC Announcement - FERC-NERC Report on Northeast Transmission Outage Stresses Vegetation Management
**Date:** Thursday, May 31, 2012 12:22:31 PM

# Announcement

## FERC-NERC Report on Northeast Transmission Outage Stresses Vegetation Management

**Click for announcement, October 29-30, 2011 Inquiry Report**

Damaged electric distribution lines were the major cause of the widespread Northeastern customer outages during the October 2011 snowstorm, but utilities can apply lessons learned from the storm to improve performance and enhance reliability of their transmission lines in advance of the next storm, staff of the Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) said.

FERC and NERC staff issued a joint report issued a joint report on the transmission outages today. The joint inquiry focused on determining the causes of the transmission facility outages and on the steps utilities could take to improve their performance in maintaining grid reliability during the next large snowstorm or similar weather event. The purpose of the inquiry was not to investigate whether particular companies violated FERC-approved reliability standards or other applicable statutes and regulations.

The report finds 74 transmission lines and 44 transmission substations experienced outages. These problems along the transmission system caused less than 5 percent of customer outages at the peak of the October 29-30 storm, which left more than 3.2 million homes and businesses without power. Most of these transmission-caused customer outages lasted fewer than two days and none lasted more than five days.

For more information or assistance, please contact Kimberly Mielcarek.

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**Federal Energy Regulatory Commission**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# News Release

May 31, 2012
**Contacts:** Craig Cano, FERC (202) 502-8680
Kimberly Mielcarek, NERC (202) 644-8058

**FERC-NERC Staff Report on Northeast Transmission Outage Stresses Vegetation Management**

Damaged electric distribution lines were the major cause of the widespread Northeastern customer outages during the October 2011 snowstorm, but utilities can apply lessons learned from the storm to improve performance and enhance reliability of their transmission lines in advance of the next storm, staff of the Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) said today.

Staff of both FERC and NERC – FERC is the federal agency that oversees reliability of the transmission grid and NERC is the national electric reliability organization certified by FERC – issued a joint report on the transmission outages today. The joint inquiry focused on determining the causes of the transmission facility outages and on the steps utilities could take to improve their performance in maintaining grid reliability during the next large snowstorm or similar weather event. The purpose of the inquiry was not to investigate whether particular companies violated FERC-approved reliability standards or other applicable statutes and regulations.

Today's report finds 74 transmission lines and 44 transmission substations experienced outages. These problems along the transmission system caused less than 5 percent of customer outages at the peak of the October 29-30 storm, which left more than 3.2 million homes and businesses without power. Most of these transmission-caused customer outages lasted fewer than two days and none lasted more than five days.

Nearly three-quarters of the transmission line outages occurred when healthy trees, most located outside of utility rights-of-way, fell onto the lines uprooted by the weight of the snow compounded by the soft, wet ground. The report offers several recommendations to help reduce the adverse impacts of future weather events on the transmission system, including:

- Where appropriate, take targeted steps to address off-right-of-way danger trees;
- Employ best practices in managing vegetation on full rights-of-way;
- Lay the foundation for effective vegetation management when establishing new rights-of-way;
- Enhance storm preparedness and response plans as needed.

The joint report also recommends increasing the reporting of vegetation-caused outages and improving the content of required disturbance reports.

JR12-2

(30)

REPORT ON

# Transmission Facility Outages During the Northeast Snowstorm of October 29–30, 2011

## Causes and Recommendations



Prepared by the Staffs of the

Federal Energy Regulatory Commission *and the* North American Electric Reliability Corporation

# *Report on Transmission Facility Outages during the Northeast Snowstorm of October 29–30, 2011*

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# I. Introduction

On October 29-30, 2011, an unprecedented fall snowstorm hit the Northeastern United States, blanketing the region with up to two and a half feet of heavy, wet snow. Snowfall amounts broke all previous October records throughout the Mid-Atlantic and New England regions. The snowfall totals were most significant in New England, but parts of New York, New Jersey, and Pennsylvania also received well over a foot of snow. On the morning of October 30, near the end of the storm, more than 3.2 million homes and businesses were without power.[1] Thousands were without power for more than a week, some for as long as eleven days. Estimates put storm costs between approximately $1 billion and $3 billion.

Although the vast majority of these customer outages were caused by damage to electric distribution lines,[2] seventy-four transmission lines[3] and forty-four transmission substations[4] also experienced outages of ten minutes or more. Twenty-four of the transmission facilities (twenty-three lines and one substation) that experienced outages are Bulk-Power System (BPS) elements.[5]

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[1] Over the course of the weekend, more than 4.3 million customers lost power at one point or another. U.S. DEPARTMENT OF ENERGY, ENERGY ASSURANCE DAILY 1 (Oct. 31, 2011), http://www.oe.netl.doe.gov/docs/eads/ead103111b.pdf (showing the non-concurrent, peak reported outages of twenty-two utilities).

[2] Distribution lines, which carry power from the interstate transmission system to retail customers, are typically operated under 100 kilovolts (kV) and are generally regulated by the states.

[3] Transmission lines, which carry power from electric generating facilities to substations connected to the distribution system, are typically operated over 100 kV and generally – but not universally – regulated by the Federal Energy Regulatory Commission (FERC or the Commission) as to rates and terms of transmission service. See Federal Power Act § 201(b)(1), 16 U.S.C. § 824(b)(1). As explained in footnote 5, the Commission also has jurisdiction, pursuant to Section 215 of the Federal Power Act, over the reliability of the bulk-power system. Although some facilities operated under 100 kV are considered to be "transmission facilities" in certain contexts, this report uses that term to refer only to facilities operated at or above 100 kV.

[4] A transmission substation is connected to one or more transmission lines and houses transformers used to step up or step down (increase or decrease) electric energy voltages. Substations also contain, among other equipment, breakers that allow lines to be connected or isolated in order to clear faults or perform maintenance. Transmission substations impacted by the storm are discussed further in Section IV.B.

[5] Section 215(a)(1) of the Federal Power Act defines the bulk-power System as "(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy." 16 U.S.C. § 8240(a)(1). With respect to electric reliability, the Commission has jurisdiction over all users, owners, and operators of the BPS. FERC approves mandatory and enforceable Reliability Standards that are developed by the Electric Reliability Organization (ERO), the North American Electric Reliability Corporation (NERC), that apply to those BPS users, owners and operators registered by NERC. The Commission has adopted, at least for an initial period, NERC's definition of the term Bulk

In light of, among other things, the scope and seriousness of the October snowstorm event, the number of customers and states impacted, the duration of some of the outages, the storm's impact on entities subject to the Commission's jurisdiction, and the level of interest of the public and elected officials in the event, the Commission initiated an inquiry in November 2011 focused on the transmission- and BPS-related impacts of the storm. NERC also began an inquiry into the storm's effect on the BPS, and FERC and NERC combined their efforts into one joint inquiry. NPCC, which had been assisting NERC in its assessment of the storm event, also joined the inquiry team.

From the outset, this joint inquiry focused on determining the causes of the transmission facility outages and on the steps utilities could take to improve their performance in maintaining grid reliability during the next large snowstorm or similar weather event. The purpose of the inquiry has not been to investigate whether particular companies violated the Reliability Standards or other applicable statutes and regulations. NPCC, NERC, and FERC will follow their regular processes in identifying and pursuing any potential Reliability Standards violations. Nor has the purpose of this inquiry been to propose new or revised Reliability Standards or other regulations.

During the course of the inquiry, FERC, NERC, and NPCC staff obtained a significant amount of data from a variety of affected entities. Staff issued a first set of seven multi-part data requests to the thirty-six NERC-registered Transmission Owners and Transmission Operators[6] in the NPCC region, and sent a set of twenty-one multi-part data requests to those entities that reported experiencing transmission facility outages during the event. Staff conducted numerous follow-up calls and requested additional information from a number of entities. Staff also interviewed representatives of Northeast Utilities, the parent company of the three utilities that experienced the most

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Electric System (BES) for application of the Reliability Standards. The current definition of the BES is: "as defined by the [Regional Entity,] 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." *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 75, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007). The Northeast Power Coordinating Council (NPCC), the NERC-certified Regional Entity for the states affected by the October snowstorm, uses a performance-based test (rather than a voltage-based bright line) to determine which facilities in its region are subject to the Reliability Standards, and calls those facilities "Bulk Power System elements." *See* NPCC DOCUMENT A-10, CLASSIFICATION OF BULK POWER SYSTEM ELEMENTS (2007). Because the transmission facility outages caused by the October snowstorm occurred only in the NPCC region, this report uses NPCC's term "BPS elements."

[6] A Transmission Owner is an entity "that owns and maintains transmission facilities." A Transmission Operator is an entity that "is responsible for the reliability of its 'local' transmission system, and that operates or directs the operations of the transmission facilities." NERC, *Glossary of Terms Used in Electric Reliability Standards* (Feb. 8, 2012), http://www.nerc.com/files/Glossary_of_Terms.pdf.

transmission facility outages. Staff visited approximately twenty transmission sites on a three-day visit to Connecticut, Massachusetts, and New Hampshire. Staff reviewed relevant reports issued by the affected utilities and independent entities.

A number of agencies in several states affected by transmission and distribution facility outages during the October snowstorm are conducting their own inquiries into utility performance before, during, and after the event. Staff consulted with many of these state agencies, monitored their public proceedings, and discussed with them the report's preliminary findings and recommendations. Staff held outreach meetings with the Edison Electric Institute, the American Public Power Association, the National Rural Electric Cooperative Association, and the North American Transmission Forum, and also shared with them, on a non-public basis, the report's preliminary findings and recommendations. Feedback provided by state agencies and industry associations was considered in preparing this report.

This report: (1) presents staff's assessment of the October snowstorm event, including its impacts on transmission facilities and the BPS, and the causes of transmission facility outages; (2) discusses the applicability of the transmission vegetation management reliability standard to the event; and (3) provides a number of recommendations to industry that, if implemented, could improve utilities' performance and enhance transmission grid reliability during the next large snowstorm or similar event.

# II. Executive Summary

The early autumn snowstorm that hit the Northeast on October 29-30, 2011, was unprecedented in the amount of snowfall it produced and particularly devastating because of the untimely combination of several factors. As much as two and a half feet of heavy, wet snow fell at a time when many trees still had their leaves, following a warm, rainy period that left the ground unfrozen, saturated, and soft. The quantity of snow held by the unusually top-heavy trees, coupled with the soft, wet ground, resulted in a great number of healthy trees, most outside of utility rights-of-way,[7] being uprooted and falling onto distribution and transmission lines.

The storm left a trail of destruction that primarily affected distribution systems. Distribution lines were damaged in an estimated 50,000 locations ("trouble spots") throughout the Northeast.[8] Millions of customers[9] served by more than two dozen utilities lost power. Tens of thousands of customers served by Connecticut Light & Power Company (CL&P) were without electricity for more than a week, and some customers served by CL&P were without service for eleven days.[10]

Most of the damage, and customer outages, was due to impacts to the distribution system, which is generally subject to state or local regulation. The transmission system, which is subject to the Commission's jurisdiction, was impacted as well, but it caused less than 5% of customer outages at the storm's peak. Seventy-four transmission lines and forty-four transmission substations experienced sustained outages.[11] Transmission line outages were responsible for approximately 130,000 customer outages around the storm's peak. Most of these outages lasted for less than two days, and none lasted for more than five days. Nearly three-quarters of all of the transmission outages were

[7] Utilities rarely own the land on which they site transmission lines. Instead, utilities obtain rights, usually in the form of an easement, over portions of property owned by others. The easement allows the utility to construct, maintain, and operate transmission facilities and vegetation over a defined area of land, the "right-of-way."

[8] A "trouble spot" is a location where there is damage to a line requiring crew response to make conditions safe for the public, repair damage, and restore power.

[9] In the utility industry, the term "customer" generally refers to a single meter, whether at a residence, a retail store, or a factory; it does not refer to each person served at that meter.

[10] *See* WITT ASSOCIATES, CONNECTICUT OCTOBER 2011 SNOWSTORM POWER RESTORATION REPORT 11 (Dec. 1, 2011), *available at* http://www.wittassociates.com/assets/860/CTPowerRestorationReport20111201_FINAL_1_.pdf.

[11] For purposes of this report, facility outages lasting ten or more minutes are considered "sustained" outages.

caused when trees weighed down with heavy, wet snow fell onto transmission lines. Although most of the damage and outages were on the distribution system, this report addresses impacts on, and recommendations for, the FERC-jurisdictional transmission system.

Partly as a result of the August 14, 2003 blackout across the Northeast and Canada, which was caused in part by trees growing too close to transmission lines,[12] Congress passed legislation requiring the Commission to enact mandatory and enforceable Reliability Standards. One of those standards, FAC-003-1 (Transmission Vegetation Management Program), requires Transmission Owners to develop transmission vegetation management programs. These programs must include a schedule for vegetation inspections and specific vegetation clearance distances around transmission lines, have annual vegetation management work plans, and report certain vegetation-related outages.

This Standard's applicability to this event is limited in that FAC-003-1 only applies to transmission lines operated at voltages of 200 kV and above, plus any lower voltage lines identified by the applicable Regional Entity as critical to the reliability of the electric system in the region — and NPCC has not designated any lower-voltage facilities as critical for the purpose of applying FAC-003-1. In fact, FAC-003-1 applied to only one transmission facility forced out of service due to vegetation contact — a 345 kV transmission line in Connecticut — and that line outage did not cause any loss of service to customers. To the extent that a state does not have vegetation management standards governing transmission lines operated over 100 kV and the relevant Regional Entity has not designated lines operated under 200 kV as critical to the region's reliability for the purpose of applying FAC-003-1, lines operated between 100 kV and 200 kV in that state would not be covered by any federal or state vegetation management standard.

In addition, the Standard's applicability to the October event is limited because it does not specifically address off-right-of-way vegetation management. Further, although FAC-003-1 requires each Transmission Owner to "prepare and keep current, a formal transmission vegetation management program" that must include the Transmission Owner's objectives, practices, approved procedures, and work specifications,"[13] beyond this, each Transmission Owner has flexibility on the specific content of its vegetation

[12] 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 139 (Apr. 2004), *available at* http://www.nerc.com/filez/blackout.html.

[13] Reliability Standard FAC-003-1, at Requirement R-1.

management program, including specific direction on how to address danger trees[14] outside of Clearance 1[15] but within the right-of-way.

This report makes several recommendations to help reduce the adverse impacts of future, similar weather events on the transmission system, including: (1) where appropriate, taking targeted steps to address off-right-of-way danger trees; (2) employing best practices in managing vegetation on full rights-of-way; (3) laying the foundation for effective vegetation management when establishing new rights-of-way; and (4) enhancing storm preparedness and response plans as needed. In addition, staff recommends increasing reporting of vegetation-caused outages and improving the content of required disturbance reports.

[14] A danger tree is any tree that, if it fell, could contact a transmission line. *See*, *e.g.*, Accredited Standards Comm. (ASC) A300, Tree Care Indus. Ass'n, American National Standard for Tree Care Operations — Tree, Shrub, and Other Woody Plant Maintenance — Standard Practices (Integrated Vegetation Management a. Electric Utility Rights-of-Way) 72.5 (2006) [hereinafter ANSI A300].

[15] Clearances are defined and discussed in more detail in Section VII.A.

# III. The October 29–30, 2011 Nor'easter

An unprecedented early fall snowstorm blanketed the upper East Coast with up to two-and-a-half feet of snow in about a twenty-four hour period spanning October 29–30, 2011. Significant October snowstorms are rare, and the 2011 storm broke records throughout the Northeast. While the storm and its impacts on trees and power lines were not unanticipated, the severity of the storm exceeded forecasts, and its repercussions were wide-ranging and severe.

## A. Forecasts and Utility Preparations

By early in the afternoon of Thursday, October 27, 2011, weather agencies had issued forecasts that an unusual October Nor'easter would hit the New England and the Mid-Atlantic states on Saturday, October 29.[16] Several inches of snow were predicted to fall across the Northeast, and that day's forecasts warned that the coming storm would bring down trees and power lines across the region.[17] Predictions of maximum total snowfall amounts increased rapidly from October 27 to October 29. By the morning of October 29, forecasters were predicting up to fifteen inches of snow in some areas.[18] The snow was expected to begin falling in the late afternoon or early evening of October 29.[19]

A number of utilities began preparations for the storm on Friday, October 28. In the lead-up to the storm, they held internal planning meetings, increased staff in

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[16] *See*, *e.g.*, CL&P Resp. to Data Req. PURA-02, Q-EL-014, Conn. Pub. Utils. Regulatory Auth. Docket No. 11-09-09, Nov. 23, 2011 (providing the Telvent weather report from 1:00 p.m. on October 27, 2011, which mentioned a storm arriving on October 29, 2011). A Nor'easter is a severe winter weather event that produces heavy snow or rain, severe winds, and significant waves. A Nor'easter gets its name from the strong northeasterly winds blowing in from the ocean ahead of the storm and over coastal areas. Nat'l Oceanic & Atmospheric Admin., *National Weather Service Glossary*, http://www.weather.gov/glossary/.

[17] *See*, *e.g.*, CL&P Resp. to Data Req. AG-03, Q-AG-117-SP01, Conn. Pub. Utils. Regulatory Auth. Docket No. 11-09-09, Nov. 18, 2011 (providing National Weather Service briefing slides used by CL&P to prepare for the storm).

[18] *See*, *e.g.*, CL&P Resp. to Data Req. PURA-02, Q-EL-014, Conn. Pub. Utils. Regulatory Auth. Docket No. 11-09-09, Nov. 23, 2011 (providing the Telvent weather report from 6:00 a.m. on October 29, 2011, which predicted up to fifteen inches of snow in western Massachusetts).

[19] Nat'l Oceanic & Atmospheric Admin., *Rare October Winter Storm in the Northeast* (Oct. 28, 2011), http://www.nnvl.noaa.gov/MediaDetail2.php?MediaID=874&MediaTypeID=1.

operations centers, and placed in-house and contract field crews on call.[20] Regional mutual aid groups, through which utilities can request line restoration assistance from other utilities, also held conference calls. However, due in part to the moderate snowfall amounts in weather predictions from that morning, few utilities requested assistance on October 28.[21] Nor did many utilities make mutual assistance requests on the morning of Saturday, October 29; at that point, there was a general understanding that utilities would be holding their crews in order to respond to the event in their own service territories.[22] However, snowfall amounts exceeded forecasts, and by Saturday afternoon, utilities began to see that more manpower would be required to address the rapidly increasing outages. Many utilities then began requesting aid from the mutual assistance groups.[23] But because the storm was so widespread — and demand was so great — there were few regional crews immediately available.[24] In addition, there generally was only limited pre-staging of crews (i.e., positioning field workers at locations around a utility's service territory before a weather event so that they will be on the scene to make repairs as soon as the storm is over).

Some utilities — in particular, CL&P — have faced criticism at the state level for inadequate storm preparation, including failing to request mutual assistance earlier or to pre-stage field crews in order to speed response times.[25] Utility emergency preparation and response is almost entirely outside of the Commission's jurisdiction.[26] However, as discussed below, staff's review of the impact of utility preparation and response on transmission restoration found no indication that inadequate preparation materially

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[20] *See*, *e.g.*, Davies Consulting, Final Report: Connecticut Light and Power's Emergency Preparedness and Response to Storm Irene and the October Nor'easter 19 (Feb. 27, 2012), *available at* http://media2.wtnh.com/docs/Storm-Review-Final-Report.pdf

[21] *See*, *e.g.*, Witt Associates, *supra* note 10; Central Hudson gas & Electric Corp., 16 NYCRR — Part105 Compliance Filing: Report and Evaluation of October 2011 Snowstorm, October 29–November 4, 2011, at 22-23 (Jan. 5, 2012), *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={23000E96-EBCF-45C1-BB29-387EF9943C33}; Davies Consulting, *supra* note 20, at 19.

[22] *See*, *e.g.*, CENTRAL HUDSON GAS & ELECTRIC CORP., *supra* note 21, at 5; WITT ASSOCIATES, *supra* note10, at 21.

[23] *See*, *e.g.*, CENTRAL HUDSON GAS & ELECTRIC CORP., *supra* note 21, at 5; WITT ASSOCIATES, *supra* note 10, at 21.

[24] *See*, *e.g.*, CENTRAL HUDSON GAS & ELECTRIC CORP., *supra* note 21, at 5; WITT ASSOCIATES, *supra* note 10, at 21.

[25] *See, e.g.*, JOE MCGEE ET AL., REPORT OF THE TWO STORM PANEL, PRESENTED TO: GOVERNOR DANNEL P. MALLOY 10–11 (Jan. 9, 2012), *available at* http://www.governor.ct.gov/malloy/lib/malloy/two_storm_panel_final_report.pdf; WITT ASSOCIATES, *supra* note 10, at 2-3.

[26] Although several Emergency Operations Reliability Standards deal with registered entities' responses to emergency situations, those Standards are focused on BPS operation issues, and not more conventional preparation and response issues like employee training, staffing levels, or field crew response.

hindered restoration of transmission facilities, as opposed to the more serious preparation and restoration problems reported on the distribution side.

## B. Storm Produces Record Amounts of October Snowfall

Not long after the storm began, it became clear that snowfall totals would exceed projections. Wet snow began falling in the late morning of October 29.[27] Snowfall was heavy by mid-day, and it fell quickly: up to three inches per hour for sustained periods.[28] Within about twenty-four hours, some areas had received two-and-a-half feet of snow. The highest amounts of total snowfall were in Massachusetts, where Peru recorded 32 inches, and in New Hampshire, where Jaffrey recorded 31.4 inches.[29] The storm set records for October snowfall across the region. On October 29 alone, Hartford, Connecticut, received 12.3 inches of snow, far surpassing the previous October record of 1.7 inches.[30] That same day, Concord, New Hampshire, received a record 13.6 inches of snow, and Worcester, Massachusetts, received a record 11.4 inches.[31] The previous records were 3.0 inches and 7.5 inches, respectively.[32]

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[27] Nat'l Weather Serv., *October 29th Historic Early Season Snowstorm*, http://www.erh.noaa.gov/okx/StormEvents/10292011/index.html; DAVIES CONSULTING, *supra* note 20, at 18.

[28] Nat'l Weather Serv. Forecast Office, Boston, Mass., *Review of Snow-tober 2011*, http://www.erh.noaa.gov/box/sigevents/Snowtober_2011/

[29] Nat'l Weather Serv., *Significant Weather Event: Oct. 29–30, 2011*, http://www.erh.noaa.gov/box/displayEvent.php?event=Oct_29-30_2011&element=snow.

[30] Nat'l Climatic Data Ctr., *CT Daily Snowfall Records Set in October 2011*, http://www.ncdc.noaa.gov/extremes/records/daily/snow/2011/10/00?sts[]=CT#records_look_up.

[31] Nat'l Climatic Data Ctr., *MA Daily Snowfall Records Set on October 29, 2011*, http://www.ncdc.noaa.gov/extremes/records/daily/snow/2011/10/29?sts[]=MA#records_look_up (providing daily snowfall records for cities in Massachusetts on October 29, 2011); Nat'l Climatic Data Ctr., *NH Daily Snowfall Records Set on October 29, 2011*, http://www.ncdc.noaa.gov/extremes/records/daily/snow/2011/10/29?sts[]=NH#records_look_up (providing daily snowfall records for cities in New Hampshire on October 29, 2011).

[32] Nat'l Weather Serv., *Concord Climate Data For the Year 2011* (Jan. 18, 2012), http://www.srh.noaa.gov/data/GYX/CLACON; Nat'l Climatic Data Serv.; *MA Monthly Snowfall Records Set in 2011*, http://ncdc.noaa.gov/extremes/records/monthly/snow/2011/10/00?sts[]=MA#records_look_up.

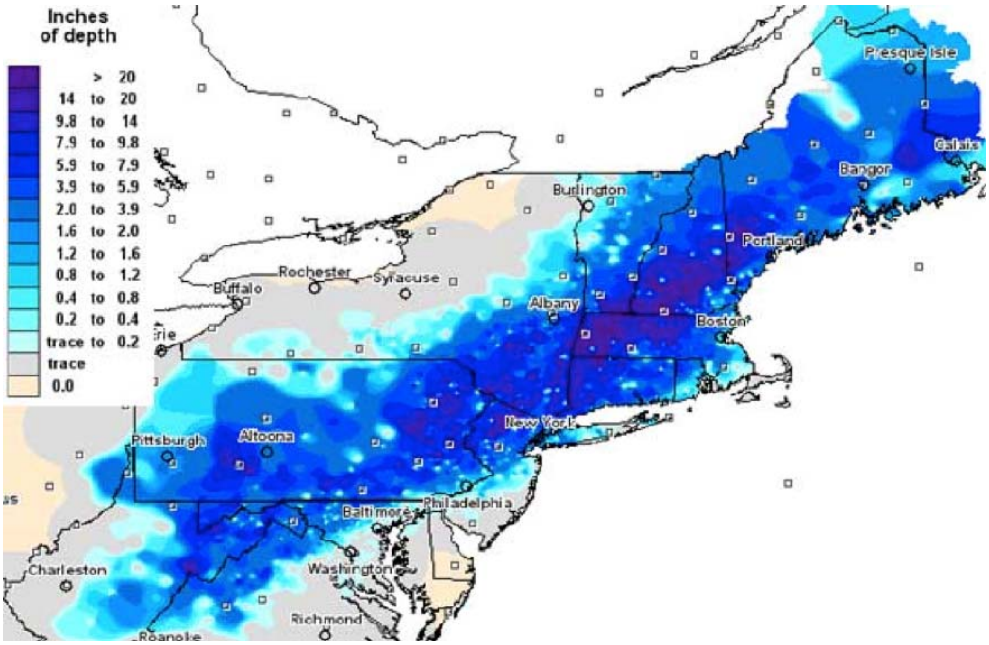



**Figure 1: Snowfall Totals Across the Northeast on October 30, 2011**

*Source: NOAA, nohrsc.noaa.gov/interactive*

The National Weather Service called the October Snowstorm a "rare and historic October Nor'easter"[33] and rated it as the strongest fall storm on record for the Northeast region.[34] Connecticut Governor Dan Malloy said that "a review of state records dating back to 1650 indicates that this storm is the most severe October Nor'easter in Connecticut history."[35] The only other notable October snowstorm in New England in the last one hundred and fifty years, which occurred on October 4, 1987, was far less destructive. That storm produced between six and twenty inches of snowfall from Albany, New York, to the Western Berkshires in Massachusetts, and caused only about 300,000 customer outages,[36] compared to the more than 3 million outages caused by the October 2011 storm.

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[33] Nat'l Weather Serv., *Winter Storm Summary for October 29, 2011 Event*, http://www.erh.noaa.gov/phi/show_wss.php.

[34] Email from NOAA staff to FERC staff (Mar. 15, 2012) (on file with OE staff). The October snowstorm is the only October storm to be ranked by NOAA among the 45 highest-impact snowstorms that have affected the Northeast urban corridor. Nat'l Climatic Data Ctr., *The Northeast Snowfall Impact Scale*, NOAA, http://www.ncdc.noaa.gov/snow-and-ice/rsi/nesis.

[35] Letter from Dannel P. Malloy, Conn. Governor, to Barack Obama, President (Nov. 11, 2011) [hereinafter Malloy Letter].

[36] Robert D. McFadden, *Early Snowstorm Covers Northeast*, N.Y. TIMES (Oct. 5, 1987), http://www.nytimes.com/1987/10/05/us/early-snowstorm-covers-northeast.html?pagewanted=all&src=pm.

## C. Leafy Trees and Prior Rainfall Compound the Impact of the Snowstorm

The effects of record amounts of heavy, wet snow were particularly severe because the snow fell across densely wooded areas where deciduous trees had not yet lost many of their leaves. Due to an unusually warm and wet September and October, leaf drop was significantly lower than normal for late October. For example, before the October storm, most of Massachusetts and Connecticut had only experienced "Moderate" — rather than the typically "High" — leaf drop.[37] The weight of snow on the leaves put significant strain on trees, causing limbs to snap and entire healthy trees to fall.

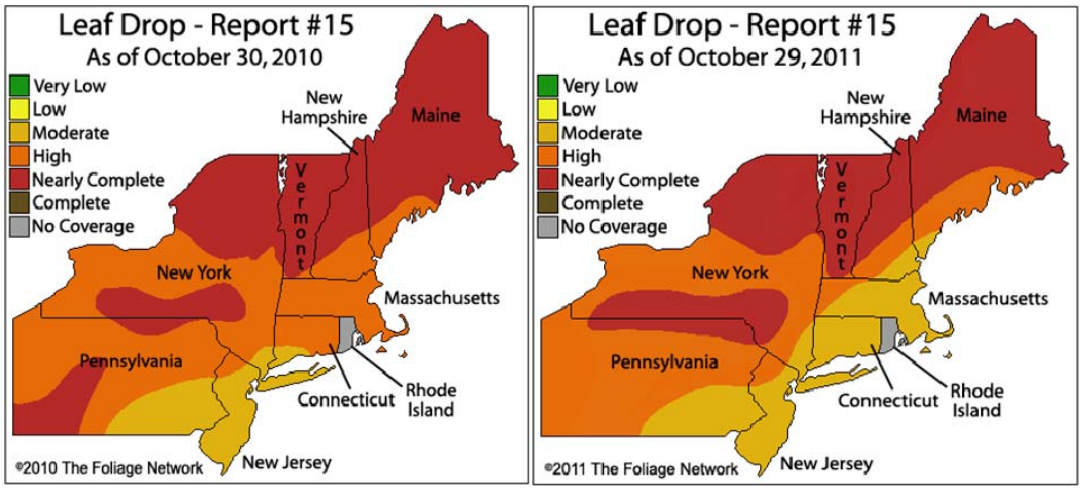



**Figure 2: Leaf Drop Reports, October 2010 vs. October 2011**
*Source: The Foliage Network*

Moreover, the ground throughout much of the Northeast was saturated due to an abnormally wet year — including significant August rainfall from Tropical Storm Irene. In fact, August 2011 was the wettest month on record in the Northeast since recording began in 1895.38 Because the saturated ground had not yet frozen, the weight of the

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[37] *See Report #15 – Oct. 29, 2011*, THE FOLIAGE NETWORK, http://www.foliagenetwork.net/index.php?option=com_content&view=article&id=333:ne-foliage-report-15-2011&catid=34:northeast-us&Itemid=68; *Report #15 – Oct. 30, 2011*, THE FOLIAGE NETWORK, http://www.foliagenetwork.net/index.php?option=com_content&view=article&id=275:ne-foliage-report-10302010&catid=62:northeast-us&Itemid=85.

[38] In August 2011 an average of 8.53 inches of precipitation was recorded in the Northeast, while the 20th century regional average is only 3.85 inches. Nat'l Climatic Data Ctr., *Precipitation Rankings August 2011 Northeast*, NOAA, http://www.ncdc.noaa.gov/temp-and-precip/ranks.php?parameter=pcp&state=101&div=0&periods[]=1&month=8&year=2011. The year 2011 was also the wettest year on record for the Northeast since 1895: an average of 56.04 inches of precipitation was recorded, while the 20th century average is only 41.08 inches. Nat'l Climatic Data Ctr., *Precipitation Rankings December 2011 Northeast*, NOAA, http://www.ncdc.noaa.gov/temp-and-precip/ranks.php?periods%5B%5D=12&parameter=pcp&year=2011&month=12&state=101&div=0.

heavy, wet snow on leafy trees caused many healthy trees across the region to uproot. On November 1, 2011, the Connecticut Department of Transportation estimated there were 24,000 trees downed on Connecticut roads alone. As explained by Governor Malloy: [39]

> *"The combination of heavy wet snow and near freezing air caused adherences of the snow to all objects including trees, which had not yet lost their seasonal foliage. The weight of the snow on trees and power lines, combined with very wet soils as a result of Tropical Storm Irene and the remnants of Tropical Storm Lee, quickly overwhelmed the ability of trees to remain upright under the added weight. This added weight de-limbed hundreds of thousands of trees and uprooted tens of thousands of additional trees in just 12 hours."*

The October snowstorm crippled much of the Northeast. As noted above, more than 3 million customers lost electric power. Activity in the affected states ground to a halt: many roads were impassable and scores of schools and businesses closed.[40] States of emergency were declared in many states, including Connecticut,[41] Massachusetts,[42] New Hampshire,[43] and parts of New York.[44] News reports identified at least twenty-two storm-related deaths.[45] The National Oceanic and Atmospheric Administration estimates the costs of the storm to be between $850 and $900 million, and one unofficial estimate puts the costs at more than $3 billion.[46]

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[39] *See* Malloy Letter, *supra* note 35.

[40] *See* Lauren Keiper, *Millions Without Power After US Northeast Snowstorm*, REUTERS (Oct. 31, 2011), http://www.reuters.com/article/2011/10/31/uk-weather-northeast-idUSLNE79U02Y20111031.

[41] Press Release, Gov. Malloy Declares State of Emergency (Oct. 29, 2011), *available at* http://www.governor.ct.gov/malloy/cwp/view.asp?A=4010&Q=.

[42] Press Release, Governor Lynch Requests FEMA's Reconsideration of Emergency Disaster Declaration (Nov. 2, 2011), *available at* http://www.governor.nh.gov/media/news/2011/110211-emergency.htm.

[43] Press Release, Governor Patrick Meets with Utility Company Officials on Storm and Power Recovery Efforts (Oct. 31, 2011), *available at* http://www.mass.gov/governor/pressoffice/pressreleases/2011/111031-storm-power-recovery.html.

[44] Press Release, Governor Cuomo Declares State of Emergency for Counties Hit Hard by Winter Storm (Oct. 29, 2011), *available at* http://www.governor.ny.gov/press/10292011stateofemergency.

[45] CNN Wire Staff, *Freak Snowstorm Blamed for at Least 22 Deaths*, CNN (Nov. 3, 2011), http://articles.cnn.com/2011-11-03/us/us_east-coast-storm_1_carbon-monoxide-poisoning-cl-p-power-outages?_s=PM:US.

[46] AON BENFIELD, OCTOBER 2011 MONTHLY CAT RECAP – IMPACT FORECASTING 2 (Nov. 3, 2011), *available at* http://thoughtleadership.aonbenfield.com/ThoughtLeadership/Documents/201111_if_monthly_cat_recap_october.pdf; Mary O'Leary, *Gov. Malloy: "What We Need is Action" on Connecticut Power Crisis*, NEW HAVEN REGISTER (Nov. 2, 2011), http://www.governor.ct.gov/malloy/cwp/view.asp?A=11&Q=489996 (quoting Governor Malloy as anticipating

# IV. Significant and Widespread Damage to Electric Delivery Infrastructure

The October storm's historic snowfall and resulting tree damage devastated the system of high and low voltage wires that distribute power across the Northeast, leaving approximately 3.2 million customers from Pennsylvania to Maine without power near the end of the storm. The vast majority of the damage to electric delivery infrastructure was to the distribution system. However, the storm's impact on transmission facilities was also significant. Seventy-four transmission lines in a half-dozen states experienced sustained outages.

## A. Distribution Facility Damage and Customer Impact

Exact measures of the total physical damage to distribution systems are hard to determine, but there were an estimated 50,000 separate locations across the Northeast where utility crews were required to remove trees from or physically repair distribution lines ("trouble spots"). This serious and widespread damage to distribution facilities caused more than 95% of customer outages. The map on the next page overlays a snapshot of several utilities' customer outages on a map showing snowfall totals across the Northeast.

storm costs would exceed $3 billion); Email from NOAA staff to FERC staff (Mar. 29, 2012) (estimating costs at between $850 million and $900 million) (on file with OE Staff).

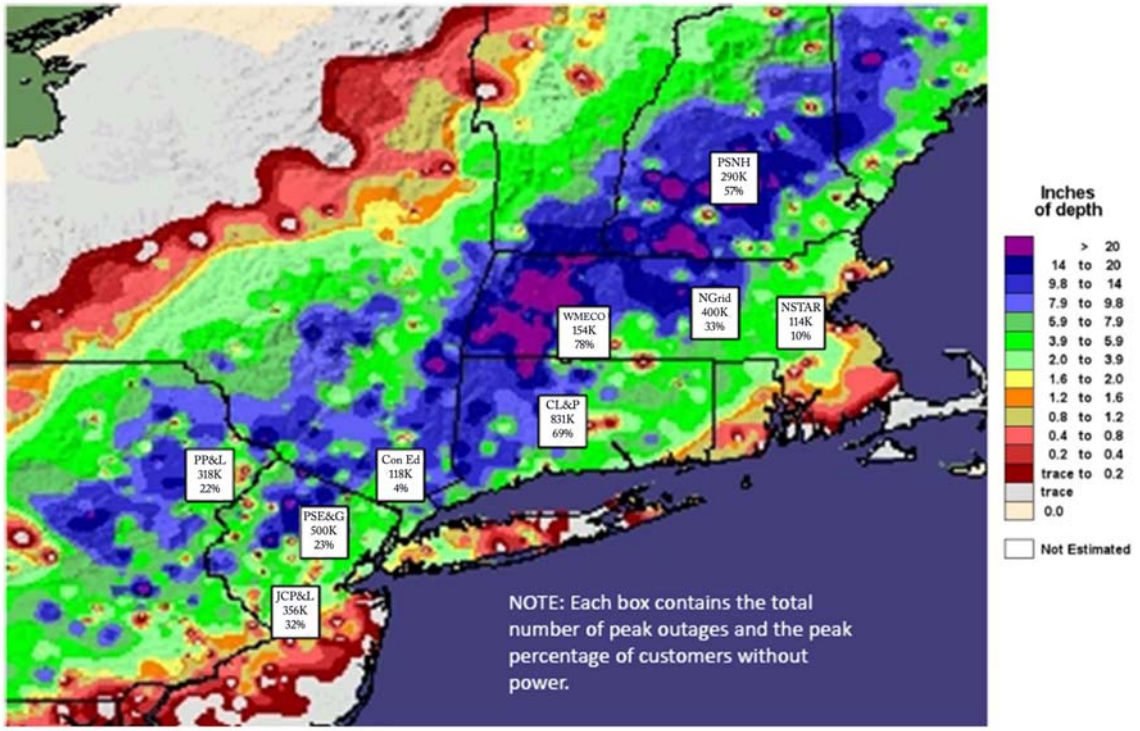



**Figure 3: Snowfall Amounts and Customers That Lost Power**

*Source: NOAA, National Operational Hydrologic Remote Sensing Center, Interactive Snow Information47 and U.S. Department of Energy, Energy Assurance Daily.*[48]

There was significantly more damage to distribution facilities than transmission facilities for a number of reasons, including the fact that in some areas there are approximately twenty times more miles of distribution lines than transmission lines.[49] In addition, under typical industry practices, vegetation is generally allowed to grow much closer to distribution lines than transmission lines because there is less risk of flashover[50] between low-voltage distribution lines and nearby trees.

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[47] *Available at* http://www.nohrsc.nws.gov/interactive/html/map.html?ql=station&zoom=&loc=Latitude%2CLongitude%3B+City%2CST%3B+or+Station+ID&var=snowfall_72_h&dy=2011&dm=10&dd=30&dh=0&incr=+%2B+&snap=1&o9=1&lbl=m&mode=pan&extents=us&min_x=-76.041666666669&min_y=33.741666666667&max_x=-63.450000000002&max_y=43.816666666667&coord_x=-69.745833333336&coord_y=38.779166666667&zbox_n=&zbox_s=&zbox_e=&zbox_w=&metric=0&bgvar=dem&shdvar=shading&palette=1&width=1000&height=800&nw=1000&nh=800&h_o=2&font=0&js=1&uc=0

[48] U.S. Department of Energy, supra note 1.

[49] See About NU, Northeast Utilities, http://www.nu.com/aboutnu/nufacts.asp (listing 4,500 circuit miles of transmission lines and 72,000 pole miles of distribution lines).

[50] Flashover is the spontaneous arcing of electricity from a line to a grounded object like a tree.

A number of state utility commissions and other state government agencies have initiated inquiries into the distribution-level customer outages caused by the storm.[51] In addition, several utilities (and some independent entities) have produced reports on the event that focus on distribution system impacts.[52]

## B. Transmission Facility Damage and Customer Impact

Although its impact was not as extensive as the damage to the distribution system, the October snowstorm impacted many transmission facilities. Near the end of the storm, about 130,000 customers across six states lost power as a result of transmission line outages.

### 1. Transmission Outages

Of the seventy-four transmission lines forced out of service for a sustained period during to the storm, the vast majority (seventy) were 115 kV facilities. One 138 kV and three 345 kV lines also experienced outages.

[51] The Connecticut Public Utilities Regulatory Authority (Docket No. 11-09-09), the Massachusetts Department of Public Utilities (Docket No. 11-119), the New Hampshire Public Utilities Commission, and the New York State Public Service Commission (Case No. 11-M-0595) are all conducting inquiries.

[52] *See*, *e.g.*, Central Hudson Gas & Electric Corp., *supra* note 21; Consolidated Edison Company of New York, Inc., Report on Preparation and System Restoration Performance: Nor'easter October 29 through November 3, 2011 (Jan. 5, 2012), *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={512EF4A0-EC4C-4204-A527-B047022B6FC3}; Davies Consulting, *supra* note 20; McGee, *supra* note 25; Public Service of New Hampshire, Amp Up and Power On: October Nor'easter 2011 (Nov. 2011), *available at* http://www.hollisnh.org/announce/2011OctoberNor'easterReport.pdf; Western Massachusetts Electric Company's Report to the Department of Public Utilities on Expectations for Electric Distribution Company Performance Regarding Emergency Events (Dec. 20, 2011), *available at* http://www.env.state.ma.us/dpu/docs/electric/11-119/12202011-tech-session.pdf.

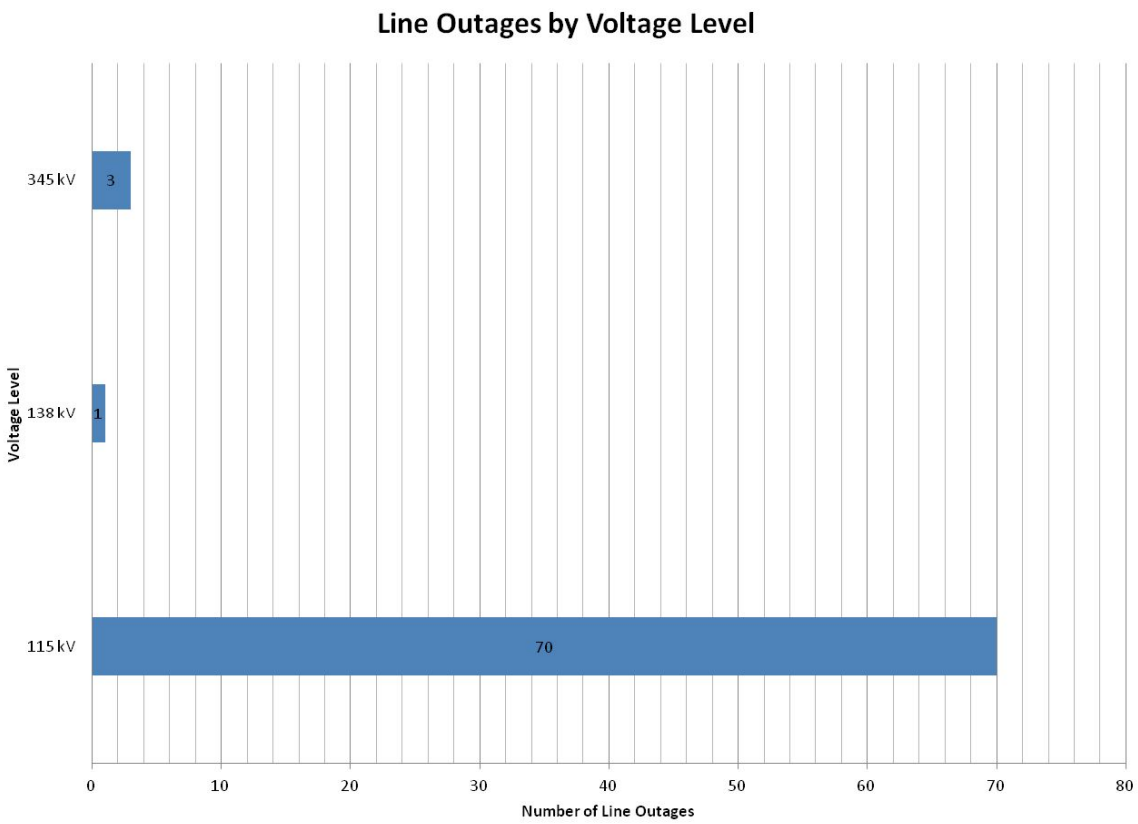



**Figure 4: Transmission Line Outages by Voltage Level**

There were also seven brief — between one and nine minute — line trips, four of which were caused by relay misoperations.[53]

Twenty-three of these seventy-four line outages occurred on NPCC-designated BPS elements. As explained in footnote 5, NPCC uses a performance-based test to designate facilities as BPS elements.[54]

[53] Relay misoperations occur when an automated line monitoring and communications device — a relay — transmits an incorrect signal to a line's breakers, causing the breakers to open when that action is not necessary. Failure of a relay to operate when it should is also considered a misoperation. The one relay misoperation that resulted in a transmission line outage of ten or more minutes is discussed in Section V.C.

[54] NERC has filed, for Commission consideration, a revised definition of BES that would impose a bright-line threshold of 100 kV, such that if approved, all facilities over 100 kV would be part of the Bulk Electric System and subject to most Reliability Standards unless a specific exception was granted or generic inclusion was made. *See N. Am. Elec. Reliability Corp.*, Petition, Docket No. RM 12-06-000 (filed Jan. 25, 2012). This report takes no position on the BES definition filing.

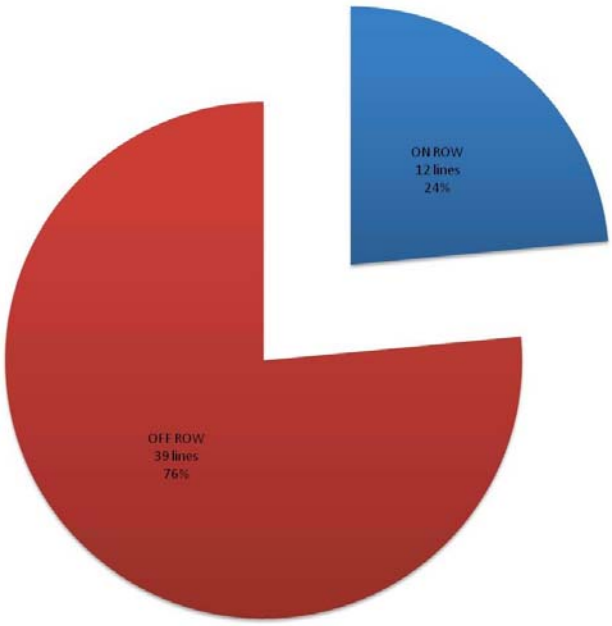



**Figure 5: Total Outages: BPS vs. Non-BPS Elements**

Because transmission lines conduct power from generating facilities to substations, transmission line outages can cause substation outages.[55] During the October snowstorm, transmission line outages forced forty-four transmission substations out of service, including one NPCC designated as a BPS element. Loss of power to transmission substations is significant for two main reasons. First, many transmission substations provide power to distribution systems, so that the loss of power to a transmission substation can result in thousands of customer outages. Second, transmission substations contain relays and breaker controls that operate to protect individual transmission lines and stabilize the power grid as a whole. When a substation's power source is lost, substation battery banks provide backup power to control equipment and breakers, but those batteries only last for a limited period of time, at which point the equipment can no longer perform its functions. These forty-four transmission substation outages, combined with seventy-four transmission line outages, constituted a significant transmission event.

[55] Sometimes only one transmission line feeds power to a substation. If that single source line experiences an outage, the entire substation will be out of service. Generally, multiple transmission lines provide power to a substation; in that case, the substation will go out of service because of transmission line outages only if all of the transmission lines serving that substation are out of service.

## 2. Affected States and Utilities

A half-dozen states — Connecticut, Maine, Massachusetts, New Hampshire, New York, and Rhode Island — and ten utilities experienced transmission outages on lines they own, or co-own and maintain. Half of those outages occurred in just one state, Connecticut.[56] The chart below shows the number of outages by state.

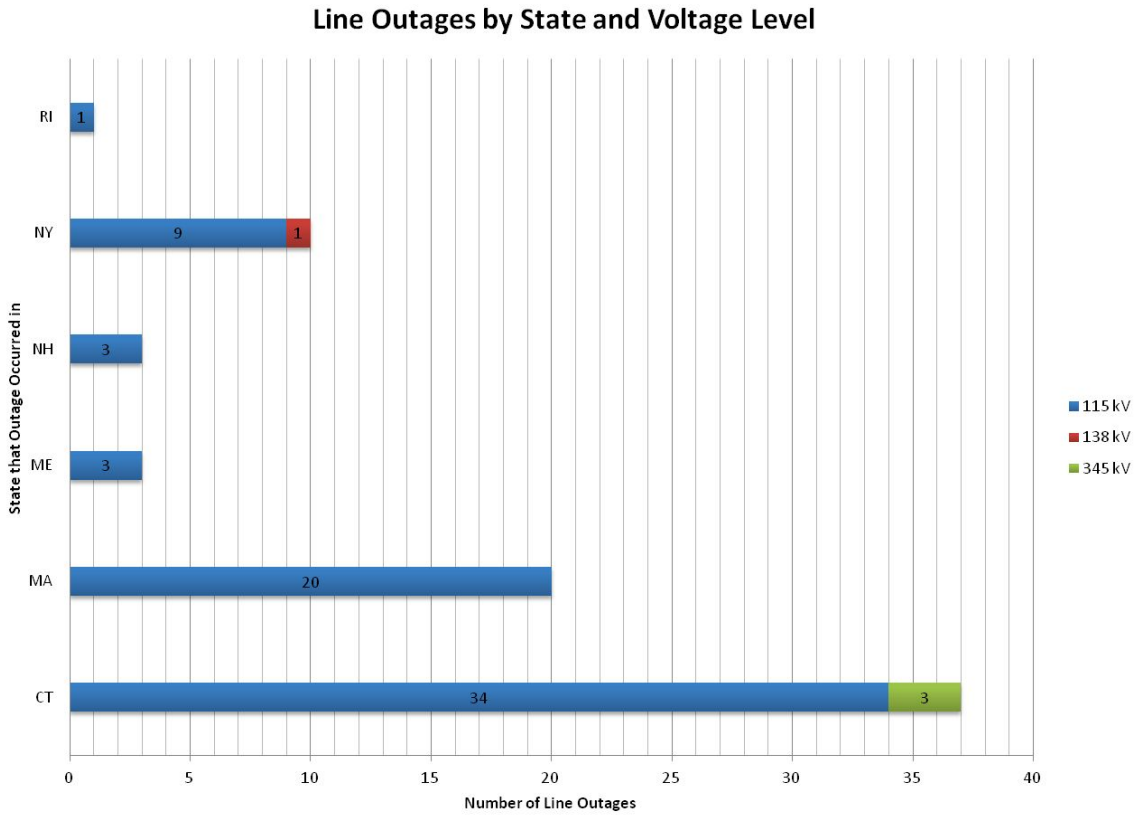



**Figure 6: Transmission Line Outages by State and Voltage Level**

As the following map shows, transmission line outages were concentrated in the Connecticut River Valley area, through Connecticut and into Massachusetts.

[56] Other states, such as Pennsylvania and New Jersey, experienced significant snowfall and distribution facility outages, but no transmission facility outages.

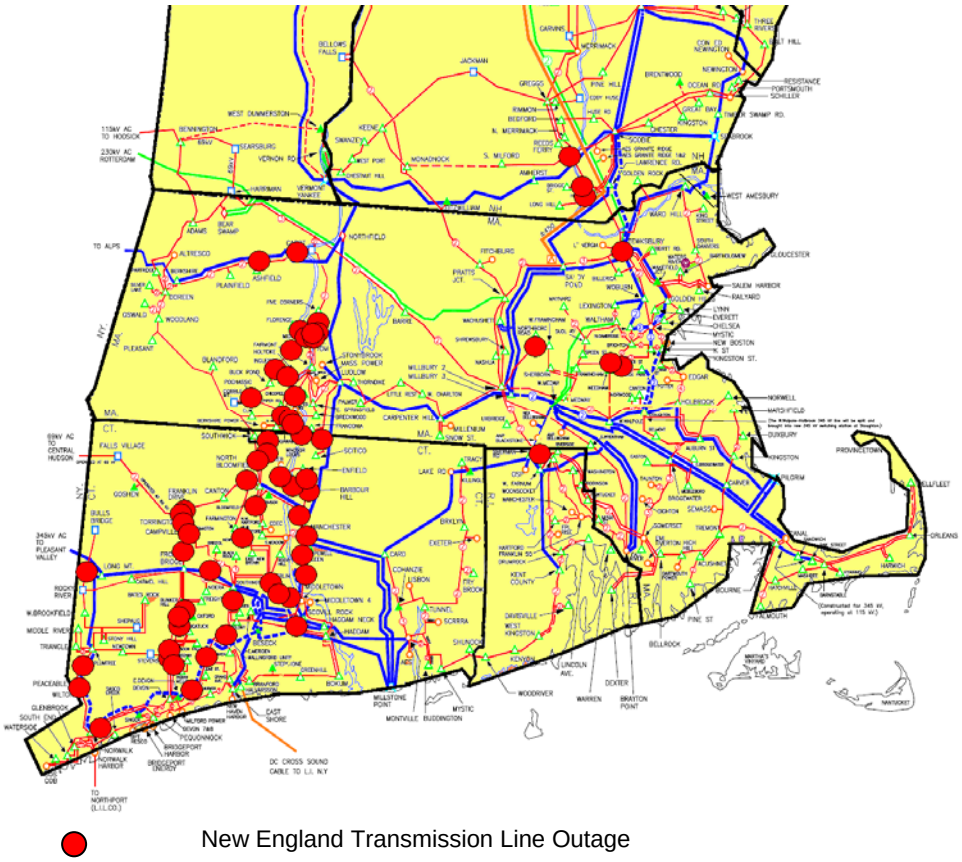



**Figure 7: ISO-NE Transmission Line Outages During the October Snowstorm**

*Source: ISO-New England*

The service territories of CL&P and Western Massachusetts Electric Company (WMECO), two subsidiaries of Northeast Utilities (NU), largely cover this area. As shown in the chart below, these two companies had the most transmission line outages. A third NU subsidiary, Public Service of New Hampshire (PSNH), had an additional three transmission line outages. Overall, outages of facilities owned — or co-owned, operated, and maintained — by NU subsidiaries[57] accounted for fifty-four of the October storm's seventy-four transmission line outages (approximately 74%).

[57] NU and NSTAR merged on April 10, 2012, and NSTAR is now a subsidiary of NU. Because the merger occurred after the October snowstorm, this report does not include NSTAR as an NU subsidiary.

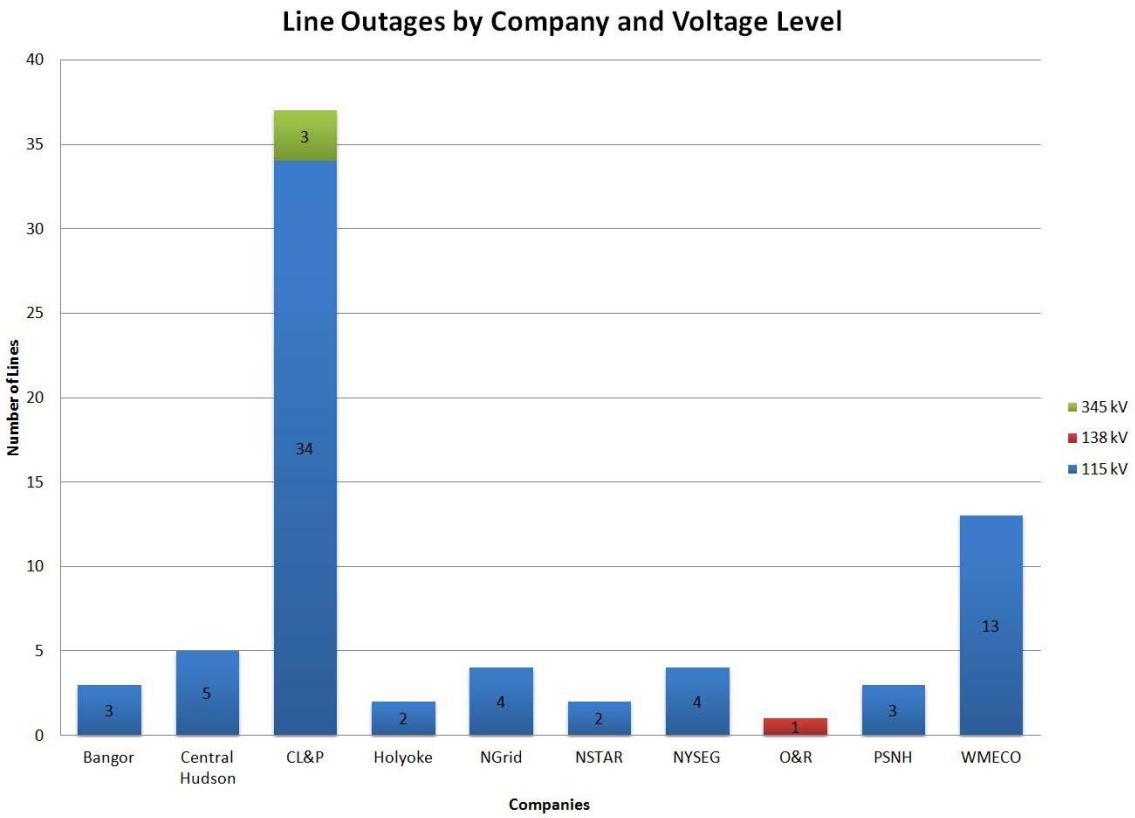



**Figure 8: Line Outages by Company and Voltage Level**[58]

## 3. Transmission Facility Outages Had Relatively Limited Impacts on Customers and Were Restored Quickly

Although seventy-four transmission line outages is a significant transmission event, these outages impacted far fewer customers than the distribution facility outages. At the storm's peak, damage to the transmission system caused approximately 130,000 homes and businesses to lose power, less than 5% of all of the storm-related customer outages. In addition, the peak number of transmission-caused customer outages (which rose above 100,000 customers for only about two hours) was relatively small compared to distribution-caused outages. While many customers impacted by distribution facility outages were without service for more than five days – and some for eleven – service was restored to all customers that lost power due to transmission outages in less than five

[58] The full names of the utility companies included in this chart are: Bangor Hydro Electric Co.; Central Hudson Gas & Electric Corp.; Connecticut Light & Power Co.; Holyoke Gas & Electric Department; National Grid USA; NSTAR Electric & Gas Co.; New York State Electric & Gas Co.; Orange & Rockland Utilities, Inc.; Public Service of New Hampshire; and Western Massachusetts Electric Co. Where a line is co-owned by more than one utility, this report attributes the outage to the company with the responsibility for maintaining the line where the outage occurred.

days. In fact, service was restored to the majority (77% percent) of such customers in less than forty-eight hours.

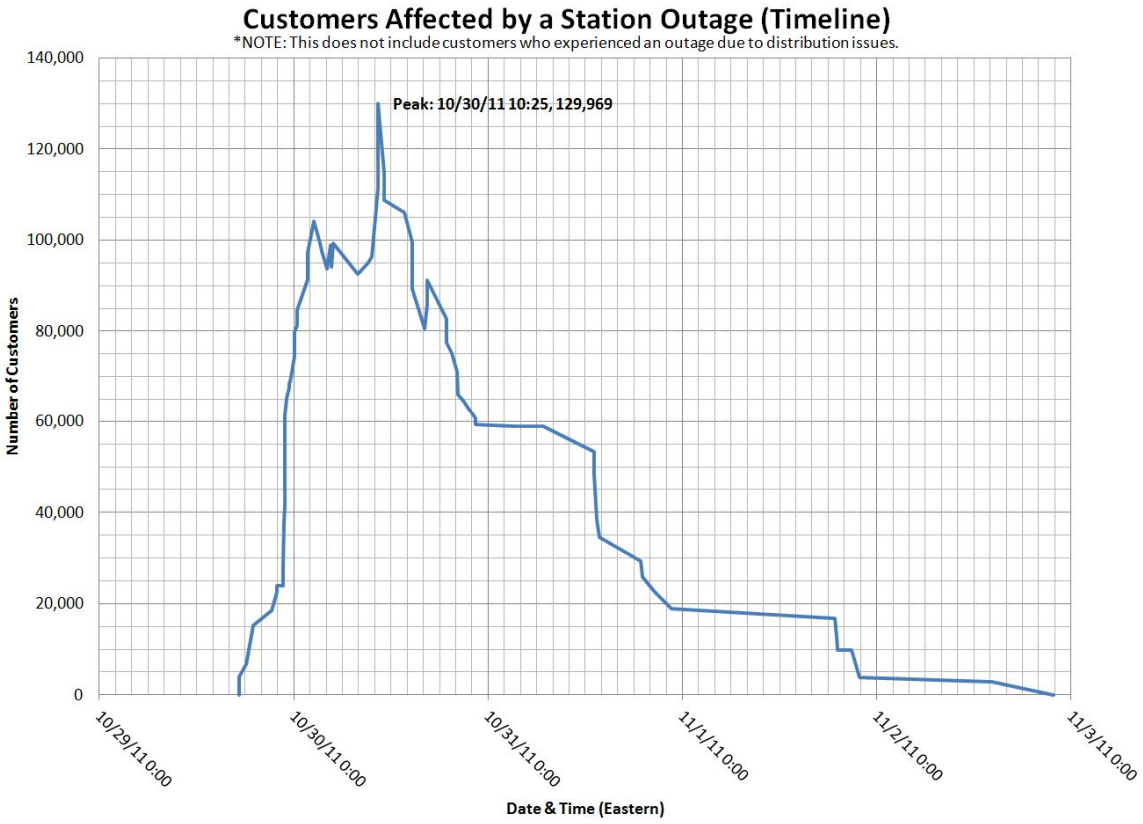



**Figure 9: Timeline of Customers Affected by a Transmission Station Outage**

While most transmission facilities were restored relatively quickly, four were out of service for nearly a week, and an additional three remained out of service between seven and eight days. However, none of these seven transmission line outages resulted in customer outages or were, at that time, necessary for BPS stability. The following chart illustrates the duration of transmission line outages.

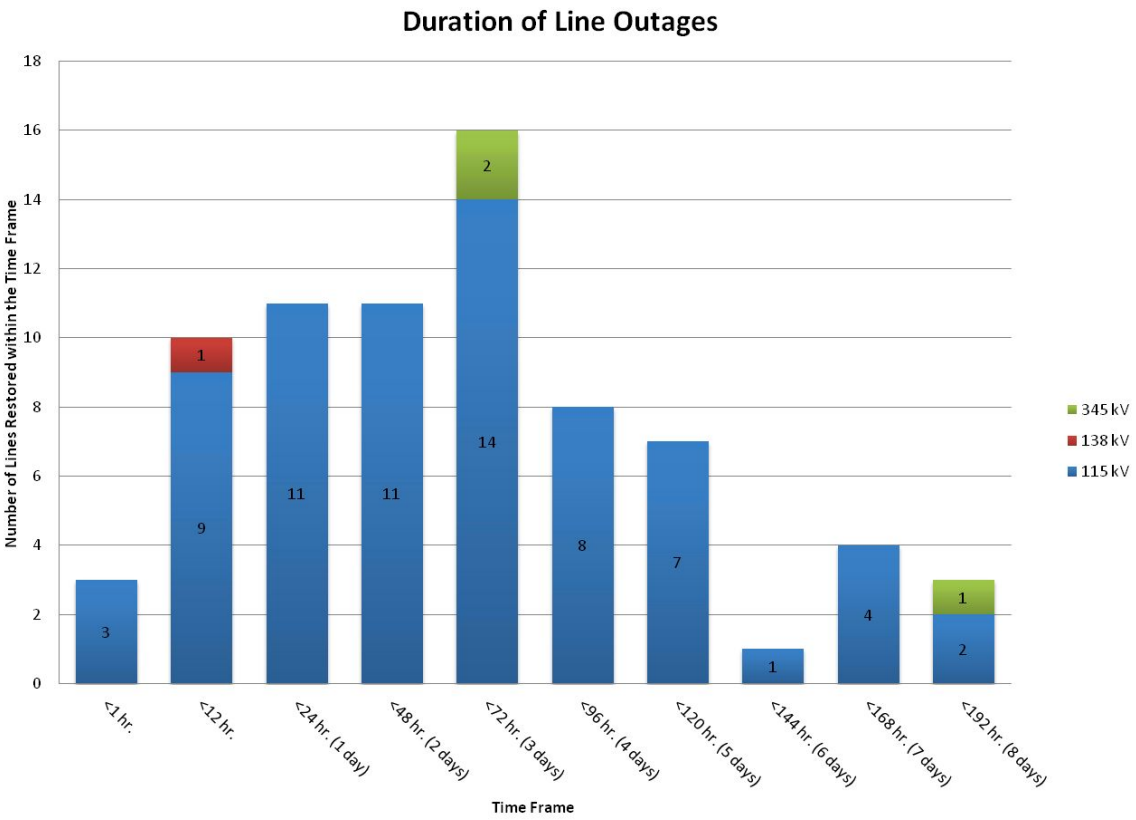



**Figure 10: Duration of Transmission Line Outages**

Utilities faced several physical obstacles in restoring the seven transmission lines that were out of service for six to eight days. Each of these lines or its supporting structures had significant structural damage that required rebuilding. For example, on five of these seven lines, falling trees snapped insulators, cross-arms, and various support structures. In addition, the site of the damage to the 345 kV line that was out of service for nearly eight days was particularly difficult to access. Again, no retail customers were without service due to these seven line outages.

One of the reasons for fast restoration of many transmission lines that caused customer outages is that, in setting priorities for transmission line restoration, utilities focus on restoration of lines that impact customers and are important for grid stability. For example, NU's restoration priorities for the storm event were: (1) transmission lines that would restore more than one substation; (2) transmission lines that impacted one substation; (3) 345 kV lines; (4) lines that served substations with only one live-line feeding them, such that if the live-line went out of service, the substation — and customers served by it — would experience an outage (i.e., single contingency load loss situations); and (5) all other transmission lines.

Staff concludes that restoration of transmission lines was not materially hampered by inadequate utility preparation or response.[59] For example, staff finds that, overall, additional staffing or field crew pre-staging would not have significantly enhanced transmission facility restoration. However, staff — and utilities themselves — recognize that there is room for improvement in storm preparedness. NU informed staff that its restoration of transmission facilities would have happened somewhat faster, albeit minimally, if the company had obtained more outside assistance in advance of the storm, pre-staged some crews, and had access to additional damage assessment equipment (specifically, helicopters and infrared cameras). Therefore, although utility preparation did not pose significant problems for restoration of transmission facilities during this event, staff recommends in Section IX.4 several steps utilities can take to improve preparation for future severe storm events.

[59] Staff recognizes that a number of states are looking into the impact of utility preparation and response on the distribution system as part of their ongoing proceedings relating to the storm's impacts on customers in their state. This report makes no findings regarding impacts of utility preparation and response on restoration of distribution facilities.

# V. Causes of Transmission Facility Outages

As could be expected from a major snowstorm, the vast majority of transmission line outages during the October event were caused by tree contact or the accumulation of ice and heavy, wet snow on transmission conductors.[60] Other causes included losses of source[61] and relay misoperation.

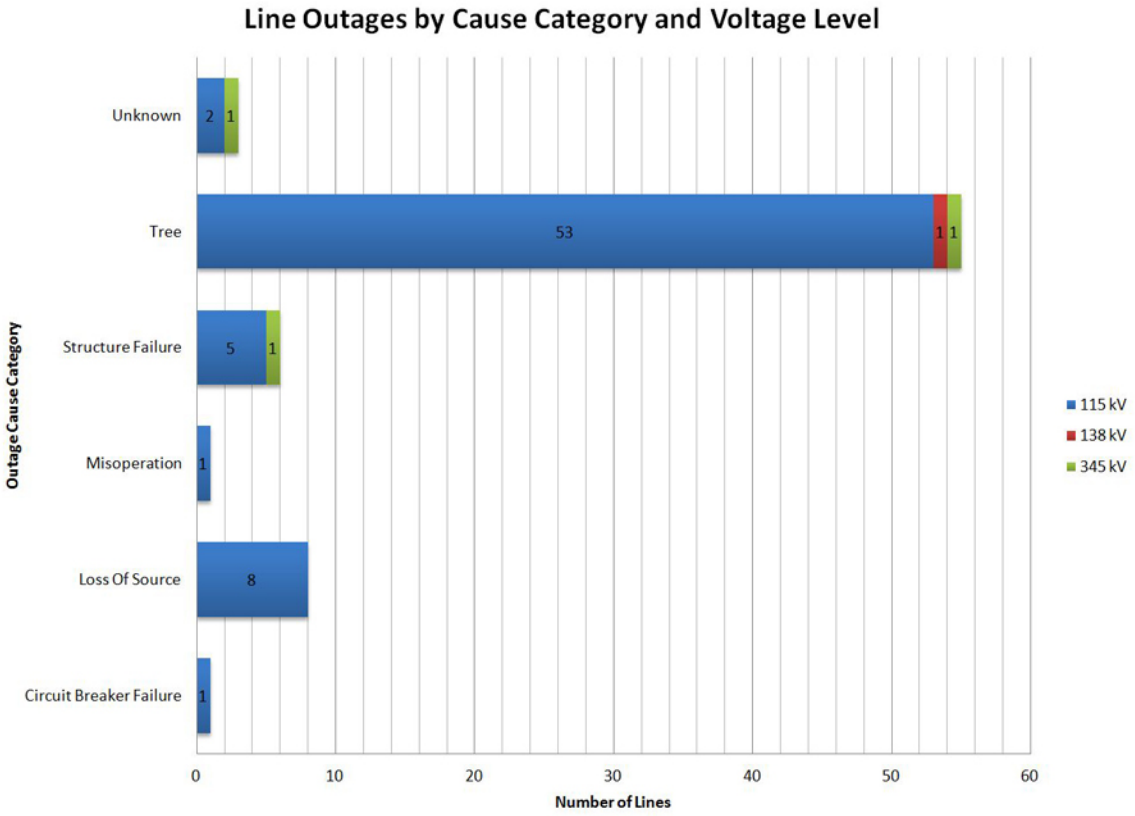



**Figure 11: Line Outages by Cause Category and Voltage Level**

[60] Transmission lines, the wires that carry electricity, are also called conductors.

[61] "Loss of source" outages occur when a connected line, or series of lines, trip and no longer feed an interconnected transmission line, meaning the interconnected line no longer has a source of electrical energy.

## A. Tree Contact

The vast majority of transmission line outages — fifty-five out of seventy-four, or nearly 80% — were caused when snow-weighted leafy trees contacted transmission lines.[62] All but two of these trees were healthy. Twenty-five percent of these trees were located within the utility's right-of-way, and therefore, were likely within the utilities' rights to maintain.

Specifically, thirty-nine transmission line outages resulted from off-right-of-way trees falling onto transmission lines, resulting in loss of power to approximately 84,000 customers. An additional twelve transmission line outages, resulting in 13,000 customer outages, occurred when trees located *inside* a utility's full right-of-way[63] fell into transmission lines. The only tree-caused 345 kV line outage occurred when a sixty-five-foot tall tree located within a full right-of-way (forty-six feet from the nearest transmission line) fell. All of the trees that fell into lines from within the utility's full right-of-way were located outside the area in which the utility performs vegetation management (known as the "maintained right-of-way").[64]

[62] Utilities attributed four of those fifty-five outages to tree contact, but post-storm field inspections by the utilities could not definitively confirm that explanation. Based on review of the data, staff accepts the utilities' attribution of these four outages to tree contact.

[63] For purposes of this report, "full right-of-way" means the portion of land for which a utility has documented legal rights to build and maintain transmission facilities.

[64] As explained in Section VII.B, no Reliability Standard requires that utilities manage vegetation on the entire width of their full rights-of-way. In fact, managing a narrower maintained right-of-way, rather than the full right-of-way, is a relatively common industry practice, though not a best practice.

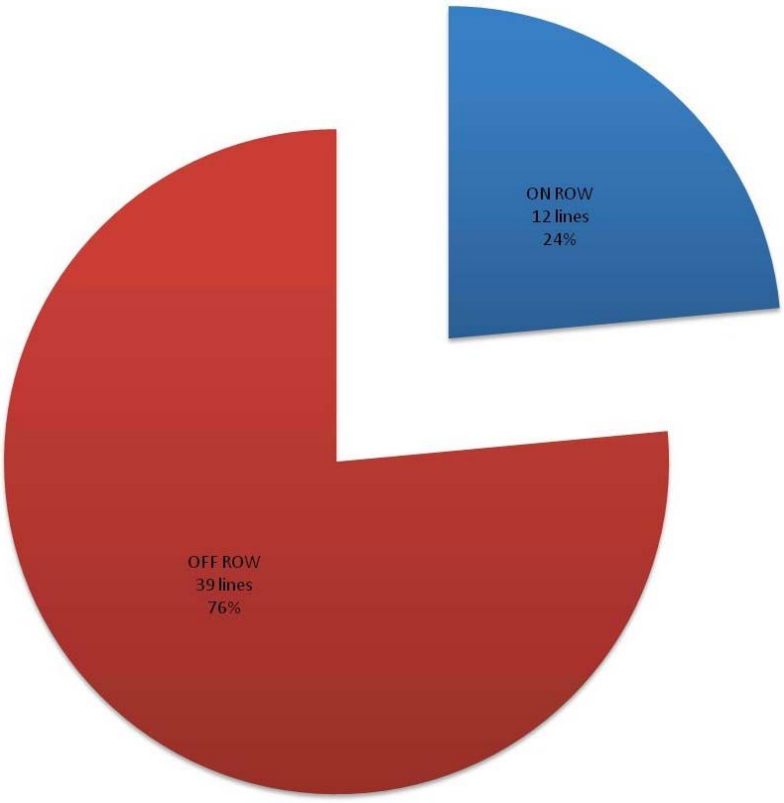



**Figure 12: Fallen Trees Located on Rights-of-Way and Off-Rights-of-Way**

The 115 kV line in the photograph below was forced out of service when several trees, each over sixty feet tall and located twenty to thirty feet outside of the utility's full right-of-way, uprooted and fell onto three separate spans of the line. Transmission lines are not always located in the middle of a right-of-way, but instead often are closer to an edge of the right-of-way. Thus, as is the case here, a tree may be outside the boundaries of a 130 foot wide right-of-way but still less than sixty-five feet from a conductor.



**Figure 13: Trees Fallen on 115kV Line in Connecticut**

*Source: Northeast Utilities*

The line in the photograph below is a 115 kV line in Massachusetts that went out of service when a seventy-five foot tall tree located outside of the 100 foot wide maintained right-of-way, but inside the 200 foot wide full right-of-way, fell onto the line. Because the transmission line was not centered on the right-of-way, the base of the tree, while outside the maintained right-of-way, was only about 30 feet from the nearest conductor.



**Figure 14: Tall Tree Fallen on an 115kV line in Massachusetts**

*Source: Northeast Utilities*

As noted above, data obtained during the inquiry indicates that some of the affected utilities only manage vegetation on narrower maintained rights-of-way rather than their full rights-of-way. For example, one utility's maintained right-of-way widths for 115 kV lines range from 68 feet to 280 feet despite having easements of 88 feet to 325 feet. One 345 kV line is located on a 340-foot wide easement, but only 280 feet of the right-of-way is maintained. Staff finds that the removal of danger trees from full rights-of-way could have prevented the twelve 115 kV transmission line outages (six of which were NPCC-designated BPS elements) that resulted from on-right-of-way tree contact during the October Nor'easter. Preventing those line outages would have avoided approximately 13,000 customer outages.[65] Based on the findings outlined above, staff makes several recommendations regarding right-of-way management in Section IX.

[65] Further complicating right-of-way management is the fact that, for a variety of reasons, some utilities find it difficult to locate the exact edges of many rights-of-way in the field.

## B. Transmission Structure Failures

Extreme weather conditions caused several transmission facilities to break, resulting in transmission line outages. Temperatures during the snowstorm hovered around 32 degrees, which is conducive to the accumulation of ice and snow on transmission lines. The weight of the accumulated ice and snow on conductors, and, in one case, high wind conditions, caused a number of structures — including static wires,[66] conductors, insulators,[67] and cross-arms[68] — to break, resulting in six transmission line outages and approximately 32,000 customer outages. Although a number of the transmission structures that failed were several decades (or even more than fifty years) old, it does not appear, based on data obtained during the inquiry, that these structures were in need of repair before the storm. Data reviewed by staff also indicates that the affected structures had been maintained according to utility plans, which staff finds are consistent with typical utility practice.



**Figure 15: Structure Failure on a 345kV Line in Connecticut**

[66] Static wire (also known as shield wire) is grounded wire that is strung above conductors to protect them from lightning strikes. The static wire is connected to the grounded tower structure and provides a path for lightning to discharge into the earth.

[67] Transmission line insulators are devices used to contain, separate, or support electrical conductors on high-voltage electricity supply networks. Their purpose is to prevent electricity from arcing between conductors or from conductors to the ground.

[68] Cross-arms are the structures located near the top of transmission poles or metal towers that support conductors.

The 345 kV line shown in the photograph above was forced out of service when the weight of ice and heavy, wet snow on conductors damaged a structure and broke a conductor, static wire, cross-arms, guy-wires,[69] and insulators. This photograph shows (in the background) a wood pole where cross-arms and guy-wires have broken and the conductor has fallen to the ground.

## C. Other, or Unknown, Causes

Several transmission line outages were the result of various other, or unknown, causes.

- Eight lines experienced outages as a result of other transmission line failures (i.e., losses of source); these lines were each energized by only one other transmission line, so that when that feeder transmission line failed, the adjacent line also experienced an outage. These loss-of-source transmission line outages caused approximately 16,000 customers to lose power.

- A relay misoperation caused one 115 kV line to be out of service for approximately five hours. As described in footnote 53, a relay misoperation occurs when an automated line monitoring and communications device — a relay — transmits an incorrect signal to a line's breakers, causing the breakers to open when that action is not necessary. In this case, a relay incorrectly detected a problem on the line and forced it out of service. The misoperation did not result in loss of service to any customers.

- One 115 kV line was forced out of service when a circuit breaker component became stuck. The stuck component prevented the breaker from isolating a line that had experienced a fault, resulting in the interconnected 115 kV line losing power. This stuck breaker condition caused about 4,900 customers to lose power for approximately one-and-a-half hours.

- Utility inspections of one 345 kV and two 115 kV transmission lines that experienced outages did not reveal any damage to transmission structures or nearby vegetation, and there is no indication of equipment misoperations. Therefore, the causes of these outages could not be determined by the utility. No customers lost power because of the 345 kV line outage. Approximately 3,800 customers lost service for approximately four to twelve hours as a result of the two 115 kV line outages. Possible causes of those two line outages are undetected tree contacts or arcing across an insulator due to accumulated snow and ice.

[69] A guy-wire is a tensioned cable designed to add stability to structures like utility poles. One end of the cable is attached to the structure and the other is anchored to the ground at a distance from the structure's base.

# VI. Transmission Outages Did Not Destabilize the BPS or Regional Systems

Despite the number — and, in some cases, the duration — of the transmission facility outages caused by the storm, the stability of the BPS and the operations of the transmission systems operated by ISO-New England (ISO-NE) and the New York Independent System Operator (NYISO) were never impaired. This was the result of two main factors: a significant decrease in load resulting from distribution facility damage and, to a lesser extent, preventative measures taken by ISO-NE.

## A. Bulk Power System Impacts

The loss of seventy-four transmission lines — including twenty-three BPS elements — during the October snowstorm did not strain the BPS. There were no Special Protection System[70] operations. System operators were not required to shed load or take other mitigating measures to maintain reliability. All transmission substations that went out of service were restored before their batteries were depleted; thus, the stability and control of the BPS was not threatened due to those substation outages. In short, the transmission system held up well. An important reason for this, however, is that the damaged distribution system significantly reduced the demands placed on the transmission system. The dramatic drop in power usage (also known as "loss of load") that occurred when millions of customers lost power due to distribution facility damage eased the burden on transmission facilities across the Northeast. Under normal load conditions, seventy-four transmission facility outages could have caused swings in voltage and changes in flows requiring system operators to take emergency actions, possibly including load shedding, in order to prevent cascading outages.[71]

Of course, utilities and regulators strive to prevent loss of load, the effects of which can cause significant harm to customers and the economy. Efforts are currently under way in many Northeastern states to prevent significant damage to distribution systems

[70] Special Protection Systems are systems designed to automatically detect abnormal conditions on a transmission system and to take corrective action. *See* NERC, *supra* note 6.

[71] A cascading outage is a sequence of events where an initial event, or set of events, triggers a series of other outages. Cascading outages can result in widespread power outages, such as those that occurred during the 2003 Blackout. However, in some cases, outages can be halted before the sequence results in a major interruption of electricity service.

in future storms in order to minimize customer outages.[72] If these efforts succeed, then load loss resulting from distribution facility damage during severe weather will diminish, which could then increase the demands on transmission lines during and immediately after storm events. Therefore, while it has always been important that utilities take steps to minimize weather-caused transmission line outages, it becomes especially important to do so as efforts are underway to minimize load loss caused by distribution facility damage.[73]

Although the transmission line outages caused by the October snowstorm did not significantly impact the BPS, future storms could cause greater harm to the BPS, and there are valuable lessons that can be learned from this event. Therefore, staff recommends in Section IX that utilities consider targeted actions to better protect transmission facilities. In particular, as discussed below, staff recommends that, where appropriate, utilities take steps to improve maintenance of their rights-of-way and take a targeted approach to enhance management of off-right-of-way danger trees, focusing on protecting lines rated at 200 kV and above, and lower-voltage transmission lines that, if lost, would negatively impact the overall reliability of the Bulk Electric System.

## B. Regional System Impacts

Transmission facility outages during the storm also had no detrimental impact on the ISO-NE or NYISO operations. The ten transmission line outages in the NYISO74 region did not impact the reliability or operation of the NYISO system: no system operating limits were exceeded, no generation was lost, and all applicable reserve margins were maintained. There was no need for NYISO to implement any emergency procedures or alerts.

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[72] For example, the Connecticut legislature recently passed a bill that, among other things, requires the state Public Utilities Regulatory Authority to establish standards for electric utilities in preventing outages, restoring power, trimming trees, and for emergency planning, staffing, mutual aid policies, and power restoration coordination efforts with telecommunication companies. SB 23, Reg. Sess. (Conn. 2012).

[73] As during the October snowstorm, future severe storms events that damage transmission lines will also likely damage distribution lines for the simple reason that large-scale tree failures will not occur only, or even primarily, near transmission lines.

[74] NYISO is the independent, non-profit organization that operates New York State's transmission network, administers its wholesale electricity markets, and serves as the state's NERC-certified Reliability Coordinator. A Reliability Coordinator is "[t]he entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System [in a defined area], 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." NERC, *supra* note 6.

Nearly all transmission facility outages — sixty-four — occurred on the ISO-NE[75] system, but they caused no significant operating impacts. ISO-NE implemented limited procedures to ensure the reliability of the region's transmission system before, during, and after the snowstorm. In anticipation of the snowstorm, ISO-NE implemented an Abnormal Conditions Alert (Master/Local Control Center Procedure 2 (M/LCC-2)) at 1:00 p.m. Eastern Daylight Time (EDT) on Saturday, October 29. This alert protects the stability of the transmission system by requiring market participants to postpone scheduled maintenance, construction, or testing activities in order to maintain reliability in the face of unplanned outages or similar conditions. ISO-NE cancelled the Abnormal Conditions Alert at 11:15 a.m. EDT on Monday, November 7, 2011.

The storm's most significant impact on ISO-NE operations was the significant loss of load caused by the damage to distribution and, to a lesser extent, transmission lines. As a result of the dramatically decreased demand, by Sunday, October 30, ISO-NE had more generation scheduled to run than it needed. In order to reduce the planned power output and keep the system in balance on October 30, ISO-NE twice implemented a Minimum Generation Emergency. This declaration allowed ISO-NE to require generators to operate below the minimum level at which it is economic to run.

Finally, approximately 1,500 MW of generation capacity in ISO-NE went offline during the storm.[76] However, ISO-NE maintained its required reserve margins at all times.[77] All but one of these generation outages were resolved by 9:00 a.m. EDT on October 31. The remaining generator was restored on November 2. The loss of generation capacity had no impact on the stability of the ISO-NE system or the BPS because load levels dropped so significantly during and after the storm that the power the facilities could have produced was not needed.

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[75] ISO-NE is a private, non-profit organization that operates the transmission grid, administers the energy markets, and serves as the NERC-certified Reliability Coordinator for Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.

[76] Twenty-one small units in total were offline; twelve were offline due to loss of transmission lines serving those facilities, seven due to loss of communications for remote start capability, and two due to generator step-up transformer trips.

[77] A generation reserve margin is the amount of generation capacity required to be available at any given time in excess of the amount of generation that is anticipated to be needed to meet actual demand. Reserve margins ensure that there will be enough generation available to meet demand that exceeds projections or to compensate for unanticipated losses of other sources of generation. *See* NERC, *Reliability Indicators: Planning Reserve Margin*, http://www.nerc.com/page.php?cid=4%7C331%7C373.

# VII. Applicability of the Transmission Vegetation Management Reliability Standard

As discussed above, the majority of transmission facility outages and related loss of load that occurred during the October snowstorm were the result of vegetation contact with transmission lines. Therefore, the FERC-approved Reliability Standard most relevant to this event is FAC-003-1 (Transmission Vegetation Management Programs). However, its applicability to the October snowstorm event is limited.

## A. Overview of Reliability Standard FAC-003-1

Reliability Standard FAC-003-178 was developed by the industry with the purpose of preventing outages from vegetation located in transmission rights-of-way and minimizing outages from vegetation adjacent to the right-of-way.[79] The standard requires Transmission Owners to document a transmission vegetation management program (TVMP) that defines a schedule for right-of-way vegetation inspections based on anticipated vegetation growth and other relevant factors.[80] TVMPs must identify two minimum clearances around transmission lines: a "Clearance 2," the minimum distance around transmission lines to be maintained at all times in order to prevent flashover between the lines and vegetation;[81] and a "Clearance 1," the distance around transmission lines utilities will clear to when performing periodic maintenance so as to prevent vegetation from growing into the Clearance 2 space during maintenance intervals.[82] The TVMP also must specify a schedule for, and methods of, vegetation

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[78] Reliability Standard FAC-003-1 was approved by FERC on March 16, 2007, in Order No. 693, FERC Stats. & Regs. ¶ 31,242, and became mandatory and enforceable on June 18, 2007.

[79] Reliability Standard FAC-003-1 (Transmission Vegetation Management Program), at A.3.

[80] *Id*., at Requirement R1.1.

[81] *Id*., at Requirement R1.2.2. Clearance 2 distances must be at least as great as the clearances set forth in IEEE Standard 516-2003, which range from 0.75 to 6.24 meters (2.45 to 22.44 feet) between conductors and grounded objects like vegetation, depending on the conductor's rating. INSTITUTE OF ELECTRICAL AND ELECTRONICS ENGINEERS GUIDE FOR MAINTENANCE METHODS ON ENERGIZED POWER LINES 20, 94 (2003).

[82] Reliability Standard FAC-003-1, at Requirement R1.2. As the Commission explained in Order No. 693, FAC-003-1's clearance requirements mandate that Transmission Owners establish "sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions." Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 729. The Commission noted that "all applicable conditions" does not include the extraordinary circumstances specified in Requirement R3.2, which excludes "natural disasters (including wind shears and major storms) that cause vegetation to fall into the transmission lines from outside the [right-of-way]." *Id*.

inspections.[83] In addition, utilities are required to develop annual plans for vegetation management work to ensure reliability, taking into account various factors, such as anticipated vegetation growth.[84] Finally, Transmission Owners must report certain vegetation-related outages to the relevant Regional Entity.[85]

Unlike the vast majority of Reliability Standards, which apply to all BES facilities (i.e., generally, those operated at or above 100 kV, or otherwise as determined by the Regional Entity), FAC-003-1 applies only to BPS "transmission lines operated at 200 kV and above and to any lower voltage lines designated by the [Regional Entity] as critical to the reliability of the electric system."[86] This means that the Standard does not apply to lines operated at voltages under 200 kV in the NPCC region unless NPCC has designated those lines as "critical" under the Standard. NPCC has not designated any transmission lines rated under 200 kV as "critical" for the purposes of applying FAC-003-1.

When approving FAC-003-1, the Commission acknowledged that, although the proposed Standard gave Regional Entities discretion to designate lines under 200 kV to which the Standard would be applicable, no Regional Entity had actually designated any lower-voltage lines as critical for that purpose.[87] The Commission expressed the concern that a bright-line 200 kV threshold for application of the Standard would "exclude a significant number of transmission lines that could impact Bulk Power System reliability."[88] However, in response to industry concerns that, among other things, the costs of expanded applicability to sub-200 kV facilities could outweigh the benefits, the Commission did not require NERC to revise FAC-003-1 immediately. Instead, it directed NERC to "revise it through the Reliability Standards development process, with the expectation that the applicability of this Reliability Standard will expand to include additional facilities that impact reliability that currently are not covered by this Reliability Standard."[89]

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[83] Reliability Standard FAC-003-1, at Requirement R1.

[84] *Id.*, at Requirement R2.

[85] *Id.*, at Requirement R3.

[86] *Id.*, at A.4.

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

[88] *Id.*

[89] *See id.* P 710.

Because NPCC does not apply FAC-003-1 to any sub-200 kV BPS elements, FAC-003-1 only applied to one line — a 345 kV line in Connecticut — that was forced out of service due to tree contact during the October snowstorm.[90] That line's outage did not result in any customer outages. Thus, although the October snowstorm outages were almost entirely caused by vegetation contact, the Transmission Vegetation Management Reliability Standard applied to only *one* of the fifty-five transmission lines forced out of service by tree contact (and applied to none of the distribution lines damaged in the storm).[91] To the extent that a state does not have vegetation management standards governing transmission lines operated over 100 kV[92] and the relevant Regional Entity has not designated lines operated under 200 kV as critical to the region's reliability for the purpose of applying FAC-003-1, lines operated between 100 kV and 200 kV in that state would not be covered by any federal or state vegetation management standard.

## B. FAC-003-1's Scope

If FAC-003-1 had applied to all of the transmission facilities impacted by tree contact during the October snowstorm, compliance with the Standard with respect to those lines may not have prevented the storm's vegetation-caused transmission line outages. This is because: (a) the majority of outages were caused by trees that fell onto transmission lines from outside the utility's right-of-way, and FAC-003-1 does not specifically address off-right-of-way vegetation management; and (b) FAC-003-1 does not dictate specific right-of-way management practices, including how utilities should manage on-right-of-way danger trees.

First, FAC-003-1 does not specifically address management of vegetation located outside a utility's right-of-way. Thus, even if the Standard had applied to all

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[90] Two other lines that experienced outages during the October snowstorm are operated at over 200 kV, and therefore subject to FAC-003-1, but those outages were not caused by vegetation contact.

[91] On December 21, 2011, NERC filed with FERC a proposal to replace FAC-003-1 with a new standard, FAC-003-2. Among other things, FAC-003-2 would revise the Standard so that it would be applicable to all transmission lines operated at or above 200 kV and any line that is an element of an Interconnection Reliability Operating Limit (IROL) or a Western Electric Coordinating Council (WECC) Transfer Path. N. Am. Elec. Reliability Corp., Petition, Docket No. RM12-4-000 (filed Dec. 21, 2011). However, this expanded applicability would not have significantly increased the Standard's impact on lines forced out of service by tree contact during the October snowstorm because only eight of those 115 kV or 138 kV lines are IROL elements (none are WECC Transfer Paths). Moreover, the proposed FAC-003-2's requirement that no vegetation come into contact with lines governed by the Standard does not apply when the vegetation contact is caused by major storms. This report does not offer any views on proposed FAC-003-2, which is currently under review by the Commission.

[92] *See, e.g.*, N.Y. Comp. Codes R. & Regs. Title. 16 §§ 84.2, 84.3; Cal. Gen. Order 95, Rule 35.

transmission lines impacted by vegetation during the October storm, it would not have addressed the condition — tall trees growing outside of utilities' rights-of-way — that caused over half of all storm-related outages. One reason FAC-003-1 does not explicitly address off-right-of-way vegetation management is that land adjacent to rights-of-way is typically not owned by the utility, and state laws usually limit utilities' ability to prune or remove trees on property they do not own. Although state laws differ, generally speaking, a utility may not remove a tree (including a danger tree) located outside of its right-of-way without the property owner's consent.[93] Moreover, obtaining permission to remove off-right-of-way trees can be complicated and difficult.

When utilities and state agencies set policies and make decisions regarding removal of danger trees outside the right-of-way, they must consider a number of factors. Reliability of the transmission system, and, in particular, preserving the stability of the BPS, is a central concern. However, environmental issues, property rights, viewsheds, and cost also play an important role. In heavily forested regions like New England, even if possible, the reliability benefits of removing all danger trees from outside utilities' rights-of-way often would not outweigh the costs of doing so.[94] For example, Northeast Utilities provided staff with an estimate that there are some 800,000 danger trees along the edges of its rights-of-way, and that removing them would cost approximately $400 million.[95] Notwithstanding competing policy concerns, off-right-of-way tree fall-ins were the leading cause of transmission line outages during the October snowstorm, and, in general, some off-right-of-way danger trees can pose a threat to reliability. Therefore, staff makes a recommendation in Section IX that utilities should re-evaluate, and work to enhance, their off-right-of-way vegetation management.

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[93] *See, e.g.*, N.H. Rev. Stat. Ann. § 231:172(I) (electric utilities must obtain consent of the landowner to prune trees outside of the right-of-way); *see also Tree Trimming FAQs*, PUBLIC SERVICE OF NEW HAMPSHIRE, http://www.psnh.com/CustomerSupport/Home/Tree-Trimming-FAQs.aspx (explaining procedures for obtaining consent of tree owners before performing trimming maintenance). In some circumstances, if a utility provides notice of its intent to remove a tree and the landowner does not object, the utility may proceed without specific permission. *See, e.g.*, N.H. Rev. Stat. Ann. § 231:172(II)(b) (stating that the utility may perform the work without permission if the tree owner does not request personal consultation after receiving notice). In some states, there are expedited procedures for obtaining permission to remove "hazard trees" — trees that present an imminent danger to transmission lines because they are damaged or diseased. *See, e.g.*, Mass. Gen. Laws Ann. ch. 87 § 14(b), (c) (permitting electric utilities to file hazard tree removal plans for approval by the tree warden to avoid otherwise applicable restrictions on tree removal).

[94] As ISO-NE has stated, "[t]he political, social and environmental expectations placed on utilities in New England prevent the clearing required to guarantee total system protection from falling trees. In severe weather events (hurricanes, micro bursts, tornadoes and ice storms) trees may fail and fall into lines." ISO-NE, OPERATING PROCEDURE 3 Appendix C (2005).

[95] Of course, the monetary and non-monetary costs of danger tree removal must be weighed against, among other things, the often high costs of transmission outages.

Second, while FAC-003-1 does require utilities to maintain plans and procedures to address vegetation to meet its Clearance 1 requirements, and utilities have considerable flexibility in designing transmission vegetation management programs as long as utilities are compliant with the FAC-003-1 requirements, the Standard does not specifically dictate how utilities should manage danger trees that are outside of Clearance 1 but within the right-of-way. Thus, utilities may maintain vegetation clearances on less than the full right-of-way, which can increase the number of danger trees within the right-of-way.[96]

FAC-003-1 does recognize that the American National Standard Institute's (ANSI) Standard A300, which provides guidelines for integrated vegetation management on electric utility rights-of-way,[97] is an industry best practice.[98] ANSI A300 does not specifically prohibit growth of danger trees on a right-of-way, but it does explain that the "wire zone-border zone" vegetation management method, where the full right-of-way is managed in order to prevent the growth of danger trees, "is a proven method that ensures the reliability of electric supply lines."[99] The wire zone-border zone method allows very low-growing vegetation such as grasses and other groundcover species in the area under and immediately around transmission structures (the "wire zone") and permits short-growing vegetation like shrubs and short trees from the outer edge of the wire zone to the edge of the utility's full right-of-way (the "border zone").[100] The following drawing illustrates the wire zone-border zone concept.

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[96] Staff notes that no registered entity has been charged with a violation of FAC-003-1 as the result of a healthy tree falling onto (as opposed to growing into) a transmission line.

[97] Integrated vegetation management (IVM) is "[a] system of managing plant communities in which compatible and incompatible vegetation is identified, action thresholds are considered, control methods are evaluated, and selected control(s) are implemented to achieve a specific objective." ANSI A300, *supra* note 14 at 72.

[98] Reliability Standard FAC-003-1, at Requirement R1 n.1.

[99] ANSI A300, *supra* note 14 at 75.2, Annex A.

[100] ANSI A300, *supra* note 14; RANDALL H. MILLER, BEST MANAGEMENT PRACTICES: INTEGRATED VEGETATION MANAGEMENT 17 (2007) (companion publication to ANSI A300).

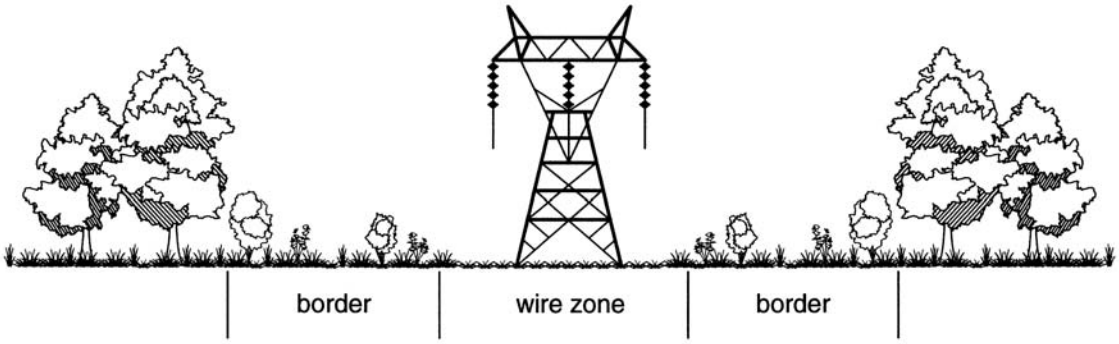



**Figure 16: Wire Zone-Border Zone Illustration**

*Source: UVM Final Report, infra note 109*

FAC-003-1's focus on maintaining clearances through a specific method like the recognized wire zone-border zone best practice reflects an emphasis on preventing vegetation from growing or swaying into conductors (or conductors swaying or sagging into vegetation) rather than vegetation breaking and falling into conductors, especially during severe storms.[101] Thus, to minimize the damage caused by similar events in the future vegetation management requirements would need to include a requirement to address at least those danger trees growing within the right-of-way.

[101] Indeed, the genesis of FAC-003-1 was the major blackout that occurred on August 14, 2003, which was caused in significant part by unmanaged vegetation that, due to growth and line sag, contacted several 345 kV lines and precipitated cascading outages throughout the eastern United States and Canada. *See* U.S.-CANADA POWER SYSTEM OUTAGE TASK FORCE, *supra* note 12. Proposed FAC-003-2 requires that Transmission Owners manage vegetation in order to prevent *any* vegetation from making contact with transmission lines – including fall-ins. *N. Am. Elec. Reliability Corp.*, Petition, Docket No. RM12-4-000, at Proposed Standard FAC-003-2, R1, R2 (filed Dec. 21, 2011). However, as stated in note 91, the proposed standard would *not* apply to vegetation contact in "circumstances that are beyond the control of a Transmission Owner," including natural disasters such as "major storms as defined either by the Transmission Owner or an applicable regulatory body . . . ." *Id.*, at R1 n.2. As previously noted, this report takes no position on proposed FAC-003-2.

# VIII. Outage Reporting Provides Limited Information

During and after the storm, two Reliability Standards – FAC-003-1 and EOP-004-1 – required that entities report some information about their outages to either NERC or NPCC. However, those requirements, and the responses provided by most affected utilities, resulted in FERC and NERC initially receiving limited information about the event. Based on the findings in this Section, staff makes recommendations in Section IX for improved or enhanced reporting of certain outage information.[102]

Standard FAC-003-1 requires Transmission Owners to report on a quarterly basis to Regional Entities such as NPCC sustained vegetation-caused outages on lines subject to that Standard,[103] and NPCC guidance also instructs transmission owners to report vegetation-caused outages on any BPS elements operated under 200 kV.[104] However, outages caused by off-right-of-way tree contacts during natural disasters, including major storms, do not have to be reported under FAC-003-1.[105] While NERC obtains certain data about outages through other reporting mechanisms, there are no data reporting requirements in place that mandate the reporting of all the transmission facility outages that occurred in the October storm. Nor were all such outages, in fact, reported to NERC. Thus, utilities were not required by FAC-003-1 to submit information on the October storm's BPS element outages caused by off-right-of-way tree fall-ins.

Staff gathered substantial information about these outages during the inquiry, but is concerned that information about off-right-of-way tree fall-ins during other weather

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**102** This report's findings and recommendations regarding reporting address only issues related to reporting outage information to FERC, NERC, or the Department of Energy (DOE). We do not address issues related to reporting distribution facility or customer outages to state regulators. However, staff notes that there have been calls to improve the consistency of distribution facility outage reporting. *See* MASSACHUSETTS INSTITUTE OF TECHNOLOGY, *The Future of the Electric Grid*, 9 (2011), *available at* http://web.mit.edu/mitei/research/studies/the-electric-grid-2011.shtml ("Most outages occur within distribution systems, but only 35 U.S. states require utilities to report data on the impact of all outages on consumers, and reporting standards and practices differ. It is accordingly impossible to make comprehensive comparisons across space or over time.").

**103** Reliability Standard FAC-003-1, at Requirement R3.

**104** NPCC, COMPLIANCE GUIDANCE STATEMENT ON REPORTING OF TRANSMISSION OUTAGE RELATED TO VEGETATION CONTACT (rev. Oct. 3, 2008), *available at* https://www.npcc.org/Compliance/Compliance%20Guidance%20Statements/Forms/Public%20List.aspx.

**105** Reliability Standard FAC-003-1, at Requirement R3.2.

events may not be reported. The weather exception prevents regulators from obtaining a key source of information about the extent and severity of these types of outages. Better information would allow policymakers to understand the scope and impacts of weather-caused off-right-of-way tree fall-ins, and to assess whether regulations or guidance should be formulated to address those outages.

Second, staff finds that, during and after the October snowstorm, affected entities did not always provide thorough information in the disturbance reports they were required to file with NERC under Reliability Standard EOP-004-1. That Standard mandates that registered entities submit completed disturbance report forms — either the DOE Electric Emergency Incident and Disturbance Report (Form OE-417) or NERC's Interconnection Reliability Operating Limit and Preliminary Disturbance Report — after certain events, including those where there is significant loss of load.[106] Initial Form OE-417s must be submitted to DOE and NERC within an hour of the disruption, and, at the time of the October storm, final reports providing complete disruption information were required to be filed within 48 hours of the event.[107] However, the majority of the OE-417 forms submitted by utilities during and after the October snowstorm did not provide enough information to allow for a useful initial analysis of the event. For example, many final reports did not include full narrative descriptions of events, or include the voltage of transmission lines that experienced outages. This lack of thoroughness, particularly in the final reports, made it difficult for FERC and NERC staff to ascertain the exact nature of the impact of the storm on the affected systems.[108]

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[106] Reliability Standard EOP-004-1 (Disturbance Reporting), at Requirement R3.

[107] *Id.*, Attachment 2. As of January 1, 2012, the forty-eight-hour reporting requirement for final reports was extended to seventy-two hours.

[108] The inconsistency and incompleteness of information regarding BPS outages was also noted in the MIT report on the future of the electric grid: "At the bulk power level, data on major disturbances and unusual occurrences have been reported to the U.S. Department of Energy (DOE) since the 1970s and to the North American Electric Reliability Corporation (NERC), which has responsibility for the reliability of the bulk power system, since 1984. However, these data are not consistent, complete, or necessarily accurate, and they cannot reliably be used to assess changes in the reliability of the bulk power system over time." *See* MASSACHUSETTS INSTITUTE OF TECHNOLOGY, *supra* note 102, at 9.

# IX. Recommendations

The October 2011 Nor'easter was a rare storm that, due to a number of circumstances — record amounts of heavy wet snow, trees that had not lost most of their leaves, and unusually saturated ground — had severe and widespread impacts on the electricity infrastructure in the Northeast. Staff recognizes the unusual aspects of this weather event. Nonetheless, based on information gathered and findings made during the inquiry, staff concludes there are a number of "lessons learned" that, if implemented, could improve reliability during future storms and similar weather events. Accordingly, staff makes the following recommendations with regard to transmission facilities.

### • *Vegetation Management Recommendations*[109]

By far, the leading cause of transmission line outages during the October snowstorm was trees or tree branches falling onto power lines from outside and inside utilities' rights-of-way.[110] Staff therefore recommends that utilities take the following targeted steps to enhance their management of danger trees both on and off their rights-of-way in order to reduce these types of outages.[111]

#### 1. Where Appropriate, Utilities Should Take Targeted Steps to Address Off-Right-of-Way Danger Trees

As noted above, off-right-of-way tree fall-ins accounted for about half of the storm's transmission line outages, and nearly 75% of all confirmed vegetation-caused outages. Off-right-of-way danger trees are a particular threat to reliability in New England, where there may be hundreds of danger trees along one span of a transmission line. Staff

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[109] In response to the 2003 Blackout, FERC commissioned a separate vegetation management report to support the federal investigation into that event. The result was the Utility Vegetation Management Final Report, completed by CN Utility Consulting, LLC and published in 2004. STEPHEN R. CIESLEWICZ & ROBERT R. NOVEMBRI, UTILITY VEGETATION MANAGEMENT FINAL REPORT (March 2004) [hereinafter "UVM Final Report"], *available at* http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/uvm-final-report.pdf. The recommendations related to vegetation management in this report are similar to several of the vegetation management recommendations made in the UVM Final Report.

[110] In fact, the majority of vegetation-related outages in the United States are caused by trees or portions of trees falling into lines from distances outside of normal clearing zones (i.e., Clearance 1 or Clearance 2 distances). *See* NERC, *Vegetation Management Reports*, http://www.nerc.com/page.php?cid=3|26.

[111] Staff recognizes the sensitivity of vegetation management issues and the difficulty of expanding rights-of-way and more effectively maintaining them. However, these difficulties must be balanced against the reliability and safety benefits of improved right-of-way management.

recognizes that in most cases utilities are not free to unilaterally remove off-right-of-way trees, that the process for obtaining permission to do so is frequently difficult and costly, and that tree removal often faces significant landowner and public opposition. Moreover, the costs of indiscriminate, widespread removal of off-right-of-way danger trees may outweigh the reliability benefits of doing so.

Taking all these factors into consideration, staff recommends that, where appropriate, utilities follow a targeted approach to enhancing their off-right-of-way danger tree management, focusing on protecting lines operated at 200 kV and above, and lower-voltage transmission lines that, if lost, would negatively impact the overall reliability of the Bulk Electric System. Utilities should analyze their transmission systems in order to identify danger trees — particularly those species of trees that have a tendency to fail — that could impact critical transmission lines. After performing this analysis, utilities should work with affected property owners, state regulators, and local communities to develop a strategy for managing those trees that pose the greatest threat to those facilities. In addition, if state laws or policies significantly impact utilities' ability to manage off-right-of-way danger trees that could impact these critical facilities, utilities should work with stakeholders and state and local governments to develop solutions that reduce risk to those lines.

### 2. Utilities Should Employ Recognized Best Practices in Managing Rights-of-Way Where Feasible

Staff found in Section V.A that roughly 25% of the confirmed vegetation-related transmission line outages during the October event were caused by trees that fell into transmission lines from inside a utility's full right-of-way. These on-right-of-way trees were all located outside the utility's maintained right-of-way. Based on this finding, staff recommends that, where possible and practical, utilities implement the industry best practice of ensuring that danger trees are not present within their full rights-of-way.[112] In particular, to the extent a utility manages vegetation only on maintained rights-of-way rather than full rights-of-way, it should work toward reclaiming the full right-of-way width where feasible.[113]

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[112] Staff recognizes that there are a number of ways to achieve this result. The wire zone-border zone right-of-way maintenance method, discussed in Section VI, is recognized as highly effective in protecting against on-right-of-way tree contact and generally maintaining reliability. Selection of the most appropriate maintenance method for any given right-of-way should be made by qualified vegetation management personnel.

[113] Maintaining narrower areas within a full right-of-way is not an uncommon practice in the industry and occurs for a variety of reasons, some of which are outside the control of the utility. However, it is not a best practice.

Two key components of reclaiming and maintaining full rights-of-way are (1) knowing the exact boundaries of that area and (2) being able to identify those boundaries in the field. This is not always easy, given that traditional markers (such as wooden stakes or iron plates) can deteriorate or get lost during four-plus year vegetation management cycles. However, technologies such as Light Detection and Ranging (LiDAR) and Global Positioning Systems (GPS) can help utilities accurately and more permanently identify right-of-way boundaries on the ground. Staff recommends that, over time, utilities work toward employing technologies that will allow them to track the exact boundaries of all of their transmission rights-of-way and locate those boundaries in the field.

Staff recognizes there are a number of circumstances where utilities may be unable to completely prevent the presence of danger trees within full, or even maintained, rights-of-way through implementation of the wire zone-border zone management or other, similar techniques, and that utilities have been, and must continue to be mindful, of these circumstances.[114] For example, utilities may be prohibited by state law from removing certain vegetation on their rights-of-way in environmentally sensitive areas, or may be required to maintain on-right-of-way vegetation in order to partially shield power lines from view.[115] Removal of danger trees also may not be possible where the easement establishing the utility's right-of-way explicitly limits, or does not clearly permit, vegetation management in the full easement area. Even where the easement gives a utility rights to manage vegetation across the entire right-of-way, past practices (for example, years of permitting landowners to grow tall trees inside the right-of-way), landowner objections, or public sentiment opposing the maintenance of wide rights-of-way may make it difficult to employ the wire zone-border zone method or otherwise to remove danger trees. Staff also recognizes that reclaiming rights-of-way that are not currently being fully managed can be expensive, time consuming, and difficult. However, staff finds that consistently maintaining the full right-of-way would reduce the number of danger trees near transmission lines.[116]

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**114** *See, e.g.,* CIESLEWICZ & NOVEMBRI, *supra* note 109, at 21 (recognizing that there are locations where implementing the wire zone-border zone model is not practical); MILLER, *supra* note 100, at 18-19 (same).

**115** *See generally*, CIESLEWICZ & NOVEMBRI, *supra* note 109, at 15-16.

**116** Staff recognizes that, in some instances, removing certain tall-growing trees from the interior edge of the full-right-of-way may expose weaker, top-heavy danger trees on the exterior edge, posing more of a risk of a tree falling into the transmission facilities.

Utilities should, of course, take these circumstances into account when evaluating their right-of-way management policies to specifically address danger trees. Staff recommends that utilities: (a) identify the areas where elimination of danger trees inside the full right-of-way is possible given site-specific circumstances and (b) evaluate whether danger tree removal/right-of-way reclamation would increase reliability and be feasible. Once rights-of-way that are appropriate for removing danger trees are identified, utilities should prioritize their efforts, focusing first on rights-of-way surrounding lines that are rated at or above 200 kV, and lower-voltage transmission lines that, if lost, would negatively impact the overall reliability of the Bulk Electric System.

In sum, in order to improve reliability during future major storms, staff recommends that, where possible, utilities develop and implement plans to ensure that danger trees are not located within their full rights-of-way.[117]

### 3. Utilities Should Lay the Foundation for Effective Vegetation Management When Establishing New Rights-of-Way

Preventing fall-ins from both inside and outside the right-of-way is easier if utilities consider vegetation management needs when siting new transmission lines and acquiring new easements. Therefore, staff recommends that utilities carefully assess vegetation and growth rates in the area of planned lines in order to establish the appropriate right-of-way width. For example, if native trees have a mature height of 100 feet, the easement should cover an area wide enough to ensure that existing and future trees outside of the right-of-way will not fall into the facilities.[118]

In addition, utilities should ensure that easement documents protect the utility's ability to ensure safe and reliable transmission of electricity. New easements should clearly provide the utility with rights to manage the full easement in order to prevent the presence of danger trees inside the right-of-way. In addition and where possible, new easements should give the utility the ability to remove danger trees outside of the right-of-way.

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[117] To be clear, preventing the presence of danger trees within the right-of-way does *not* mean that full rights-of-way need to be (or should be) clear-cut. This recommendation is focused on ensuring that, where feasible, danger trees – those trees that could fall into a transmission line or structure – are not present within rights-of-way because they can threaten reliability. Many types of trees growing within rights-of-way do not constitute danger trees.

[118] *See* CIESLEWICZ & NOVEMBRI, *supra* note 109, at 71.

• ***Other Recommendations***

## 4. Utilities Should Evaluate and, As Needed, Enhance Their Storm Preparedness and Response Plans

As explained in Section III, the October snowstorm exceeded forecasts, and many utilities scrambled — often at the last minute — to assemble adequate response personnel, especially field crews. Although these manpower and related issues did not significantly hinder restoration of transmission line outages or unduly prolong transmission-caused customer outages, the event revealed potential areas of improvement in preparation for future storms. Thus, staff recommends that utilities evaluate their severe storm preparation and response plans to ensure they are flexible and scalable enough to quickly respond to events that are more severe than predicted. For example, utilities should: (a) clearly define how and when they will request outside assistance, through mutual aid or outside contractors; (b) be prepared for regional mutual assistance crews to be unavailable when a weather event is predicted to impact many states, either by requesting mutual aid from other regions early on or retaining additional local contractors to make up for the lack of immediately available mutual assistance; (c) have a policy in place regarding if, when, and where pre-staging will occur; (d) have the ability to, and procedures regarding, reservation of equipment, such as helicopters and infrared cameras, in advance of major storms in order to ensure prompt assessment of transmission system damage; and (e) in regions where extreme weather events occur, and especially where they are becoming more common, retain experienced weather personnel with the responsibility to predict likely impacts of weather events, taking into account service-territory-specific conditions.

## 5. Utilities Should Report All Vegetation-Caused BES Facility Outages to NERC

As discussed in Section VIII, even though off-right-of-way tree contact during severe storms is a frequent cause of transmission line outages, FAC-003-1 does not require utilities to report those outages to Regional Entities or NERC. Moreover, the Standard does not require the reporting of vegetation-caused sustained outages on BES transmission lines not subject to FAC-003-1 (i.e., those operated at voltages below 200 kV or lower-voltage lines not designated as critical by a Regional Entity). To ensure that regulators have sufficient information to allow them to make informed policy decisions about these types of outages, staff recommends that all tree contact-caused BES facility outages be reported to NERC.

## 6. Disturbance Reports Should Be Clear and Complete

Section VIII finds that although a number of entities were required by Reliability Standard EOP-004-1 to file preliminary and final disturbance reports related to the October snowstorm outages, many of the filed forms were not completed thoroughly. This lack of thoroughness made it difficult to quickly ascertain the impact of the storm on the affected systems. Staff recommends that, where possible, all entities required to file disturbance reports under EOP-004-1 promptly provide thorough, descriptive, high-quality information in the initial reports as it becomes available to them. With regard to the final disturbance reports, utilities should ensure their responses are comprehensive, providing all the relevant information in their possession.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# NERC News

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## Headlines

### FERC-NERC Release Joint Report on Northeast Snowstorm

Damaged electric distribution lines were the major cause of the widespread Northeastern customer outages during the October 2011 snowstorm, but utilities can apply lessons learned from the storm to improve performance and enhance reliability of their transmission lines in advance of the next storm, staff of the Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) said.

Staff of both FERC and NERC – FERC is the federal agency that oversees reliability of the transmission grid and NERC is the national electric reliability organization certified by FERC – issued a joint report on the transmission outages today. The joint inquiry focused on determining the causes of the transmission facility outages and on the steps utilities could take to improve their performance in maintaining grid reliability during the next large snowstorm or similar weather event. The purpose of the inquiry was not to investigate whether particular companies violated FERC-approved reliability standards or other applicable statutes and regulations.

Today's report finds that problems along the transmission system caused less than 5 percent of customer outages at the peak of the October 29-30 storm, which left more than 3.2 million homes and businesses without power. The report says 74 transmission lines and 44 transmission substations experienced outages; most lasted fewer than two days and none lasted more than five days.

Nearly three-quarters of the transmission line outages occurred when healthy trees, most located outside of utility rights-of-way, fell onto the lines uprooted by the weight of the snow compounded by the soft, wet ground. The report offers several recommendations to help reduce the adverse impacts of future weather events on the transmission system, including:

- Where appropriate, take targeted steps to address off-right-of-way danger trees;
- Employ best practices in managing vegetation on full rights-of-way;
- Lay the foundation for effective vegetation management when establishing new rights-of-way;
- Enhance storm preparedness and response plans as needed.

The joint report also recommends increasing the reporting of vegetation-caused outages and improving the content of required disturbance reports.

### FERC Staff Releases Contested Audit Report; NERC Disappointed at Lack of Chance to Resolve Differences

The North American Electric Corporation (NERC) is disappointed in the unwillingness of the Office of Enforcement of the Federal Energy Regulatory Commission (FERC) to work toward resolution of a recent "economy and efficiency" audit of NERC, choosing instead to litigate many aspects of the audit.

The FERC Office of Enforcement released an "economy and efficiency" audit of NERC that began in August 2011. On April 23, 2012, NERC responded to a draft of the audit report with constructive changes, factual corrections and a proposal to support, in modified form, 34 of the 42 recommendations. A meeting with FERC's senior staff also was requested to discuss the legal and policy issues raised in the draft report. A copy of NERC's response is provided on the NERC website.

Instead, the Office of Enforcement has declined to negotiate as is the norm and, instead, opted to initiate litigation on portions of the audit findings and recommendations. NERC is disappointed at this audit process and is dismayed that the Office of Enforcement, acting under delegated authority, declined the request to work toward resolution of these matters.

"NERC regrets that FERC staff declined to meet to resolve areas of disagreement," said Gerry Cauley,

president and chief executive officer at NERC "We provided constructive suggestions in our April 23 response to questions raised in the draft audit report."

Although we understand that all FERC commissioners will ultimately review n y contested issues, we regret that a litigation process was chosen rather than our invitation to work out the differences through the standard method of negotiation," said David Cook, general counsel for NERC. "We are not aware of another case where FERC staff declined an invitation to meet to discuss the company's response to a draft audit report."

As explained in NERC's detailed response to the draft report, many of the disagreements that arose in the audit were related to the fact that audit staff did not assess compliance with FERC rules, but rather its own view of "economy and efficiency" concerns related to NERC's internal processes. By divorcing the audit from compliance with specific rules, this meant that audit staff had no objective criteria upon which to base the audit. The audit team also had proposed limitations on the scope of NERC's activities that are contrary to previous Commission orders.

NERC is willing to work with the audit staff toward a resolution, and we regret that they have declined to meet to discuss our response to the draft report. NERC welcomes the opportunity to contest the remaining issues in an open and transparent process.
Other documents: NERC redline of draft audit report and NERC recommendations comparison.

## FERC-NERC Staff Report on September 2011 Blackout Calls for Improved Planning

Staff of the Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) said the September 2011 blackout that left 2.7 million customers in Southern California, Arizona and Baja California without power stemmed from operating in an unsecured state due to inadequate planning and a lack of observability and awareness of system operating conditions on the day of the event.

A joint FERC-NERC staff report on the Sept. 8 blackout, issued today after a nearly eight-month inquiry, recommends that transmission operators and balancing authorities improve how they plan for operations to account for the status of facilities outside their individual systems, the effect of external operations on their own systems and how operation of transmission facilities under 100 kiloVolts (kV) can affect the reliability of the bulk power system.

"This report highlights the growing need for more coordination of grid operations in the West," FERC Chairman Jon Wellinghoff said. "Implementing the recommendations in this report will assist in enhancing the planning and system awareness measures that are necessary to operate an efficiently integrated bulk power system, and reduce costs to consumers from these types of outages that could continue if operational efficiencies are not improved."

"This event underscores how complex and interdependent our North American electric systems are and the critical importance of information sharing, communications, system studies and coordinated operations among all interconnected systems," said Gerry Cauley, president and CEO of NERC. "Transmission operators, Balancing Authorities and Reliability Coordinators must work together to effectively manage this complex system. I would like to recognize the effective collaboration between FERC and NERC staff during the course of this inquiry"

"Today's report provides a series of lessons learned from the September 2011 event that is available to industry for use as a tool to improve their operations and planning of the grid," FERC Commissioner John Norris said. "My hope is that the findings and recommendations in this report will be utilized to the broadest extent possible in order to enhance the reliability and efficiency of the Bulk Power System."
The inquiry was initiated to determine how the blackout occurred and to make recommendations to avoid similar situations in the future. FERC and NERC staff used on-site interviews, sophisticated computer modeling, event simulations and system analysis to make the determination that entities responsible for

planning, operating and monitoring the bulk power system were not prepared to ensure reliable operation or prevent cascading outages in the event of a single contingency: the loss of Arizona Public Service's (APS) Hassayampa-North Gila 500 kV transmission line.

That line loss itself did not cause the blackout, but it did initiate a sequence of events that led to the blackout, exposing grid operators' lack of adequate real-time situational awareness of conditions throughout the Western Interconnection. More effective review and use of information would have helped operators avoid the cascading blackout. For example, had operators reviewed and heeded their Real Time Contingency Analysis results prior to the loss of the APS line, they could have taken corrective actions, such as dispatching additional generation or shedding load, to prevent a cascading outage.

The report recommends that bulk power system operators improve their situational awareness through improved communication, data sharing and the use of real-time tools. It also recommends that:

- System planners and operators recognize, study and incorporate the effects of sub-100 kV systems on bulk power system reliability into their planning and operations;
- The Western Electricity Coordinating Council (WECC) recognize and study Interconnection reliability operating limits;
- Transmission Owners and Operators review overload protection relay settings to give them more time to mitigate overloads;
- Transmission Operators and WECC study the effects of special protection systems, remedial action schemes and safety nets, such as the one that disconnected San Diego from the high voltage lines south of the San Onofre Nuclear Generating Station, to understand how they affect reliability and to ensure that they do not have unintended or undesirable effects; and
- System operators plan and account for phase angle differences in order to be able to re-energize transmission lines following outages.

## DOE Releases Cybersecurity Risk Management Process (RMP) Guideline

*Public-Private Sector Collaboration Produces Guidance to Help Electric Utilities Better Understand and Assess Cybersecurity Risk*

The Department of Energy's (DOE) Office of Electricity Delivery and Energy Reliability, in collaboration with the National Institute of Standards and Technology (NIST) and the North American Electric Reliability Corporation (NERC), today released guidance to help utilities better understand their cybersecurity risks, assess severity, and allocate resources more efficiently to manage those risks. The Electricity Subsector Cybersecurity Risk Management Process (RMP) guideline, which provides a flexible approach to managing cybersecurity risks across all levels of the organization, was developed by a public-private sector team that was led by the Office of Electricity Delivery and Energy Reliability and included representatives from across the industry.

"Addressing cybersecurity is critical to enhancing the security and reliability of the nation's electric grid and must be done in a cost-effective manner," said Patricia Hoffman, Assistant Secretary for the Office of Electricity Delivery and Energy Reliability. "The Department of Energy has been working closely with the Department of Homeland Security, other government agencies, and industry for years to reduce the risk of energy disruptions due to cyber attack. The RMP guideline provides utilities with consistent, adaptable solutions that help them manage their cybersecurity risks more effectively."

Feedback provided by industry, vendors, and other electricity subsector stakeholders during two comment periods was invaluable in refining the final RMP guideline. The guideline is now available for downloading.

The electricity subsector increasingly relies on digital technology to reduce costs, increase efficiency, and

maintain reliability during the generation, transmission, and distribution of electric power. Managing cybersecurity risk is critical to the success of organizations in achieving their strategic goals and objectives, including reliability, resiliency, security, and safety. DOE has a long history of working closely and steadily with Federal partners, including the Department of Homeland Security, on cybersecurity on the North American electric grid. All of these activities align with the *Roadmap to Achieve Energy Delivery Systems Cybersecurity,* which was released in September 2011 by DOE and outlines a strategic framework over the next decade to design, install, operate, and maintain a resilient energy delivery system capable of surviving a cyber incident while sustaining critical functions. The Electricity Subsector Cybersecurity Risk Management Maturity Initiative, which will tie together elements from existing cybersecurity efforts to develop a common model that allows electric utilities and grid operators to assess their cybersecurity capabilities and assist in prioritizing their investments, is the next logical step in a continued effort by public and private stakeholders to identify steps to improve the cybersecurity of the electric grid.

The Electricity Subsector Cybersecurity Capabilities Maturity Model is expected to be available to the electricity subsector this summer.

To learn more about national efforts to ensure a reliable, secure, and resilient electric grid, visit the Office of Electricity Delivery and Energy Reliability.

## Board Adopts 5 Standards; Highlights ERO Strategic Milestones

The North American Electric Reliability Corporation's (NERC) quarterly Board of Trustees meeting took place on May 9 in Arlington, Va. Board Chair John Q. Anderson opened the meeting, welcoming FERC Commissioners John Norris and Cheryl LaFleur, and U.S. and Canadian industry participants.

NERC President and Chief Executive Officer Gerry Cauley commended the cooperation and collaboration between NERC and the Federal Energy Regulatory Commission (FERC) on the September 2011 Southwest outage inquiry report. The thoroughness and detail of the report lay important groundwork for how the industry can better ensure the reliability of the bulk power system.

"The joint outage report allows us to look at events from a broader perspective and see commonalities across the system, not just in one interconnection," Cauley said. "We need to look at underlying issues *before* events happen to make sure we have adequate programs in place. This introspection can be accomplished through a risk-based approach of testing and evaluating."

Cauley also highlighted three strategic milestones achieved to date in 2012 by the electric reliability organization (ERO):

- **Standards Process Input Group.** The high-level Member Representatives Committee working group was formed to provide policy input and recommendations on key issues in the standards area, including quality of process and product, timeliness, efficiency and effectiveness, and significance of American National Standards Institute requirements.
- **State of Reliability report.** This report follows the 2011 foundational report that reviews and assesses the state of reliability based on trends identified through data combined with root cause analysis of events. The key findings serve as technical input to NERC's Reliability Standards and project prioritization, compliance process improvements, event analysis, reliability assessment and critical infrastructure protection.
- **Severe Impact Resilience and Cyber Attack Task Force reports.** These two reports are the final of four task force reports that address high-impact, low-frequency events. The reports provide guidance to industry on enhancing and protecting the resilience of the bulk power system against debilitating grid

events. Previous task force reports addressed geomagnetic disturbances and spare equipment.

During this meeting, the board adopted five reliability standards: FAC-003-3 – Transmission Vegetation Management Program; PRC-005-1.1b – Transmission and Generation Protection System Maintenance and Testing; TOP-001-2 – Transmission Operations; TOP-002-3 – Operations Planning; and TOP—003-2 – Operational Reliability Data Real-Time Operations. One interpretation, 2010-05 of CIP-002-1 for Duke Energy, also was adopted.

FERC Commissioners Cheryl LaFleur, John Norris and Philip Moeller attended the Member Representatives Committee meeting on May 8. The next NERC Board of Trustees meeting is scheduled for August 16 in Quebec City, Canada.

## Compliance

### Compliance Analysis Report Completed

NERC worked with the Regional Entities, the Compliance and Certification Committee and the Critical Infrastructure Protection Committee to provide meaningful comments for May CIP-005 Compliance Analysis Report on Electronic Perimeter Security. To date, this is the most comprehensive report and offers many suggestions on compliance for registered entities, as well as the usual violation statistics and violation description examples.

The expectation with the CIP-005 standard is that critical asset identification drives the process. The CIP-005 standard also suggests that critical asset and critical cyber asset identification process feeds into the Electronic Security Perimeter (ESP) identification, implementation, monitoring and vulnerability processes. The registered entity may consider the following order of steps for establishing compliance to CIP-005:

- Identify Critical Assets
- Identify Critical Cyber Assets
- Design Electronic Security Perimeter
- Identify everything within the ESP
- Identify ESP Access Points
- Identify cyber assets that perform access control and monitoring of the ESP
- Perform annual cyber vulnerability assessment of electronic access points to the ESP
- Document results of the identification and implementation process

There currently are 369 possible violations all-time, with 249 of them occurring in the last 12 months. The 249 possible violations rank second behind CIP-007. It is encouraging to see that 66 percent of CIP-005 violations were self-identified.

### Focus Groups Assist on Entity Assessment Template Development

NERC Compliance hosted eight focus groups during April to gather feedback from industry regarding the performance metrics and technical facts to consider in an Entity Assessment template.

The morning and afternoon sessions were made up of the following entity types: Balancing Authority/Regional Coordinator, Generator Owner/Generator Operator, Transmission Owner/Transmission Operator, and Small Entities.

The Entity Assessment template is in development, but results from the focus groups are posted and sent to the Compliance and Certification Committee working group for assessment. The Entity Assessment template early is expected to be completed this summer.

### Compliance Application Notice Update

CAN-0038, which addresses how many hours constitute five days of training, was removed from development because PER-005-1 R3 provides clear guidance on the topic.

The following CANs are posted for industry comment: CAN-0019 CIP-007 R3.2: Implementation of Software Security Patches of Upgrades; and CAN-0023 CIP-005

R3, CIP-006 R6 Logging System Failures. Comments are due June 4. In addition, the prioritization of potential CAN issues was updated based on feedback from NERC committees and registered entities. To view the CAN status and priority list, click here.

### RSAW Information Uploaded to Website

Changes, based on industry comment, were made to two Reliability Standard Audit Worksheets -- PER-005-1 and COM-002-2a. Most notably, the information on internal controls and administrative issues was removed from the RSAW. Separate documents for internal controls and administrative issues will be posted for comment soon.

Both RSAWs will be sent to the Regions for review, and NERC Compliance expects to post the final RSAWs in June.

**Note:** Current RSAWs for use, DRAFT RSAWs for Industry Review, RSAW Tools and Industry Feedback are located at this link. Please use the RSAW Feedback Form located in the "Tools" section when providing feedback on draft RSAWs.

### Rules of Procedure Reminder

Section 501.1.3.7 of NERC's Rules of Procedure requires registered entities to notify NERC and its corresponding Regional Entity of any changes in ownership, corporate structure or similar matters that affect the entity's responsibilities with respect to the reliability standards.

Failure to notify NERC does not relieve the entity from responsibility to comply with the NERC Reliability Standards or be liable for any penalties or sanctions associated with failing to comply with such standards.

## Critical Infrastructure

### NERC Releases Two Reports Focused on High-Impact, Low-Frequency Risks

The North American Electric Reliability Corporation (NERC) released two technical reports recently as part of its Critical Infrastructure Strategic Roadmap to address high-impact, low-frequency events that have the potential to affect the reliability of the North American bulk power system.

The two reports address cyber attack incidents and severe impact resilience, and provide guidance to the industry on enhancing and protecting the grid against debilitating events.

"While NERC and the industry have been actively addressing critical infrastructure issues for many years, these reports help address particularly severe events with the potential to impact large portions of the grid and disrupt service to customers for an extended period of time," said Gerry Cauley, president and chief executive officer at NERC. "Increasing our understanding of these events allows us to put necessary and appropriate solutions in place that better ensure the reliability of the bulk power system.

The *Cyber Attack Task Force* report provides guidance to prevent, deter, detect and respond to a coordinated cyber attack. The report describes aspects of cybersecurity that could be challenged through a sophisticated cyber attack and provides options to protect the assets, systems and networks critical to the reliable operation of the bulk power system.

The *Severe Impact Resilience: Considerations and Recommendations* report provides guidance to asset owners and operators on enhancing the resilience of the bulk power system to potentially catastrophic events, such as coordinated physical or cyber attacks or a severe geomagnetic disturbance. The report describes the concept of a "new normal," where the bulk power system is restored and operated at a reduced state of reliability for months or possibly years.

A complement of reports was developed in response to recommendations from a June 2010 joint NERC and Department of Energy report - *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System*. The HILF report focused on a class of rare risks to the bulk power system that were

identified as part of NERC and the Electricity Sub-Sector Coordinating Council (ESCC) roadmap for addressing these types of events. The HILF report found that the best approach to these events would be through an organized combination of industry-led task forces and NERC staff initiatives.

The ESCC, which is chaired by Cauley, is made up of electricity industry chief executive officers from across North America. The ESCC fosters sector-wide initiatives to improve the reliability and resilience of the electricity sector, including physical and cybersecurity infrastructure.

Other task force reports developed in response to the roadmap include the *Spare Equipment Database* report and the *2012 Special Reliability Assessment: Effects of Geomagnetic Disturbances on the Bulk Power System* report.

### CIP Sufficiency Review Program Refresh

The NERC Sufficiency Review Program, which began in 2010, has conducted 13 reviews of Entity Risk-based Assessment Methodologies (RBAMs) in support of NERC Standard CIP-002. Since Version 4 of NERC's cybersecurity standards removes the RBAM requirement, the Sufficiency Review Program was refreshed to include issues pertaining to the transition from a Version 3 "RBAM approach" to a Version 4 "bright-line approach."

Version 5 of NERC's cybersecurity standards is currently being developed. To address this, the 2012 Sufficiency Review Program was renamed CIP V4/V5 Outreach Session. NERC plans to conduct 10 sessions in 2012.

The CIP V4/V5 Outreach Sessions serve as an educational opportunity and are not compliance related. The sessions focus on the "sufficiency" of industry implementation of CIP standards and addresses how entities transition from Version 3 to Version 4 more effectively. NERC and Regional CIP staff will reference guidance documents and industry best practices to help determine RBAM thoroughness and walk entities through future Version 4 requirements.

A key component of the sessions will be the opportunity to engage in an open dialogue with NERC and the Regions on security- or compliance-related topics. For more information or to schedule a CIP V4/V5 Outreach Session, please contact Brian Harrell.

## Reliability Assessment and Performance Analysis

### Summer Reserve Margins Predicted to be Adequate in Most Regions; ERCOT Below Reserve Capacity Targets

Most of North America has sufficient resources available to meet summer peak demands, the North American Electric Reliability Corporation's (NERC) *2012 Summer Reliability Assessment* finds. However, planning reserve margins in the Electric Reliability Council of Texas (ERCOT) assessment area are projected to be below the NERC Reference Margin Level, the threshold by which resource adequacy is measured. In California, reserves are projected to be tight, but manageable, through the summer months.

"Reduced planning reserves in certain areas will challenge operations this summer," said Mark Lauby, vice president and director of Reliability Assessment and Performance Analysis. "NERC has reviewed the operating procedures and preparations in the assessment areas, and in most areas they appear to be sufficient to meet these challenges."

Since summer 2011, capacity resources have grown across North America by approximately 12,310 megawatts, most notably within the SERC Reliability Corporation and the Northeast Power Coordinating Council areas. Compared to the 2011 projections, NERC-wide total peak demand forecast is 3,700 MW lower. The largest increase in peak demand is expected in ERCOT, where a 1.7 percent increase is projected.

"With continued growth in peak demand and only a small amount of new generation coming online,

resource adequacy levels in ERCOT have fallen below targets," said John Moura, manager of Reliability Assessment at NERC. "If ERCOT experiences stressed system conditions or record-breaking electricity demand due to extreme and prolonged high temperatures, system operators will most likely rely on demand response and emergency operating procedures, which may include initiating rotating outages to maintain the reliability of the interconnection."

Key highlights for summer 2012:

- Extreme weather could lead to stress conditions in Southern California and Texas; planned interruptions of firm load may be necessary
- The unanticipated outage of San Onofre Nuclear Generating Station reduces available summer capacity; transmission ties critical to the reliability of Southern California
- Enhanced operations and planning approaches instituted in response to 2011 Southwest outage
- Variable generation continues to increase in most assessment areas
- Demand-side management key to maintaining reliability this summer
- Extreme weather events will challenge bulk power system operators
- Lower global liquefied natural gas supply may impact generation in New England; ISO to implement proactive measures

Download the *2012 Summer Reliability Assessment* by clicking here.

## State of Reliability Report Offers Historical Reference on Bulk Power System Trends

The North American Electric Reliability Corporation (NERC) released the *2012 State of Reliability* report that reviews and assesses the state of reliability based on trends identified through data combined with root cause analysis of events. This report is follow-on to the 2011 foundational report and represents NERC's integrated view of ongoing bulk power system reliability trends.

"This report is a realization of ongoing efforts to synthesize data from multiple databases and combine them with analyses of events seen each year to allow NERC to produce an annual, independent assessment on reliability performance," said Gerry Cauley, president and chief executive officer of NERC. "The report is a major step forward in characterizing and identifying risks in order to develop coordinated, multifunctional solutions."

Key findings identified in the report include:

- Reliability of the bulk power system remains adequate, with little change in trends between 2008 to 2011.
- Frequency response is stable with no deterioration.
- Protection system misoperations are a significant reliability issue.
- Equipment failure warrants further analysis.
- Resource mix changes necessitate new metrics.
- More data and research is needed.

"This information provides a historical reference for the industry on bulk power system reliability," said Jessica Bian, director of Performance Analysis at NERC. "The report's findings and recommendations serve as technical input to NERC's efforts to control reliability risks, standards development and compliance process improvement."
This report assesses 18 metrics that address the characteristics of an adequate level of reliability, industry-wide automatic transmission and generating outage rates from 2008 to 2011. Analysis from the frequency response, 2011 demand response availability, event analysis trends, and post summer operations also are highlighted.

Click here to download the *2012 State of Reliability* report.

## Spare Equipment Database in Operation

The North American Electric Reliability Corporation's (NERC) online spare equipment database is now operational. The inventory of spare equipment will be a helpful industry resource should a high-impact, low-frequency event result in damaged equipment.

Providing information to the database is voluntary and meant to complement existing transformer sharing and mutual assistance agreements. The database is populated and managed by participating organizations bound by confidentiality agreements. NERC's initial focus is on high-voltage transmission and generator step-up transformers, which are vital for operation of the integrated bulk power system.

The spare equipment database builds on industry's existing extraordinary ability to address high-impact, low-frequency events," said Mark Lauby, vice president and director of Reliability Assessment and Performance Analysis. "Industry's participation demonstrates its continued commitment to bulk power system reliability."

The database was developed based on recommendations from the *Spare Equipment Database* report, which was formed in response to direction from NERC's board upon acceptance of the Electricity Sub-Sector Coordinating Council's *Critical Infrastructure Strategic Roadmap*. The joint NERC and Department of Energy report – *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System* – released in June 2010 initiated the roadmap development.
Stakeholders must complete the registration process in order to be credentialed and gain access to the database. For more information on the program and database access, contact Andrew Slone.

## New Technical Standard for Synchrophasors Adopted by IEC

The North American Electric Reliability Corporation (NERC) and the North American SynchroPhasor Initiative (NASPI) are pleased with the International Electrotechnical Commission's (IEC's) adoption of a technical standard that establishes improved synchrophasor data communication. The approval of technical interoperability standards is an important milestone marking the maturity synchrophasor technology and systems. Further, industry consensus allows manufacturers to standardize their offerings.

"Adoption of this IEC standard supports the integration of synchrophasor technology into day-to-day grid operations," said Mark Lauby, vice president and director of Reliability Assessment and Performance Analysis at NERC. "We appreciate the hard work of volunteer experts from IEC, the Institute of Electrical and Electronics Engineers (IEEE), NASPI and the federal government, each of whom contributed to the development of this technical standard."

IEC 61850-90-5 is one of several key technical interoperability standards adopted to advance smart grid technology. The new standard addresses delivery of high-speed data collected by synchronized phasor measurement devices over wide-area communications networks. Further, they incorporate data latency requirements for Wide-Area Monitoring Protection and Control applications and assure cybersecurity protection for this data.

The Department of Energy is working with the National Institute of Standards and Technology (NIST) to accelerate the development of key smart grid interoperability standards, including IEC 61850-90-5, with funding and coordination. NASPI's Performance and Standards Task Team (PSTT), working with NIST, continues to develop standards and guidelines for phasor measurement units, phasor data concentrators, GPS time-stamping of phasor data, and related synchrophasor technology elements.

More than 65 transmission owners and operators across North America have deployed synchrophasor systems to monitor transmission grid conditions and improve grid operations. Most of these phasor projects have received financial and technical support from the Department of Energy under the Smart Grid Investment Grants funded by the 2009 American Reinvestment and Recovery Act.

The North American SynchroPhasor Initiative (NASPI) is an international collaborative effort between NERC, the Department of Energy and the North American electric industry focused on accelerating the use of synchrophasor technology to enhance grid reliability. For more information, visit NASPI website.

### New Web-Based Data System Helps Mandatory Collection Efforts

The North American Electric Reliability Corporation (NERC) launched a new web-based data collection system that collects information for measuring and monitoring the contributions of electric power plants to the reliability of the bulk power system.

NERC has collected electric generating unit operational data from the industry using the Generating Availability Data System (GADS) since 1982. To increase the value of the information provided on power plant reliability, in August 2011 NERC's Board of Trustees broadened GADS participation to all North American conventional power plants.

"Statistics from GADS have been an important industry source for information on power plant performance and resource planning for more than three decades," said Mark Lauby, vice president and director of Reliability Assessment and Performance Analysis. "Expanding GADS data collection to all power plants connected to the bulk electric system in North America supports the evolution to an integrated view of overall system and equipment reliability."
The new web-based system will facilitate the data collection process and provide NERC access to vital information needed to evaluate electric generation of the bulk power system in North America. Units with a nameplate rating of 50 MW and larger will begin reporting their information beginning January 1, 2012. For units 20 MW and larger, data collection will begin in 2013.

For more information on GADS, visit the website by clicking here. Visit the NERC website at www.nerc.com.

## Standards

### Phase 2 of BES Definition Project

The Standards Committee approved a supplemental Standard Authorization Request for the second phase of the bulk electric system definition project on April 12, 2012.

The Project 2010-17 BES definition drafting team filed the first phase of its work addressing FERC Order 743 (subsequently clarified in Order 743-A) with FERC in January 2012. The orders directed NERC to revise the definition of BES to encompass all elements and facilities necessary for the reliable operation and planning of the interconnected bulk power system, and included specific directives for the retention of the radial exclusion, the elimination of regional discretion which exists in the current definition, and the development of a process for identifying any elements or facilities that should be excluded from the BES.

During the Phase 1 posting of the draft BES definition for industry comment, the drafting team received many suggestions that fell outside the narrow scope of the regulatory directives in FERC Orders No. 743 and 743-A, including the following areas of concern:

- 100kV bright-line voltage threshold
- Thresholds for generation and reactive resources
- Points of demarcation between transmission, generation and distribution
- Power flow out of local networks
- Relationship between the BES definition and ERO Statement of Compliance Registry Criteria

The drafting team realized that technical justifications would be required for any threshold values, requiring additional technical expertise, so it reached out to the Operating Committee and Planning Committee for assistance. The Planning Committee is taking the lead in the activities and the Operating Committee will

follow the developments through a liaison with the Planning Committee's Executive Committee.

The Executive Committee will handle the bright-line voltage criteria study; the Reliability Assessment Subcommittee will deal with the generation threshold study; and the Systems Analysis and Modeling Subcommittee will work on the reactive power threshold and the local network power flow issue. The results of all of this work are scheduled to be provided by December 20, 2012.

Meanwhile, the drafting team is working on the relationship between BES definition and ERO Statement of Compliance Registry Criteria and clarification of terminology utilized in the definition. The team also is working on a guidance document that will incorporate text and diagrams to clarify the Phase 1 definition and show demarcation points; this will be posted for industry comment following a response from FERC on the current filing.

Phase 2 is expected to be completed in the fourth quarter of 2013.

## Frequency Response Technical Conferences

On May 22 and May 24, NERC staff and the Project 2007-12 Frequency Response standard drafting team hosted Frequency Response Technical Conferences in Arlington, Va., and Denver. About 100 stakeholders participated in person, with an additional 100 participating via webinar during the Denver event.

FERC staff from the Office of Electric Reliability attended both conferences and expressed their views on the importance of addressing frequency response.

Morning sessions at the conferences reviewed the purpose of frequency response – an Interconnection's ability to stabilize frequency to 60 Hz immediately following the sudden loss of generation or load, a critical component in the reliable operation of the Bulk Electric System – and the need for a standard addressing the concept.

Afternoon sessions were dedicated to panel discussions and provided participants the opportunity to ask questions about critical issues.

In a May 4, 2012, FERC order, NERC and the drafting team were granted a one-year extension to submit a revised frequency response standard, BAL-003-1—Frequency Response and Frequency Bias Setting. During the conference, the drafting team reviewed the current draft of the standard, which was developed in response to comments received during a comment and ballot period that ended in December 2011. The second draft of the standard is not substantially different from current practice, but it adds further data collection consistency, so the standard and frequency response can be improved over time.

The drafting team will consider all issues raised and discussed during these conferences as it works toward completion and posting of the second draft of BAL-003-1. The team will also coordinate with the Project 2007-09 Generator Verification and Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves drafting teams to ensure all NERC standards related to frequency response are appropriately aligned.

Comments on the technical conference and its contents should be submitted here.

## New Standards Email Addresses

All major NERC standards communication will now be issued from the NERC-StandardsAnnouncements-DoNotReply@nerc.net address, rather than from individual NERC staff members' email addresses. This change will allow stakeholders to more easily sort and search for announcements issued from NERC's standards department.

While the email address will be a "do not reply" address, all announcements will include information about whom to contact with questions, along with a hyperlink that pre-populates an email to the appropriate NERC staff member.

### Standard Drafting Team Vacancies

Any industry stakeholder meeting the indicated qualifications for one of the following three vacant appointments may submit a self-nomination form to sarcomm@nerc.com. Further instructions can be found on the Drafting Team Vacancies page on NERC's website.

**Project 2007-02 Operating Personnel Communication**
Seeking an individual with Transmission Operating Center, Reliability Coordinator, or Balancing Authority experience from SERC or SPP. Candidates should have experience developing verbal or written communication protocols for real-time operating personnel or managing real-time Bulk Electric System operations, or be a member of the Reliability Coordinator Working Group.

**Project 2007-06 System Protection Coordination**
Seeking an individual from a Canadian entity with experience in coordination of protection systems (new installations and revisions).

**Project 2007-12 Frequency Response**
Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

**Project 2010-13.2 Generator Relay Loadability**
Seeking an individual with experience in generator protection systems from the FRCC or MRO region and either the cooperative or merchant electricity generator sector.
Please contact Andy Rodriquez with questions regarding the vacancies.

## Training

### New Contact Information for System Operator Training and Education

NERC's System Operator Certification and Continuing Education (SOCCE) programs implemented new contact information to better serve system operators and continuing education providers.

For questions or support on the SOCCE database, transcripts or course information, call **404-446-9759** or email NERC.System.Operator.Certification@nerc.net or NERC.Continuing.Education@nerc.net. These email addresses can also be found on the NERC website under Q&A Email Addresses.

## Filings

### NERC Filings to FERC

(click on the link for full filing)

*May 3, 2012*
**Request for Information of NERC on the Notice Inviting Comments on the PNNL Report Concerning the Applicability of the Gallet Equation to the Vegetation Clearances of NERC Transmission Vegetation Management Reliability Standard FAC-003-2**
NERC submits a request for information on the Notice Inviting Comments regarding related documents. *Docket No. RM12-4-000*

*May 4, 2012*
**Petition for Approval of Proposed NPCC Regional Reliability Standard PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding**
NERC submits a Petition for Approval of Proposed NPCC Regional Reliability Standard PRC-006-NPCC-1— Automatic Underfrequency Load Shedding. *Docket No. RM_-_---*

*May 7, 2012*
**Petition for Approval of Revisions to NERC ROP**
NERC submits a filing including revisions to Sections 300, 400, 600, 1000, 1400 and 1700 and to Appendices 2, 4B, 4C, and 5B, and the deletion of Appendices 3C and 6 to the NERC Rules of Procedure. The proposed revisions are the result of a wide-ranging, comprehensive review of the ROP that was conducted to identify improvements to the underlying processes reflected in the ROP based on the experience to date of NERC and the Regional Entities, to further implement actions identified in 2009 in NERC's Three-Year ERO Performance Assessment Report, to eliminate internal inconsistencies, and to make other improvements and clarifications identified by the review teams. *Docket No. RR12-8-000*

*May 14, 2012*
**NERC's CEI Filing Informational Report**
NERC submits this filing in compliance with the March 15 Order where FERC accepted NERC's petition requesting approval of its proposal to make informational filings in a Find, Fix, Track and Report ("FFT") spreadsheet format in connection with the Compliance Enforcement Initiative ("CEI"). The Report describes the experience from September 2011 to March 2012 as well as the

feedback received with regard to the initiative. *Docket No. RC11-6-000*

**NERC Compliance Filing (Compliance Enforcement Initiative)**
NERC submits this filing in compliance with the March 15 Order where FERC accepted NERC's petition requesting approval of its proposal to make informational filings in a Find, Fix, Track and Report ("FFT") spreadsheet format in connection with the Compliance Enforcement Initiative ("CEI"). *Docket No. RC11-6-000*

*May 21, 2012*
**NERC's Request for Rehearing and Clarification**
NERC submits a Request for Rehearing and Clarification in connection with the April 19 Order which granted an appeal filed by the United States Department of Energy, Portsmouth/Paducah Project Office (DOE PPPO) and found that it should not be registered as a load-serving entity (LSE) under the NERC Statement of Compliance Registry Criteria. *Docket No. RC08-5-001*

**Request of NERC for Reconsideration, or in the Alternative, Rehearing of Order Remanding the Transmission Planning Reliability Standards**
NERC submits a Request for Reconsideration, or in the Alternative, Rehearing of Order Remanding the Transmission Planning Reliability Standards. *Docket No. RM11-18-000*

**Comments of NERC Following the Technical Conference on Geomagnetic Disturbances to the Bulk-Power System**
NERC files comments following the FERC Technical Conference held on April 30, 2012 regarding Geomagnetic Disturbances to the Bulk Power System. *Docket No. AD12-13-000*

*May 24, 2012*
**Petition for Approval of Interpretation to CIP-006 - Physical Security of Critical Cyber Assets**
NERC submits a Petition for Approval of Interpretation to Reliability Standard CIP-006 – Cyber Security — Physical Security of Critical Cyber Assets. This interpretation will be known as either CIP-006-3d or CIP-006-4d, whichever version of the standard is in effect at the time of FERC approval. *Docket No. RM_-___-___*

*May 25, 2012*
**Response of NERC to FERC Office of Reliability's May 4, 2012 Data Request regarding FAC-003-2**
NERC files its response to the FERC Office of Electric Reliability's May 4, 2012 Data Request regarding FAC-003-2. Do*cket No. RM12-4-000*

*May 30, 2012*
**NERC 2011 True-Up - Report of Comparisons of Budgeted to Actual Costs for 2011 for NERC and the Regional Entities**
NERC submits a filing to provide comparisons of actual to budgeted costs for the year 2011 for NERC and the eight Regional Entities. *Docket No. RR12-__-000*

*May 31, 2012*
**First Quarter 2012 Compliance Filing of NERC in Response to Paragraph 629 of Order No. 693**
NERC submits the First Quarter 2012 Compliance Filing of the North American Electric Reliability Corporation in Response to Paragraph 629 of Order No. 693. Order No. 693 requires that NERC 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 contains the referenced material pertaining to the first quarter of 2012. *Docket No. RM06-16-000*

## NERC Filings in Canada, click here
(click on the link above for full filing)

*May 3, 2012*
Notice of Errata to FAC-003-2
NERC submits a notice of filing regarding the errata to the Proposed Reliability Standard FAC-003-2—Transmission Vegetation Management correcting a typo in the Compliance section of the standard.

*May 11, 2012*
Notice of Filing of Proposed NPCC Regional Reliability Standard PRC-006-NPCC-1
NERC submits a notice of filing regarding the Proposed NPCC Regional Reliability Standard PRC-006-NPCC-1— Automatic Underfrequency Load Shedding

*May 18, 2012*
Report Plan and Timetable for Remand of TPL-002-2b
NERC submits a plan and timetable for modification or development of the Reliability Standard TPL-002-2b.

*May 22, 2012*
Notice of Filing of Revisions to the Rules of Procedure
NERC submits a notice of filing including revisions to Sections 300, 400, 600, 1000, 1400 and 1700 and to Appendices 2, 4B, 4C, and 5B, and the deletion of Appendices 3C and 6 to the NERC Rules of Procedure. The proposed revisions are the result of a wide-ranging, comprehensive review of the ROP that was conducted to identify improvements to the underlying processes reflected in the ROP based on the experience to date of NERC and the Regional Entities, to further implement actions identified in 2009 in NERC's Three-Year ERO Performance Assessment Report, to eliminate internal inconsistencies, and to make other improvements and clarifications identified by the review teams.

## Careers at NERC

**Manager of Bulk Power System Awareness**
Location: Atlanta
Details

**Compliance Enforcement Engineering Specialist**
Location: Washington, DC
Details

**Manager of (NOP) Notice of Penalty Development**
Location: Washington, DC
Details

**Compliance Enforcement Analyst**
Location: Washington, DC
Details

**Senior Compliance Enforcement Analyst**
Location: Washington, DC
Details

**CIP Security Specialist**
Location: Washington, DC
Details

**Senior Reliability Engineer (Relay)**
Location: Atlanta
Details

**Senior Reliability Engineer (EMS)**
Location: Atlanta
Details

**Attorney**
Location: Washington, DC
Details

**Engineer of Reliability Initiatives and System Analysis**
Location: Atlanta
Details

**Standards Adviser**
Location: Atlanta
Details

**Auditor Training Specialist**
Location: Atlanta
Details

**Standards Development Adviser**
Location: Atlanta
Details

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# NERC News

June 2012

## Compliance

**Update on the Entity Assessment Template**

**Two CANS Revised, Posted; Comment Deadline for Two CANS Extended**

**New RSAW Categories**

**New Compliance Email Address**

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## Critical Infrastructure Protection

**Make Plans to Attend NERC's Second Grid Security Conference in October**

## Reliability Risk Management

**Make Plans to Attend Cause Analysis and Data Workshop in Atlanta in July**

## Standards

**Standard Processes Manual Revisions Posted for Industry Comment**

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**Standard Drafting Team Vacancies**

## NERC Filings

**Documents Filed with FERC and/or Canada during the Month**

## Careers

**NERC Seeks Talented Professionals**

## Compliance

### Update on the Entity Assessment Template

NERC continues to make progress on the Entity Assessment (or Entity Impact Evaluation) template, which is a working name for the activity. A final name will be determined during the remainder of the process. The Certification and Compliance Committee working group has submitted their final draft of the template for the committee's endorsement. The template will be used as a base document with input from the Regional Entities and focus groups incorporated. The target is to have the consolidated template posted by late July for a six-week industry comment period.

### Two CANS Revised, Posted; Comment Deadline for Two CANS Extended

CAN-0011 PRC-005 R2 Interval Start Date for New Equipment and CAN-0012 Completion of Periodic Activity Requirements during Implementation Plan were revised to align with the compliance approach issued in the High-Level Review of CAN-0008 Basis for First Maintenance and Testing Date. The review provides additional flexibility in what would be considered acceptable evidence for compliance activities conducted prior to the enforceable date of a standard or requirement.

The industry comment period for Draft CAN-0033 PRC-023 Transmission Relay Loadability Criteria Selection and CAN-0044 TOP-001 Operating Emergencies and Emergency Conditions was extended to July 9. Please submit the CAN Comment Form to cancomments@nerc.net to comment.

### New RSAW Categories

NERC is categorizing Reliability Standard Audit Worksheets into three "avenues" to conduct updates.

- The first avenue is RSAWs that will be developed in parallel with the development of a standard. This is a future endeavor and several projects are being considered for the pilot.
- The second avenue is RSAWs that are associated with a standard that has had a change, such as an interpretation or a version update. This avenue provides for the initial drafting to be conducted by either the standards drafting team, a NERC committee, or another group with expertise. The RSAWs are provided to all NERC committees for comment and are then posted for industry comment. The last step is review by the Regional Entities and NERC.
- The last avenue is RSAWs associated with currently enforceable standards. These RSAWs will continue to be updated with the current process.

### New Compliance Email Address

All major NERC Compliance communication will be issued from a new email address, NERC Compliance Operations Announcements (Do Not Reply), rather than from individual NERC staff members' email addresses. This change will allow stakeholders to more easily sort and search for announcements issued from NERC's compliance department.

### Reminder: Submit Entity Updates

Registered Entities are required by the NERC Rules of Procedure to submit updates to registration and/or certification information as necessary to their respective Regional Entities and/or NERC. The decision to certify changes to an already operating and certified Registered Entity (RC, BA and/or TOP) is a collaborative decision between the affected Regional Entity(s) and NERC. Appendix 5A describes "Items to consider" in making this decision.

## Critical Infrastructure Protection

### Make Plans to Attend NERC's Second Grid Security Conference in October

The North American Electric Reliability Corporation (NERC) will host its second Grid Security Conference (GridSecCon) on October 16-18 in San Diego at the San Diego Marriott Del Mar.

The conference, GridSecCon 2012, will bring together industry and government security professionals to discuss grid security concerns, trends and best practices in security in the industry. Gerry Cauley, NERC's president and chief executive officer, will deliver the opening keynote address. Retired Admiral Thad Allen from Booz Allen Hamilton, former Coast Guard commandant, will provide insight into crisis response. Other presenters include Bill Bryan from Department of Energy; Mark Fabro, Lofty Perch; Tom Galloway, North American Transmission Forum; as well as other experts from the electricity and cybersecurity industries.

"GridSecCon 2012 will build on the success of last year's conference, which provided comprehensive education on cyber and physical security," said Brian Harrell, associate director of Critical Infrastructure Protection programs at NERC. "This second conference will provide a venue for sharing emerging security trends and industry lessons learned, as well as a networking event for the electricity industry."

Some topics to be discussed during the three-day conference include:

- Emerging industrial control system security issues.
- Social engineering and phishing attacks.
- NERC's Critical Infrastructure Protection Reliability Standards.
- Public/private partnerships.
- Electricity Sector-Information Sharing and Analysis Center.

Click here for agenda, registration and hotel information; or contact Brian Harrell.

## Reliability Risk Management

### Make Plans to Attend Cause Analysis and Data Workshop in Atlanta in July

The North American Electric Reliability Corporation (NERC) will host a workshop to promote reliability through the advanced application of cause analysis, cause coding, data analysis and risk control. The 2012 Cause Analysis and Data Workshop are planned for July 31-Aug 2 at the Westin Buckhead in Atlanta.

The first day will be a class on the principles of cause analysis (including a section on cause coding for trend analysis). Data workshop topics include sources, collection, and uses of data to support reliable operation of the bulk power system from a variety of experts from industry, academia and the federal sector. Gerry Cauley, NERC's president and chief executive officer, will deliver the workshop opening keynote address.

The goal of the event is to identify concepts that streamline data collection and analysis processes, while ensuring minimal impact on stakeholder time and resources. Key topics during the three-day event include:

- One-day class on cause analysis, which includes a section on cause coding.
- A panel discussion on the current sources and uses of data and future opportunities.
- Current and future trends in Generating Availability Data System (GADS), Transmission Availability Data System (TADS) and Event Analysis reporting.
- The value in data - risk cluster identification and risk control.

Agenda, registration and hotel information are available on the NERC calendar. Reservations are limited for the Cause Analysis class, which costs $150. The Data Workshop is free, but registration is required. Interested participants may also contact Sandy Shiflett (for the workshop) or Ben McMillan (for the Cause Analysis class).

## Standards

### Standard Processes Manual Revisions Posted for Industry Comment

Proposed revisions to the NERC Standard Processes Manual (SPM) to implement the Standard Process

Input Group's (SPIG) recommendations were posted on June 20 for a 30-day comment period through July 19. The revisions aim to improve the standard development process so the Electric Reliability Organization (ERO) is able to develop technically sound standards more efficiently and with better use of industry resources.

The SPIG was formed by NERC's Board of Trustees and the Member Representatives Committee in February 2012 to develop recommendations to improve the standards development process. Members gathered input from industry subject matter experts, including the Regions, the MRC, standard drafting team leaders, NERC staff, and other stakeholders. From this input five key recommendations were developed, which the board approved in May 2012. The recommendations can be found in the posted SPIG report. The Standards Committee was specifically charged with addressing Recommendations 1, 4 and 5:

1. **American National Standards Institute (ANSI):** NERC should continue to meet the minimum requirements of the ANSI process to preserve ANSI accreditation.
4. **Standards Product Issues:** The NERC board is encouraged to require 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 board 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 board 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.

To address the recommendations, the Standards Committee leveraged each of its subcommittees, the Process Subcommittee and the Communications and Planning Subcommittee to work in parallel to develop proposed revisions and conduct outreach to industry stakeholders to ensure interested stakeholders have an opportunity to provide their input. Sub-teams of the process subcommittee developed the following proposed changes, many of which are outlined in detail in the redlined SPM:

- **Section 2.0:** Elimination of VRFs/VSLs and incorporation of measures into RSAWs.
- **Section 3.0:** Revised drafting team composition to incorporate SPIG recommendation to include lawyers and compliance experts; incorporated SPIG recommendation that drafting teams participate in developing RSAWs and compliance elements.
- **Section 4.0:** Streamlined commenting and balloting process, including:
    - Provisions for providing summary responses to comments and the elimination of the obligation to respond in writing at every stage of the comment process
    - Elimination of negative votes without comments and negative votes with unrelated comments in the calculation of consensus; and
    - Provisions to allow for quality reviews to be conducted in parallel with standard development.
- **Section 7.0:** Incorporated guidance regarding the appropriate role and scope of Interpretations, to be consistent with guidance from the NERC board.
- **Section 13.0:** Revised to reduce the requirement for periodic review to be consistent with ANSI-minimum requirements.
- **Section 16.0 (new):** Incorporation of a waiver provision to allow for modifications to the standards development process for good cause.

Visit the project page to review the SPIG report, the revised SPM, a consolidated white paper with technical justification and background on the proposed changes, and other resource documents. For more information, contact Laura Hussey.

### State of Standards Webinar Agenda Posted

NERC will host its second annual State of Standards webinar to update industry stakeholders on standards development projects and other initiatives. The webinar will be from 1-5 p.m. (ET) July 26.

The agenda, which will be posted on NERC's calendar in early July, includes a review of active projects, a presentation on Standard Processes Manual revisions to address Standard Process Input Group recommendations, a risk forecast and consideration of its impact on standards development, and a status update on the Reliability Standards Development Plan. Stakeholders will have the opportunity to ask questions of NERC standards staff and Standards Committee Chair Allen Mosher at the end of the webinar. Register for the webinar here.

### Standard Drafting Team Vacancies

Any industry stakeholder meeting the indicated qualifications for one of the following three vacant appointments may submit a self-nomination form to sarcomm@nerc.com. More instructions can be found on the Drafting Team Vacancies page on NERC's website.

**Project 2007-02 Operating Personnel Communication**
Seeking an individual from SERC or SPP with Transmission Operating Center, Reliability Coordinator, or Balancing Authority experience. Candidates should have experience developing verbal or written communication protocols for real-time operating personnel or managing real-time Bulk Electric System operations, or be a member of the Reliability Coordinator Working Group.

**Project 2007-06 System Protection Coordination**
Seeking an individual from a Canadian entity with experience in coordination of protection systems (new installations and revisions).

**Project 2007-12 Frequency Response**
Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

**Project 2010-13.2 Generator Relay Loadability**
Seeking an individual with experience in generator protection systems from the MRO region and either the cooperative or merchant electricity generator sector.

Please contact Val Agnew with questions regarding the vacancies.

## Filings

### NERC Filings to FERC

(Click on the link for full filing)

*June 5, 2012*
**Petition of NERC for Approval of Errata Changes to Seven Reliability Standards**
NERC proposed errata changes and asks for approval of those changes going forward as BAL-005-0.2b: Automatic Generation Control; EOP-001-0.1b: Emergency Operations Planning; EOP-001-2.1b: Emergency Operations Planning; EOP-002-3.1: Capacity and Energy Emergencies; IRO-005-3.1a: Reliability Coordination – Current Day Operations; PER-001-0.2: Operating Personnel Responsibility and Authority; and TOP-002-2b: Normal Operations Planning. *Docket No. RD_-__-___*

*June 6, 2012*
**Motion of NERC to Correct the Record regarding Order No. 763**
NERC submits a limited motion to correct the record in regard to the Commission's Final Rule in this proceeding issued on May 7, 2012. *Docket No. RM11-20-000*

*June 7, 2012*
**Motion of NERC to Submit Answer to Comments on the Petition for Approval of Revision to the NERC Rules of Procedure**
NERC requests leave to submit this answer to the comments filed in response to NERC's Petition for Approval of Revisions to its Rules of Procedure filed on May 7, 2012. *Docket No. RR12-8-000*

*June 14, 2012*
**Withdrawal of Notice of Penalty**
NERC submits a Withdrawal of Full Notice of Penalty in connection with the May 30, 2012 submitted Full Notice of Penalty regarding Southern California Edison - Transmission & Distribution Business Unit. Docket No. *NP12-28-000*.

**Withdrawal of Full Notice of Penalty**
NERC submits a Withdrawal of Full Notice of Penalty in connection with the May 30, 2012 submitted Full Notice of Penalty regarding San Diego Gas & Electric. *Docket No. NP12-31-000.*

## NERC Filings in Canada, click here

(Click on the link above for full filing)

*June 15, 2012*
**Notice of Filing of an Interpretation to CIP-006-4**
NERC submits a notice of filing of an Interpretation to Reliability Standard CIP-006 – Cyber Security — Physical Security of Critical Cyber Assets.

**Notice of Filing of Errata Changes to Seven Reliability Standards**
NERC submits a notice of filing of proposed errata changes and asks for approval of those changes going forward as BAL-005-0.2b: Automatic Generation Control; EOP-001-0.1b: Emergency Operations Planning; EOP-001-2.1b: Emergency Operations Planning; EOP-002-3.1: Capacity and Energy Emergencies; IRO-005-3.1a: Reliability Coordination – Current Day Operations; PER-001-0.2: Operating Personnel Responsibility and Authority; and TOP-002-2b: Normal Operations Planning.

## Careers at NERC

**CIP Security Specialist**
Location: Washington, DC
Details

**CIP Compliance Auditor**
Location: Washington, DC
Details

**Compliance Program Education and Development Specialist**
Location: Atlanta
Details

**Senior Reliability Engineer (Relay)**
Location: Atlanta
Details

**Senior Reliability Engineer (EMS)**
Location: Atlanta
Details

**Attorney**
Location: Washington, DC
Details

**Senior Systems Administrator**
Location: Atlanta
Details

**Engineer of Reliability Risk Controls**
Location: Atlanta
Details

**Engineer of Reliability Initiatives and System Analysis**
Location: Atlanta
Details

**Standards Development Adviser**
Location: Atlanta
Details

**From:** Kimberly Mielcarek
**To:** Kimberly Mielcarek
**Subject:** NERC Announcements - 2011 Annual Report and May Newsletter Released
**Date:** Friday, June 01, 2012 11:48:28 AM

# Announcements

## NERC Releases 2011 Annual Report and May Newsletter

**Click for 2011 Annual Report**

**ATLANTA** -- The North American Electric Reliability Corporation's 2011 Annual Report highlights accomplishments from the past year. 2011 was a notable year with efforts focused on four pillars toward continued success as the electric reliability organization (ERO): reliability, assurance, learning and a risk-based approach to issues most important to the bulk power system. NERC continues to ensure the strength of the ERO's reliability programs by focusing on three major goals in 2012-2015 – standards and compliance, risks to reliability, and coordination and collaboration.

**Click for NERC News - May**

**WASHINGTON, DC** -- NERC News, NERC's monthly newsletter, is now available on the website or by clicking the link above. Read about NERC happenings from the month of May.

For more information or assistance, please contact Kimberly Mielcarek.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# 2011 Annual Report

May 2012

**RELIABILITY | ACCOUNTABILITY**






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# Message from the President and CEO



In terms of strengthened partnerships, increased accountability and focused attention on reliability, 2011 was a significant year for the North American Electric Reliability Corporation (NERC). In our fifth year as the electric reliability organization (ERO) and as an international partner of the ERO Enterprise, NERC aligned activities with eight regional entities, industry and government, and identified risks and prioritized solutions for the reliable performance of the bulk power system.

Some of the accomplishments in 2011 directly improved upon NERC's core functions. Working as the ERO Enterprise, NERC prioritized standards by focusing resources on high-priority projects, implemented a new model to balance compliance activities with enforcement discretion, and participated with the Federal Energy Regulatory Commission (FERC) in joint inquiries of significant electric outage events. Additionally, NERC dedicated efforts to the continued evaluation of emerging threats and vulnerabilities, examined power system impacts from extreme weather conditions, and participated in technical discussions and opportunities focused on secure reliability of the bulk power system. Another highlight of 2011 was the successful completion of a GridEx, which tested and validated current readiness in response to a cyber incident.

As NERC moves ahead, we look forward to sharing continued success with our stakeholders. In the near future, I anticipate the completion of the Adequate Level of Reliability definition, a new process for the development of reliability standards, and a shift in the way we enforce compliance activities. These initiatives are underway to increase clarity, streamline cumbersome, resource-intensive processes, and to improve upon the assurances that NERC provides to the public, industry and government.

As you read the enclosed results for 2011, I invite you to note the progress we are making in reliability and accountability to our vitally important responsibility of ensuring the reliability of the bulk power system of North America.

Gerry W. Cauley
President and CEO

# NERC Overview / Accomplishments of the ERO

In its fifth year as the ERO, NERC continued on its path of excellence by evolving and adapting programs and policies to better ensure the reliability of the bulk power system.

The ERO's key programs, which impact more than 1,900 bulk power system owners and operators, are based on four pillars of continued success:

- **Reliability:** to address events and identifiable risks, thereby improving the reliability of the bulk power system.
- **Assurance:** to provide assurance to the public, industry and government of the reliable performance of the bulk power system.
- **Learning:** to promote learning and continuous improvement of operations and adapt to lessons learned for improvement of bulk power system reliability.
- **Risk-based Approach:** to focus attention, resources and actions on issues most important to bulk power system reliability.

Throughout the year, the ERO enhanced its ability to analyze and interpret data, allowing NERC to identify specific risk areas and provide mitigation tools to industry. The collaboration between NERC, the Regions and industry was instrumental to the ERO accomplishing its 2011 goals.



## 2011 Initiatives

NERC identified high priority issues impacting reliability and focused ERO efforts on those program areas over the course of the year, including standards setting, compliance, and training and education. Some of the accomplishments include:

### Bulk Electric System Definition

The ERO and stakeholders worked together to develop a definition that addresses the FERC Order Nos. 743 and 743-A. The definition eliminates the basis for Regional Entity discretion and includes criteria for exempting facilities from application of the BES definition. As a result, Phase 1 of the Bulk Electric System definition was approved by the NERC Board of Trustees and filed with FERC and Canadian regulatory authorities in January 2012.

### Find, Fix and Track Compliance Enforcement Initiative

This initiative, which FERC endorsed in March 2012, allows issues to be handled more efficiently; focuses on issues posing a higher risk to reliability; streamlines administrative paperwork; and continues to encourage self-reporting and mitigation. The new initiative is a paradigm shift in how issues are processed, and reflects a risk-informed approach that recognizes all possible violations are not equal and should not be treated in the same manner. By focusing resources on violations that have a serious risk to the reliability of the bulk power system, NERC is able to better fulfill its mission to ensure the reliability of the bulk power system of North America.

### High-Impact, Low-Frequency Efforts

While there is a wide range of threats labeled "high impact, low frequency," the ERO's greatest concern is being prepared for possible events that could debilitate the bulk power system for extended periods, such as widespread, coordinated physical/cyber attacks or geomagnetic disturbances. To address these types of events, NERC produced the *Spare Equipment Database System* report (October 2011) and the *Effects of Geomagnetic Disturbances on the Bulk Power System* interim report (February 2012). Two more reports focused on cyber attack and severe impact resilience are expected in 2012.

### Human Performance

Field personnel play an important role in the maintenance and operation of the bulk power system. Risks can be introduced when field personnel operate equipment in a manner that reduces the redundancy of the bulk power system, sometimes creating single points of failure that would not typically exist. NERC established a Human Performance program in 2011 that strives to improve individual and organizational performance through processes and procedures that highlight accuracy, completeness and efficiency. The first human performance conference and workshop took place in March 2012 with more than 200 participants from industry, the Regions, academia and other industries.

### Gas-Electric Interdependency Assessment

Energy and environmental policies, along with energy markets, are driving unprecedented changes in the resource mix of the bulk power system. NERC released its *2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States* as a foundational review of gas and electric interdependencies that assesses existing and future challenges, identifies areas of vulnerability, and provides recommendations for enhancing reliability.



### Cybersecurity Efforts

NERC and the industry continued to establish enterprise, risk-based programs, policies and processes to prepare for, react to, and recover from cybersecurity vulnerabilities. NERC hosted its first Grid Security Conference (October 2011) that brought more than 260 industry and government security experts from the United States and Canada together to provide real tools and information that improve the security posture of companies. In November 2011, NERC hosted a grid security exercise (GridEx) that focused the efforts of more than 75 organizations on validating the readiness of the industry to respond to a cyber incident, strengthening the crisis response functions of utilities to provide input for internal security program improvements.

### Collaboration with FERC on Joint Inquiries

FERC and NERC collaborated on two joint inquiries in 2011: the Southwest extreme cold weather event in Texas and Arizona in February; and the Southwest outage in Arizona and California in September. By partnering in these efforts, the expertise of both FERC and NERC was leveraged, and the importance both organizations place on reliability to the grid was emphasized. These inquiries examined the policies and procedures of affected utilities and identified potential improvements and lessons learned.

The *Outages and Curtailments during the Southwest Weather Event of February 1-5, 2011* report was released in August. The *Arizona-Southern California Outages on September 8, 2011*, was released in May 2012.

## 2012 Strategic Goals

In 2012, NERC will continue to ensure the strength of the ERO's reliability programs by focusing on three major goals as part of the ERO Enterprise Strategic Plan 2012-2015:

- **Standards and compliance:** Through writing good standards, educating industry on effective compliance/risk control methods, and developing risk-based compliance monitoring.
- **Risks to reliability:** Through cause code and analysis tools that allow us to dive deeper into the cause of events by better identifying where things are breaking down.
- **Coordination and collaboration:** Through engagement with industry for a more integrated effort.

NERC, which is subject to oversight by the FERC, is committed to continuing its collaborative culture of learning in 2012 and beyond.



# Compliance

## Overview

The focus of NERC's compliance program is to improve the reliability of the bulk power system in North America by fairly and consistently enforcing compliance with NERC Reliability Standards. Specifically, the program is designed to ensure that the right practices are in place so that the likelihood and severity of any system disturbances are substantially reduced, while recognizing that no standards or enforcement process can fully prevent all such disturbances from occurring.

In the United States, NERC and the eight Regions charged with compliance enforcement monitor compliance via a number of methods, including regular and scheduled compliance audits, random spot checks and specific investigations as warranted by indications that a standard may have been violated.

NERC's overriding goals in compliance are to:

- Monitor registered entities for compliance with mandatory reliability standards in accordance with the Compliance Monitoring and Enforcement Program (CMEP).
- Enforce compliance with mandatory reliability standards by registered entities in accordance with CMEP, while improving quality and timeliness.
- Ensure timely and thorough mitigation of all violations of mandatory standards.
- Provide feedback and instruction to help Regional Entities perform successfully.



## Compliance Enforcement

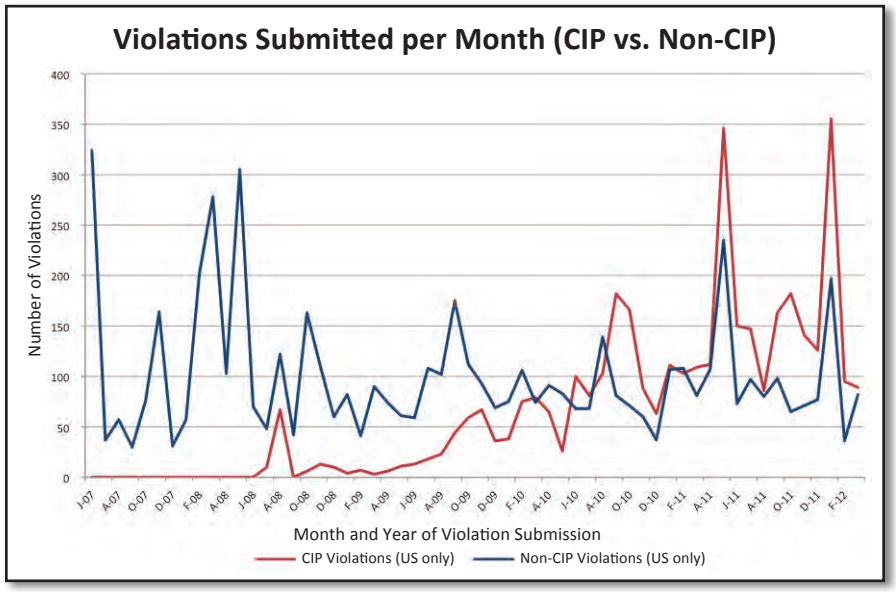
Compliance Enforcement vastly improved its efficiency in processing violations of the NERC Reliability Standards in 2011. This was accomplished by focusing resources on risks deemed most significant to the reliability of the bulk power system, and by lessening the administrative burdens associated with processing violations that impose smaller risk to the grid.

### New Initiatives

Through its Compliance Enforcement Initiative, NERC introduced two new concepts in enforcement processing: the Spreadsheet Notice of Penalty and the Find, Fix and Track (FFT) Methods of reporting. These new approaches are designed to expedite and streamline violation processing, allowing focus to be re-directed to those risks that have the most significant impact to the bulk power system. Implementation of these initiatives allows NERC to close out cases more expeditiously and provide timely lessons learned to the industry while reducing the overall ERO enforcement caseload.

### Active Violations

In the past year, the ERO's caseload of active violations expanded from 3,258 in March 2011 to 3,702 in March 2012. The rate of new violations is approximately 251 violations per month over a six month average – an increase from an average of 168 violations per month at the start of 2011. This increase is primarily attributable to the large number of violations of CIP standards that have been and are expected to continue being entered into the system. More than 60 percent of all the violations are from self-reports.




**Total Active Violations:**

| | |
|---|---|
| Mar. 2011 | 3,258 |
| Mar. 2012 | 3,702 |

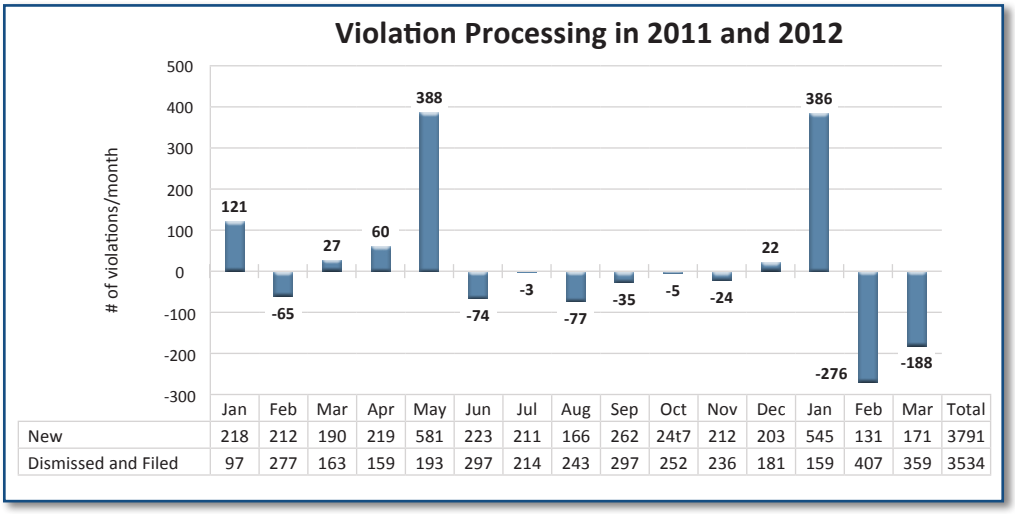
**Average Violations/Month:**

| | |
|---|---|
| 2011 | 203 |
| 2012 | 251 |

The increase in active violations can be attributed to violations of NERC's critical infrastructure protection (CIP) standards.

## Active Violations (Continued)

Compliance Enforcement processed an average of 250 violations per month in 2011. With the implementation of streamlined procedures and the advent of the FFT process, the team has processed an average of 266 violations per month for the last six months. In recent months, due to the new CEI processes, the monthly processing rate (which includes both filed and dismissed violations) has resulted in more violations being processed than submitted in eight of the last 10 months.




| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| New | 218 | 212 | 190 | 219 | 581 | 223 | 211 | 166 | 262 | 24t7 | 212 | 203 | 545 | 131 | 171 | 3791 |
| Dismissed and Filed | 97 | 277 | 163 | 159 | 193 | 297 | 214 | 243 | 297 | 252 | 236 | 181 | 159 | 407 | 359 | 3534 |

**Violations Processed Monthly (Average):**

2011 250

2012 266

Due in part to the new CEI processes, the monthly processing rate has increased.

Compliance Enforcement continues its focus on improving efficiency in the enforcement process and also plans to focus on substantially reducing its past caseload in 2012. Furthermore, implementation enhancements targeted for 2013 for the FFT process will vest the decision of processing a violation with the Compliance Enforcement Authority staff. NERC anticipates that expanding FFT will enhance the effectiveness of the program.

## Compliance Operations

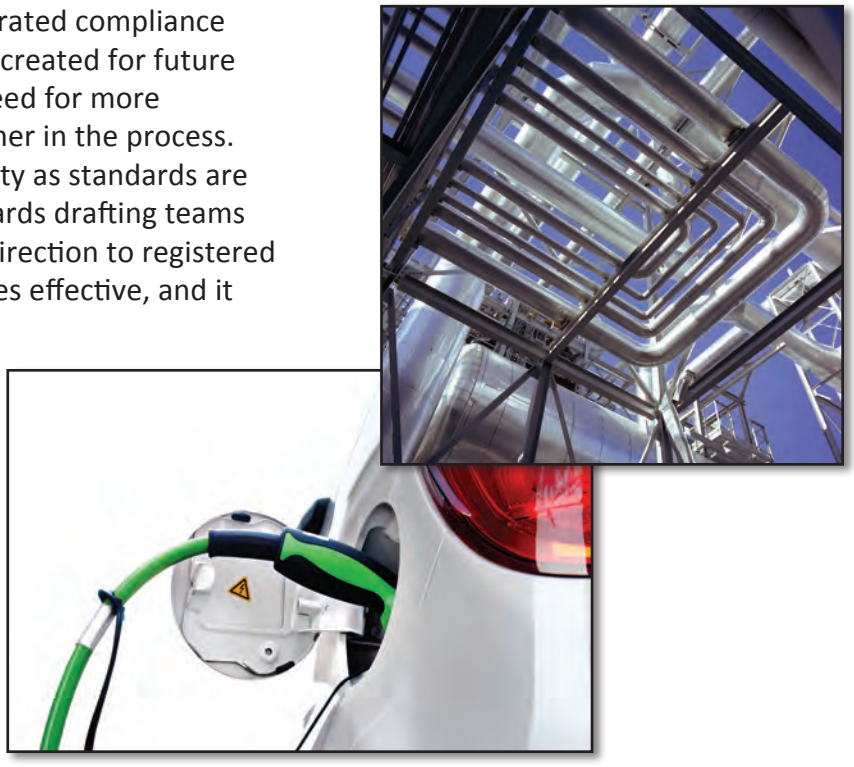
### Interface and Outreach

The Compliance Application Notices (CANs) initiative, which was developed to create compliance monitoring consistency across Regional Entities and provide transparency for compliance monitoring, completed its second year of production in 2011.

The ERO posted 25 finalized CANs that provide compliance monitoring instruction for specific issues in more than 20 reliability standards. Based on feedback from the August 2011 Members Representative Committee and Board of Trustees meeting, the CAN process was modified for greater transparency; CANs were drafted as instruction for Compliance Enforcement Authorities (CEAs), not industry; and the process was expanded to include the opportunity for industry prioritization of potential CAN issues and substantive input into the issues.

CANs support three of the pillars identified in NERC's strategy and vision: **reliability, accountability and learning**. By providing transparency into how a CEA assesses compliance to a NERC Reliability Standard, CANs provide registered entities with visibility into compliance assessments, allowing focus to shift to reliability. Transparency also supports accountability for both CEAs and registered entities. CEAs now have an ERO-wide direction on how to consistently hold registered entities accountable for compliance. Conversely, by knowing how a CEA has been instructed to assess any non-compliance issues, registered entities have the ability to hold the ERO accountable for its compliance determinations.

Although the CANs initiative has a demonstrated compliance benefit, more significant is the opportunity created for future efficiency. CAN production highlights the need for more information on compliance monitoring sooner in the process. Including more compliance monitoring clarity as standards are developed better aligns the intent of standards drafting teams with compliance expectations, it provides direction to registered entities and CEAs before a standard becomes effective, and it enables registered entities to prepare for compliance monitoring during the implementation plan with greater confidence.



## Organization Registration and Certification

### *Organization Registration*

The purpose of the Organization Registration Program is to identify and register entities that are owners, users and operators of the North American bulk power system or each entity that the ERO concludes can materially impact the reliability of the bulk power system. As described in the Statement of Compliance Registry Criteria, each of these entities is entered into the Compliance Registry and, therefore, is responsible for compliance with the NERC Reliability Standards. Identifying these organizations is necessary and prudent to begin the process of communication regarding their potential responsibilities and obligations for maintaining the reliability of the bulk power system. In accordance with the NERC Rules of Procedure, the Compliance Registry is updated on a monthly basis. As of December 29, 2011, NERC has registered 1,914 entities on the NCR for 4,722 registered functions.[1]

**Summary of Registered Entities and Functions***

| Region | Registered Entities | BA | DP | GO | GOP | IA | LSE | PPA | PSE | RC | RP | RSG | TO | TOP | TP | TSP | Total of Functions |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ERCOT | 218 | 1 | 46 | 108 | 88 | 1 | 58 | 1 | 42 | 1 | 1 | 0 | 30 | 16 | 28 | 1 | 422 |
| FRCC | 70 | 10 | 27 | 31 | 31 | 10 | 19 | 13 | 26 | 0 | 15 | 1 | 24 | 16 | 13 | 8 | 244 |
| MRO | 128 | 20 | 54 | 49 | 49 | 5 | 58 | 6 | 73 | 3 | 34 | 2 | 40 | 20 | 23 | 13 | 449 |
| NCEA | 3 | 1 | 0 | 0 | 0 | 2 | 0 | 1 | 0 | 2 | 1 | 0 | 0 | 1 | 0 | 1 | 9 |
| NPCC | 294 | 6 | 58 | 138 | 135 | 6 | 59 | 6 | 85 | 5 | 6 | 2 | 29 | 14 | 15 | 13 | 578 |
| RFC | 349 | 12 | 69 | 155 | 151 | 2 | 54 | 2 | 161 | 2 | 15 | 1 | 38 | 14 | 12 | 3 | 693 |
| SERC | 254 | 32 | 80 | 104 | 99 | 28 | 80 | 21 | 88 | 8 | 31 | 7 | 51 | 27 | 31 | 17 | 704 |
| SPP | 133 | 17 | 48 | 56 | 54 | 2 | 49 | 1 | 65 | 1 | 24 | 1 | 40 | 18 | 20 | 5 | 401 |
| WECC | 465 | 33 | 171 | 214 | 209 | 1 | 145 | 29 | 146 | 1 | 54 | 3 | 85 | 53 | 44 | 34 | 1,222 |
| **Totals** | **1,914** | **132** | **553** | **855** | **816** | **58** | **522** | **81** | **687** | **23** | **181** | **17** | **337** | **179** | **186** | **95** | **4,722** |

**Summary of Unique Entities and Functions****

| Unique Entities | BA | DP | GO | GOP | IA | LSE | PPA | PSE | RC | RP | RSG | TO | TOP | TP | TSP | Unique Functions |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1,641 | 128 | 544 | 835 | 796 | 51 | 512 | 74 | 445 | 16 | 176 | 13 | 334 | 176 | 179 | 89 | 4,368 |

1 The NCR can be found on NERC's website at: http://www.nerc.com/page.php?cid=3|25.

### *Organization Certification*

The purpose of the Organization Certification Program is to ensure that entities requesting to become a certified Reliability Coordinator, Balancing Authority or Transmission Operator have the tools, processes, training, procedures and personnel necessary to meet all applicable NERC Reliability Standards. The number of certifications, approximately 10 per year, is expected to remain fairly constant due to mergers, acquisitions, and future agreement and market changes.[2]

## Audit Assurance and Oversight

### *Reliability*

The Audit Assurance and Oversight (AAO) department participated on a number of fronts to ensure and promote the reliability of the bulk power system. Most notably, the department provided oversight to the Regional Entities for six compliance audits of registered entities. From these oversight activities, NERC identified 11 potential compliance applications, 13 positive observations and one lessons learned, and made nine recommendations to ensure the effectiveness and consistency of regional audit teams as they perform compliance monitoring activities within the ERO. Oversight findings are communicated to the Regional Entity compliance auditors at the ERO Compliance Auditor Workshop, the Compliance Monitoring Program Working Group and individually to the applicable Regional Entity audit team lead.

Other measures promoting reliability include the AAO's support of the standard development process in the drafting of *FAC-003-2 Transmission Vegetation Management*.[3] The group assisted in the review of, and proposed solutions to, industry feedback regarding technical implementation concerns on MOD-029-1a's Rated System Path Methodology and its impacts on available transfer capability. This resulted in the development of a public bulletin, "Rated System Path Methodology – Compliance Extension Request."[4]

2 Certification final reports are can be found at: http://www.nerc.com/page.php?cid=3|25|294.

3 FAC-003-2 is approved by NERC's board and posted on the NERC website at: http://www.nerc.com/files/FAC-003-2.pdf.

4 This bulletin can be found on the NERC website at: http://www.nerc.com/files/DRAFT%20Bulletin%202011-00X%20MOD-029-1a%20Compliance%20Extension%2020110718%20FINAL%20for%20Posting.pdf.

***Accountability***

In 2011, the AAO department developed several strategic programs to ensure accountability and oversight of Regional Entities' implementation of the CMEP. Of note are programs to address FERC feedback of Regional Entity compliance audits and closure of event analysis items transferred to the Regional Entities.

A transition process was developed between the Event Analysis department and the AAO. This process ensures oversight of the Regional Entities' completion of compliance activities stemming from events or investigations that occurred on the bulk power system. The AAO department provided NERC oversight of Western Electricity Coordinating Council's (WECC) spot check of Turlock Irrigation District and the Modesto Irrigation District. This spot check was performed in accordance with FERC Order NP10-18-000 from March 17, 2011.[5]

AAO provided support and expertise to the Compliance and Certification Committee (CCC) in the development of the Regional Entity Program Evaluation Procedure-CCCPP-010, approved by the NERC board. The CCCPP-010 criteria will be used in the 2012 AAO oversight of the Regional Entities' performance, per the Rules of Procedure section 402.1.2.[6] AAO also supported the CCC's spot check of the CMEP and provided audit team lead training to the auditors.

AAO completed initial audit activities on five of the eight Regional Entities in 2009 and 2010. In 2011, AAO developed the agreed-upon procedures spot check program for the three remaining Regional Entities. The program design is based on verification of identified exceptions in the previous five Regional Entities' audits. The program was completed by NERC staff in April 2011.[7]

Another form of accountability and oversight performed by the AAO includes the pilot of the Key Reliability Standard Spot Check (KRSSC). Through the review of audits performed in a relatively small window of time from each of the Regional Entities, within six months of the actual conduct of the KRSSC activities, the KRSSC was able to determine timely and effective results for compliance monitoring within the ERO. The pilot program and scope was developed in 2010 and completed in 2011 (PRC-005-1) with the results documented in a final report.[8] The KRSSC program of EOP-005-1 was initiated in 2011 with a scheduled completion date of the first half of 2012.

The AAO is the owner of the CMEP Annual Report, which is posted on NERC's website annually.[9] Also in support of accountability, AAO participated in the first FERC performance audit of PJM in 2011.

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5 See *"Order on Review of Notice of Penalty"*, 134 FERC ¶ 61,209 at P 53 and Ordering Paragraph B ("March 17 Order"). http://www.ferc.gov/whats-new/comm-meet/2011/031711/E-3.pdf.

6 See NERC RoP Section 402.1.2, http://www.nerc.com/fileUploads/File/Rules_of_Procedure/NERC_Rules_of_Procedure_EFFECTIVE_20120110_without_appendices.pdf.

7 AUP Spot Check Reports are posted on the NERC website at: http://www.nerc.com/page.php?cid=3|26|349.

8 http://www.nerc.com/files/PRC-005-1%20KRSSC%20Final%20Report-%2009142011.pdf.

9 The CMEP Annual Reports are located at the following link: http://www.nerc.com/page.php?cid=1|8.

***Risk-Based Approach***

The AAO has taken on a number of projects to bring about a risk-based approach to compliance monitoring. Foremost in these efforts is the Actively Monitored List of Reliability Standards (AML) for 2011.[10] The AML was redeveloped and reformatted to embody a three-tiered approach. The requirements with the greatest potential risk and impact have been designated as Tier 1 and are designated as the minimum audit scope for all compliance activities occurring in 2012. Tiers 2 and 3 represent the requirements that are still significant to reliability, but have a less direct link in terms of actual performance or activities.

AAO also supported the FFT Compliance Enforcement Initiative.[11] AAO contributed to the initiative's data analysis and auditor training program to ensure that regional audit staff is prepared to identify and assist registered entities in their mitigation of lesser risk issues to the bulk power system.

The AAO department supported multiple projects within and outside the Compliance Operations arena to enhance and meet the corporate objective of being a learning organization. AAO developed two webinars to educate the stakeholders and Regional Entities compliance auditors on the 2012 Actively Monitored Reliability Standards List (AML). AAO also responded to 50 compliance-related questions from stakeholders. Lastly, AAO provided audit team lead training at a workshop in February 2011.

## Operating Committee

The Operating Committee is a stakeholder committee chartered by the NERC board to proactively support the ERO mission. In December 2011, the Operating Committee approved its 2012-2016 strategic plan that provides a clearly focused five-year road map that is closely linked to the NERC President's top priority issues for bulk power system reliability for 2011. The Operating Committee's strategic plan is intended to guide its functions and core mission and provides a sustainable set of expectations and deliverables. The strategic plan restates the purpose of the Operating Committee, which it to strive for improved reliability excellence by focusing on reliability standards, communication (reporting, information, advice and understanding), priority setting, tools and training.

The Operating Committee's major accomplishments for 2011 include:

- Event Analysis Working Group Process and Lessons Learned, which links to two key priorities (misoperations of relay protection and control systems and human errors by field personnel).
- Geomagnetic Disturbance and Severe Impact Resilience Task Forces, which links to the key priority of preparedness for high-impact, low-frequency events.
- Frequency Response, which links to the key priority of the changing resource mix.

10 http://www.nerc.com/commondocs.php?cd=3.

11 Information on the CEI can be found on the NERC website at: http://www.nerc.com/page.php?cid=3|22.

# Critical Infrastructure

## Overview

During 2011, NERC's Critical Infrastructure department (CID) saw growth, change and impact. Doubling the department staff to 15 full-time employees, both compliance and security matters being addressed through information sharing, standards development and compliance, policy development, and outreach and training.

The department began the year by continuing cybersecurity standards development to ensure strong security measures for entity operations. Version 5 of the Critical Infrastructure Protection (CIP) standards were produced by building on Version 4, which was approved by FERC in April 2012). V5 provides guidance and context for each standard requirement and develops a realistic and comprehensible implementation plan for industry. To assist members in complying with NERC's CIP standards, the department worked with NERC's training staff to host workshops and webinars to better educate entities.

In addition, CID examined the Electricity Sector-Information Sharing and Analysis Center's (ES-ISAC) capabilities and activities and undertook significant efforts to refresh the ES-ISAC's overall function and utility. This includes enhancing the ES-ISAC's information-sharing mechanisms, such as updating the ES-ISAC website to better communicate with industry members about potential threats and vulnerabilities.

The department also expanded its partnerships with government agencies and industry members by hosting activities such as the Grid Security Conference (GridSecCon) 2011 and Grid Security Exercise (GridEx) 2011, working with the Department of Homeland Security to establish an agreement for placing ES-ISAC staff on the floor of the National Cybersecurity and Communications Integration Center, and collaborating with industry experts to train and educate NERC members.

Finally, CID provided input into policy considerations concerning cybersecurity as needed, particularly with respect to commenting on Government Accountability Office draft reports, participating in FERC technical conferences, and coordinating with electricity sub-sector trade associations on key policies.

CID accomplished many goals in 2011. Some goals focused on significant changes to operating practices, which entailed reorganizing processes and procedures, and measuring the impact and value activities have on registered entities. Other goals challenged the department to improve ways of serving industry through coordination with partners and better communication.

NERC's physical and cybersecurity program grew stronger throughout the year as more subject matter experts were brought in and programs were established and enhanced, which had the effect of solidifying NERC's role of ensuring the security and reliability of the bulk power system.

## Standards and Compliance

During the year, significant time was spent on developing and reviewing NERC's Cybersecurity Reliability Standards. CIP Version 4 was submitted to FERC in February 2011, and received approval in April 2012. In October 2011, NERC assembled drafting teams to work on the remaining FERC order provisions in Version 5, holding four standards drafting team meetings.

**By The Numbers – Standards and Compliance**

- 200 CIP audits performed: 90 at entity locations and 110 at regional offices
- 33 spot checks performed
- 14 CIP oversight audits performed

CID informed registered entities about the changes to the standards by offering two standard drafting team-led webinars in November 2011 to discuss posted standards prior to ballot, and a NERC-led webinar in December 2011 to discuss balloting and commenting. CID also provided subject matter expertise during 11 Project 2008-06 Cybersecurity Order 706 meetings that reviewed cybersecurity standards and addressed industry stakeholder issues.

CID also worked with the Compliance Operations department and Regional Entities to improve the consistency of compliance program results, improve risk-based approaches for auditing and spot checking, and promote a culture of security and compliance through education, transparency and incentives.

CID provided support to Compliance Operation's oversight of the Regions' audits of registered entities with CIP auditors maintaining oversight of the audit teams throughout the entire process: pre-audit, on-site and post-audit. The primary purpose of the CIP audit oversight program is to focus on the compliance monitoring process; however, CIP auditors do not make compliance determinations, rather they capture compliance applications, positive observations, lessons learned and recommendations.

The purpose of NERC's audit oversight is to perform thorough evaluations of the processes and criteria used by all Regional Entities in their determination of Registered Entities' compliance with ERO reliability standards.

During oversight audits, CID staff identifies observations and lessons learned to develop and revise Compliance Application Notices, Reliability Standard Audit Worksheets, Compliance Process Bulletins, ERO auditor training, and compliance workshops for industry.

CID also addressed the way that Technical Feasibility Exceptions (TFE) are managed. TFEs provide flexibility in implementing CIP standards and ensure that registered entities meet the intent, if not the letter, of all CIP standard requirements even when information technology systems and services differ substantially. Led by CID, NERC developed a TFE annual report that included an overview of the program and an impact analysis that was filed with FERC.

## ES-ISAC

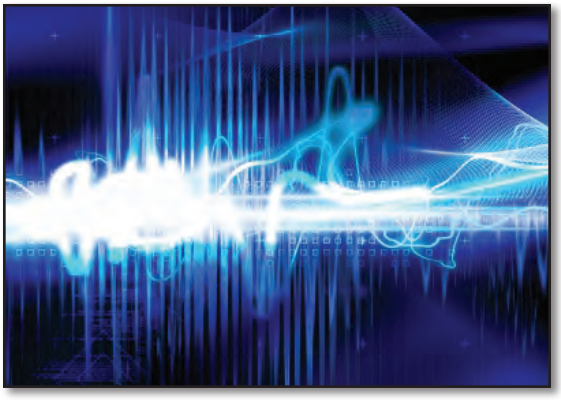
Before 2011, CID had established information sharing mechanisms through the ES-ISAC, public-private partnerships and ad-hoc information sharing avenues. However, during 2011, CID examined the ES-ISAC's functionality to ensure the ES-ISAC's tools and personnel were used to their greatest extent.

**By The Numbers – ES-ISAC**

- 7 alerts released
- 12 monthly ES-ISAC briefings, averaging more than 200 attendees per call
- Multiple classified briefings attending

The ES-ISAC revamped its website by adding a library with reports, public alerts and other relevant information; by hosting a secure, private portal to disseminate non-public alerts and sensitive information; and by providing links to industry-recognized security information resources. A pilot program to test the Members Secure Portal was launched with members of the Critical Infrastructure Protection Committee previewing the members secure portal and providing comments.

In addition to revamping the website, ES-ISAC staff identified key partners and entities to participate in the ES-ISAC for more relevant information sharing. To bolster the ES-ISAC's participation in other information-sharing activities, an agreement was made with the Department of Homeland Security (DHS) to staff the NCCIC, where other ISACs and representatives from the government and industry monitor and share threat data. The team also enhanced existing programs, such as the monthly ES-ISAC briefing series, to regularly share information and gain insight into activities within DHS, the Department of Energy, and other federal agencies. The monthly briefing series averages more than 200 participants on the calls.



ES-ISAC also reviewed the way the ES-ISAC obtains and responds to threat and vulnerability data. As a result, NERC now maintains threat and vulnerability analysis capabilities and can facilitate timely and actionable alerts. The ES-ISAC released seven alerts in 2011.

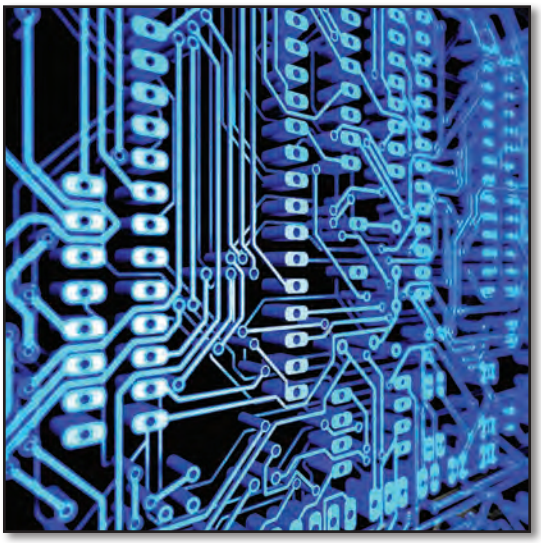
CID worked closely with federal partners to have classified threat briefings for cleared NERC members. These briefings gave insight to attendees about the threat landscape within the Electricity Sub-sector, including cross-sector threats that have cascading impacts on the Electricity Sub-sector.

## Partnerships, Outreach and Training

Two of CID's most active focus areas in 2011 were outreach and training. More partnerships were developed with key federal agencies, as well as private sector organizations. CID reached out to registered entities to gain insights and better communicate NERC activities.

### Outreach Activities

- **GridSecCon 2011:** NERC hosted its first-ever security conference focused on physical and cybersecurity issues facing the Electricity Sub-sector. More than 265 attendees from industry, law enforcement, DHS and other regulatory organizations participated. GridSecCon 2012 is October 16-18, 2012, in San Diego.



- **Cyber Risk Preparedness Assessment:** The assessment was developed to assess the current cyber resiliency capabilities of registered entities and the adequacy of existing reliability mechanisms related to the highly unique nature of cyber threats. Through these assessments, key areas for improvement can be targeted and areas of best practices can be shared with industry. One registered entity participated in the assessment in 2011.

- **Sufficiency Review Program:** The review program was developed to examine registered entities' Risk-Based Assessment Methodology, which is in NERC Cybersecurity Standard – Critical Cyber Asset Identification (002-3). The methodology must determine which assets – if destroyed, degraded, compromised or otherwise rendered unavailable - impact the reliability of the bulk power system. The program examines whether a registered entity's methodology is sufficient to ensure safe, reliable operation. Ten sufficiency reviews were conducted in 2011.

## Training Activities

- **SANS:** NERC sponsored two SANS training activities in 2011. One session in Orlando, Fla., focused on supervisory control and data acquisition/industrial control systems (SCADA/ICS); and the second session, during GridSecCon 2011, provided an overview of cybersecurity principles and current industry-related issues.

- **Idaho National Laboratory:** During GridSecCon 2011, an Idaho National Laboratory session focused on intermediate SCADA training. Additional training opportunities with the Idaho National Laboratory will take place in 2012, including during GridSecCon 2012.

- **CIP Auditor:** Auditor training is based on the Government Accountability Office (GAO) Generally Accepted Government Auditing Standards (GAGAS) for performance audits. Throughout 2011, CID participated in four training sessions on the fundamentals of compliance audits for lead auditors and two sessions on CIP standards. The compliance auditor training material is continuously being enhanced based on feedback from compliance audit experiences and changes to the policies/procedures. Additional training modules concerning GAO Auditing Standards, random sampling techniques, critical asset identification, and a review of CIP-002 sufficiency reviews—all meant for enhancing the CIP compliance auditor skills—were developed and offered to CIP compliance auditors in 2011. Four CIP auditor workshops are planned for 2012 and 2013.

- **Aurora webinars:** In response to the Aurora vulnerability discovered in 2007, CID has worked with registered entities to address and mitigate the vulnerability. CID established reporting dates throughout 2011 for registered entities to communicate their progress in addressing the vulnerability. Five Aurora webinars with more than 1,600 attendees took place in 2011.

## Policy Development Activities

Throughout the year, CID provided subject matter expertise into different types of policy documents, including the joint Risk Management Framework. The framework was developed by the Department of Energy and the National Institute of Standards and Technology with input from subject matter experts from NERC and entities. The guideline is a voluntary framework for security cyber systems beyond those needed for bulk power system reliability. The framework, which will be finalized in 2012, is a tiered approach for managing various levels of risks, including emerging vulnerabilities.

CID initiated the Crisis Response Plan to document how NERC will respond to a crisis on behalf of the industry by communicating with government and the media. The plan does not identify operational responsibilities, but it outlines coordination activities, and roles and responsibilities. The plan was drafted in 2011 and tested during GridEx 2011. Lessons learned from GridEx 2011 will be added to the document and finalized in 2012.

CID worked with Critical Infrastructure Protection Committee leadership to develop a strategic plan for 2012 that aligns with ERO goals and priorities. CID also managed and provided input into ESCC task force reports—primarily the Cyber Attack Task Force—by identifying attack methods and prevention mechanisms.

Through these activities, the Critical Infrastructure department enhanced NERC's cybersecurity standards, and served as cybersecurity subject matter experts for the industry in policy, information sharing and threat assessment.



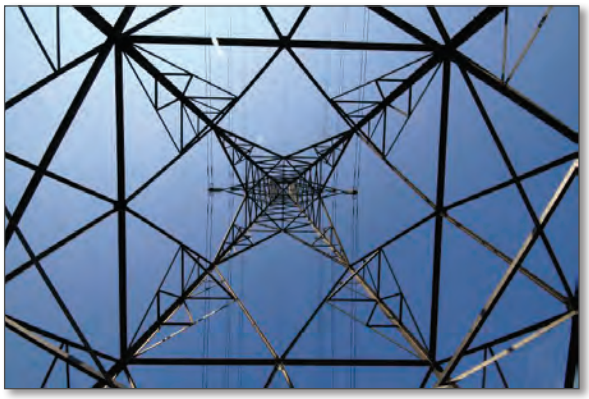
# Reliability Assessment and Performance Analysis

## Overview

The Reliability Assessment and Performance Analysis (RAPA) program assesses, measures and investigates historic trends and future projections to establish an understanding of the current state of reliability to improve of bulk power system reliability. In order to address this commitment, the program identifies the historic and projected high-priority reliability issues and associated risks, analyzes and benchmarks historic and projected performance, and identifies areas for bulk power reliability improvement and industry learning opportunities. To accomplish this, RAPA focuses its mission in three areas: Reliability Assessment, System Analysis and Reliability Initiatives, and Performance Analysis and Reliability Metrics.

With the support of NERC's technical committees, especially the Planning Committee, RAPA delivered a number of key independent reliability assessments and further improved on the metric development work started in 2009. RAPA also made progress in measuring the performance of the bulk power system, furthering the effort to define the relative risk to reliability from system conditions, events and standard violations.

In 2011, collaboration with Sandia National Laboratories and the Energy Information Administration identified methods to improve the value of the new indices, such as the severity risk index (SRI). Based on the resulting recommendations,[1,2] risk cluster and other statistical analysis methods will be considered to link the reliability data used in event driven index,[3] standards driven index (SDI)[4] and condition driven index (CDI) to identify significant initiating events and their relative reliability impact.



1 http://www.nerc.com/docs/pc/rmwg/pas/Mar_2012_OCPC/Final_Memo_Sandia.pdf

2 http://www.nerc.com/docs/pc/tadswg/07_agenda%20item%20EIA%20Memo.pdf

3 http://www.nerc.com/docs/pc/rmwg/pas/Mar_2012_OCPC/EDI_Whitepaper.pdf

4 http://www.nerc.com/docs/pc/rmwg/Integrated_Bulk_Power_System_Risk_Assessment_Concepts_Final.pdf

## Reliability Assessments

NERC's Reliability Assessment program conducts annual, seasonal and long-term reliability assessments that are designed to assess the resource adequacy and operating reliability of the bulk power system based on industry preparations and plans. The assessment program also identifies and analyzes key issues that may affect reliability, such as market practices, industry trends, environmental regulations and policy measures.

In 2010, the Reliability Assessment program assessed the impacts of a variety of issues affecting bulk power system reliability. Assessments on integration of variable generation and smart grid, demand forecast uncertainty following a recession, and environmental regulations were highlighted.

In 2009, the NERC Integration of Variable Generation Task Force published a summary report, which included a three-year work plan for identifying reliability issues and recommendations for maintaining reliability while integrating high-levels of variable generation. In 2011, more than a dozen task groups – comprised of more than 200 industry experts – continued tackling this work plan releasing four reports and recommendations that were completed in 2011 on topics including modeling, wind forecasting, distributed generation integration reliability standards and flexibility metrics for planners requirements.

### Additional 2011 Reliability Assessments

- **Seasonal Assessments – Summer (May) and Winter (November)**
  The 2011 summer assessment showed pockets of demand were being reduced due to economic conditions with the aggregate summer forecast demand remaining flat in comparison with the 2010 summer operating period. This report included metrics on reserve margins, demand response, seasonal climatological forecasts, water resources and geomagnetic disturbances to provide insights on historical summer reliability trends and identify important trends to watch.

  Observations from the 2011/2012 Winter Reliability Assessment were similar to the 2011 Summer Reliability Assessment and also included four cold-snap lessons learned from industry outlining best practices for winter preparation learned from the January/February 2011 cold weather event in the southwestern United States.

- **Long-Term Reliability Assessment – October**
  NERC's annual ten-year reliability outlook provides an independent view of the reliability of the bulk power system, identifies trends, emerging issues and potential concerns. NERC significantly increased the scope of its long-term reporting by assessing transmission system adequacy and providing deeper analysis of emerging reliability issues. This report also represented a shift from reviewing reliability issues on a Regional Entity basis to reviewing reliability issues by assessment areas. This report discussed the key issues and risks to bulk power system reliability, including the economic recession; the continuing change in generation fuel mix during the next ten years; vital transmission development; and industry coordination and communication.

- **Potential Impacts of Future Environmental Regulations – November**
  This insert into the 2011 Long-Term Reliability Assessment updated the *2010 Special Reliability Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*. The Environmental Protection Agency (EPA) is in the process of promulgating four regulations: the proposed Coal Combustion Residuals rule, the proposed Mercury and Air Toxics Standards for Utilities, the proposed Cooling Water Intake Structures rule -316(b), and the final Cross-State Air Pollution rule. This report had five key conclusions, including areas focused on compliance with state, federal, local regulations, regionality of natural gas usage for bulk power system capacity throughout North America; improving coordination between gas suppliers and electricity generators; improving operating controls; and removing uncertainty with future regulations. This report highlighted a number of recommendations and directed them to appropriate policy groups, including NERC, regulators and industry stakeholders.

- **Geomagnetic Disturbances: Monitoring, Mitigation, and Next Steps A Literature Review and Summary of the April 2011 NERC GMD Workshop – November**
  The objective of this report was to summarize the NERC Geomagnetic Disturbance (GMD) Workshop that took place in April 2011 and to provide a review of the current literature on GMDs. This report summarized the proceedings and increased the awareness of operational and technology-based practices and approaches to mitigate the effects of severe GMDs. This document provides the views of presenters, and overview of discussions that occurred during the face-to-face meeting.

- **Post Seasonal Assessments – 2010 Summer (June) and 2010/2011 Winter (September)**
  Post seasonal assessment reports allow NERC staff, Regional Entities and stakeholders to review important facts about previous operating seasons and discuss lessons learned in planning and operations to be highlighted in future assessments. These assessments reviewed the seasonal peak demand in each assessment area, the day-ahead peak demand forecast, the differences between these forecasts, and the month of occurrence of the peak demand. These assessments also reviewed planning and operating challenges that were experienced and how these problems were resolved to maintain the reliability of the bulk power system.

- **2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States – December**
  The majority of new generating capacity projected in the next ten years will rely on natural gas as its primary fuel. This report reviewed gas and electric interdependencies, assessed existing and future challenges, identified areas of vulnerability, and provided recommendations for enhancing bulk power system reliability. The increased dependence on natural gas for generating capacity can amplify the bulk power system's exposure to interruptions in natural gas supply and delivery. This report also detailed strategies to cope with events related to this interdependency, including storage, firm fuel contracting, alternate pipelines, dual-fuel capability, sufficient pipeline capacity to support normal and emergency operations, access to multiple natural gas basins, or additional transmission lines from other areas – all can help mitigate and manage potential risks to reliability.

## Reliability Initiative and System Analysis

The Reliability Initiative and System Analysis (RISA) program provides engineering expertise focused on protection and control along with system analysis and modeling to study system disturbances, develop reliability guidelines, and support NERC Reliability Standards development.

### RISA Major Accomplishments

- Conducted analysis of and published the *Analysis of Power System Impacts and Frequency Response Performance: February 1-4, 2011 Texas and Southwestern U.S. Cold Snap*.
- Co-led teams of the FERC/NERC September 8, 2011 Pacific Southwest disturbance investigation in the areas of planning, modeling and simulations, sequence of events development, and system protection and controls performance analysis.
- Established program as an internal engineering consulting service for other areas across NERC.
- Provided subject matter expertise to standards development, serving on drafting teams in the areas of system protection, modeling, frequency response, operating reserves, and the definition of the bulk electric system.
- Provided technical support to a number of notices and training sessions in the Compliance Application Notice program.
- Coordinated technical support and provided input to a number of FERC informational filings.
- Coordinated and lead technical support for FERC Orders 733, 733a and b, 754, and 758, working with the associated NERC technical subcommittees and standards drafting teams.

### RISA Key Reliability Initiatives

- **North American Synchro-Phasor**: Build-out continued in 2011 of the ten synchro-phasor installation programs across the United States that received funding from the Smart Grid Investment Grant program under the American Recovery and Reinvestment Act. As a result, hundreds of synchro-phasors will be installed, giving urgency to the development work on applications for planning and operations. Significant progress was also made in the Western Interconnection Synchro-phasor Project development of its data sharing, display, and analytical capabilities as part of that funding.
- **System Protection Improvements**: Significant progress was made with Federal Energy Regulatory Commission's approval of Standard PRC-023-1 – Transmission Relay Loadability. RISA staff members chaired or participated on a number of key IEEE Power System Relay Committees as part of a collaboration strategy on the System Protection Initiative.

The RISA program also continued work on a number of protection-related technical documents in 2011, including *Use of Circuit Breaker Position Indication in Breaker Failure Protection* technical reference document; *Transmission System Phase Backup Protection* reliability guideline; and *Procedures for Modeling Development and Validation*, which was approved by the Planning Committee in 2011.

## Performance Analysis and Reliability Metrics

Reliability metrics efforts are focused on the development of a comprehensive and interrelated suite of metrics that support a culture of bulk power system reliability performance, as well as quantify and prioritize reliability risks.

### Performance Analysis Major Accomplishments

- Published the *2011 Risk Assessment of Reliability Performance* report. The 2011 Risk Assessment of Reliability Performance is a foundational report, with the goal to provide view of risks to reliability based on historic performance. Notable findings were that a team should be created to study common and dependent mode outages and that more data collection is necessary to gauge the reliability of the bulk power system. The report also recommended that a transition to a "State of Reliability" report should be done to quantitatively assess the reliability of the bulk power system.
- Development of a Spare Equipment Database began in response to recommendations in the June 2010 joint NERC, Department of Energy report – *High Impact, Low Frequency Event Risk to the North American Bulk Power System*. The database will be populated and managed by participating organizations, facilitating timely communication between entities needing long-lead time to replace damaged equipment – which will be extremely helpful in the aftermath of a high impact, low frequency event, such as coordinated attack or extreme weather.
- Implemented the first demand response availability database (DADS) in North America. DADS will enable NERC to receive, manage, assess and disseminate data on demand response programs, products and services administered by retail and wholesale entities throughout North America. DADS performance metrics and data will improve demand response projections by providing load forecasters, resource planners and analysts with a comprehensive database for NERC of demand response programs.
- Continued to develop and support additional conceptual framework. During the year, Sandia National Laboratories provided an in-depth review of the current framework. The resulting recommendations will be a key consideration as the risk assessment focus progresses in 2012. Maintained an interactive, dynamic reliability indicators display comprised of 18 reliability metrics and the Severity Risk Index.[5] The enhanced view provides meaningful dimensions of reliability condition-driven indicators and their trends aggregated at NERC and at the regional level.

5 http://www.nerc.com/page.php?cid=4|331

- Introduced Generation Availability Data System (GADS), mandatory data collection for units 50 MW and greater. Prior to 2011, GADS data submission was voluntary and comprised approximately 70 percent of NERC-wide generation. With mandatory collection of units 50 MW or greater, this will comprise more than 90 percent of NERC-wide generation.
- Formulated and began development on an online data entry and collection portal for the GADS. This system, webE-GADS, will enhance the collection efficiency and analysis capability of GADS information.

In 2012, RAPA will continue to address emerging industry issues identified compliance trends and event analysis trends will become the foundation of a risk register that will serve to enhance prioritized risk control project selection. Further analysis of special risk control projects to examine the nature of issues such as relay misoperations and cold weather impacts will address interconnection and NERC-wide opportunities to improve bulk power system reliability.



Photo courtesy of WECC

# Reliability Risk Management

## Overview

In September 2011, NERC consolidated the Event Analysis and Investigations group with the Situation Awareness group. Additional subject matter expertise in human factors/performance was added to this new group. The organizational change strategically improves NERC's commitment to reliability excellence and risk management by combining the technical resources, expertise and functions into one department.

The primary functions of the group are:

- Capture and report creditable system awareness information for bulk power system events and system conditions.
- Conduct robust event analysis, using cause analysis and risk-based methods.
- Facilitate and ensure that lessons learned and any necessary reliability communications are issued to industry stakeholders in a timely manner.
- Retain a strong enforcement authority by ensuring that any necessary investigations are independent, objective and at a level consistent with the expectations of the industry and government.



## Bulk Power System Awareness

NERC's Bulk Power System Awareness group and the eight Regional Entities monitor bulk power system conditions for the 12 Reliability Coordinator regions in North America to maintain an awareness of emerging situations that could impact the reliable operation of the bulk power system. The System Awareness group also monitors security threats to the electric sector and supports the development and publishing of alerts and awareness products.



Awareness of system events also provides an opportunity for NERC to analyze and determine event causes, supports the development of lessons learned, and contributes to the ability to trend reliability performance. Initial situation awareness monitoring and trending, along with other means to analyze events, allows for a thorough and accurate event analysis process.

The strength of the System Awareness group lies with the Reliability Coordinators and their communication with each other, with entities in their footprint, with their respective Regional Entity and with NERC. System Awareness supports NERC in providing leadership coordination, technical expertise and assistance to the industry in responding to events. To accomplish these goals, NERC will:

- Maintain real-time situation awareness of conditions on the bulk power system using the Situation Awareness for FERC, NERC, and the Regional Entities, Version 2 (SAFNR V2) real-time monitoring system being implemented in second quarter 2012.
- Notify the industry of significant bulk power system events that have the potential to impact reliability in other areas.
- Maintain and strengthen high-level communication, coordination and cooperation with governments and government agencies, Reliability Coordinators and Regional Entities regarding real-time conditions. This is accomplished through the implementation of NERC's Crisis Response plan during high-impact, low-frequency events.
- Maintain a 24-hour, on-call duty officer to receive and act upon emergency communications.

## Situation Awareness for FERC, NERC, and Regional Entities, Version 2 (SAFNR V2)

SAFNR V2 was developed by the SAFNR project team during 2010 to be a centralized application that utilizes reliability coordinator-supplied data to populate an overview of the bulk power system. The SAFNR V2 design team, made up of subject matter experts from FERC, NERC, the Regions and the Reliability Coordinators, developed centralized application specifications, developed a project request for proposal, and evaluated prospective vendor bidders during the 2010 calendar year. One of the overarching goals of the SAFNR team has been to continually improve and enhance NERC's performance as the ERO. NERC expects the SAFNR V2 system to be fully functional and operational by third quarter 2012.

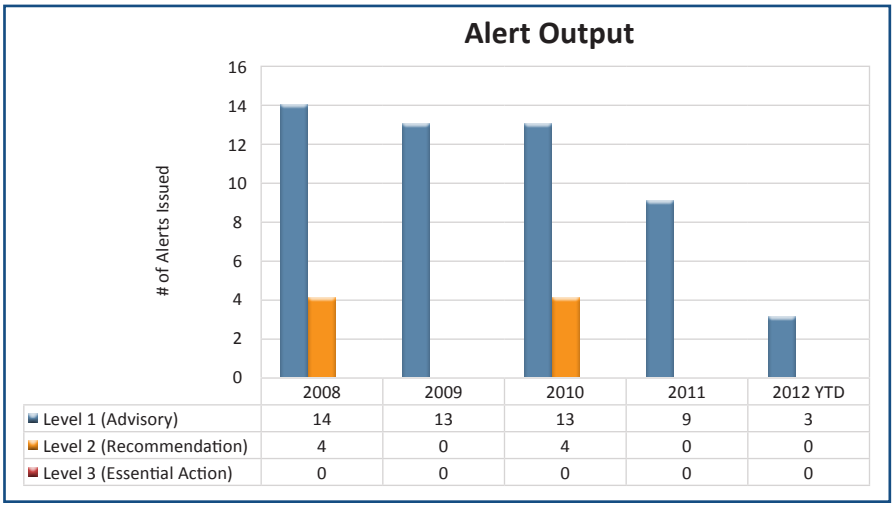
As part of its normal course of business, NERC often discovers, identifies or is provided with information that is critical to ensuring the reliability of the bulk power system in North America. In order to effectively share this information, NERC uses e-mail based "alerts" designed to provide concise, actionable information to the electricity industry. NERC alerts are divided into three levels:

- **Industry Advisory:** Informational, intended to alert registered entities to issues or potential problems. A response to NERC is not necessary.
- **Recommendation to Industry:** Recommend specific action be taken by registered entities. Require a response from recipients as defined in the alert.
- **Essential Action:** Identify actions deemed to be "essential" to BPS reliability. Require NERC Board of Trustees approval prior to issuance. Like recommendations, essential actions also require recipients to respond as defined in the alert.

NERC distributes alerts broadly to users, owners and operators of the bulk power system in North America. Alerts may be targeted to groups of entities based on their registered functions (e.g.; Balancing Authorities, Planning Authorities, Generation Owners, etc.).

In 2011, NERC System Awareness published nine alerts and assisted with the development of two.

In 2012, so far: NERC System Awareness published three alerts and assisted with the development of one.




| | 2008 | 2009 | 2010 | 2011 | 2012 YTD |
|---|---|---|---|---|---|
| Level 1 (Advisory) | 14 | 13 | 13 | 9 | 3 |
| Level 2 (Recommendation) | 4 | 0 | 4 | 0 | 0 |
| Level 3 (Essential Action) | 0 | 0 | 0 | 0 | 0 |

## Event Analysis

The primary function of the Event Analysis group is to conduct technically sound event analysis using cause analysis and risk-based methods. Additionally, the group facilitates industry training in this critical area, and ensures lessons learned and related reliability communications are issued to industry stakeholders in a timely manner.

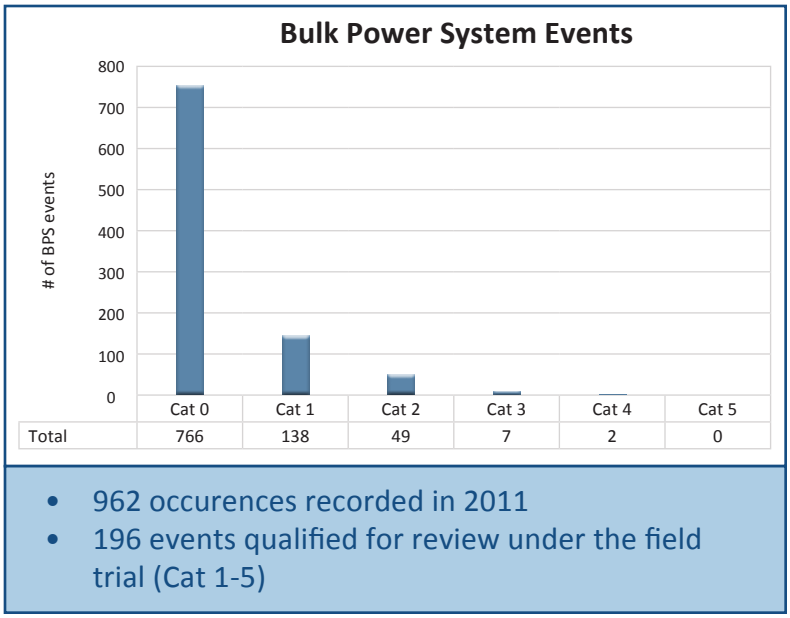
## ERO Event Analysis Process

NERC began a field trial of the ERO Event Analysis Program in 2010 to engage bulk power system owners, operators and users in determining root causes developing and sharing lessons learned and other improvement opportunities from bulk power system events. One of the ultimate goals of the program is to facilitate the rapid sharing of lessons learned from selected system events and trends that provide industry benefit through enhanced reliability. The Events Analysis Process was approved by the NERC Board of Trustees and became effective in February 2012.

The Events Analysis group receives brief reports, event analysis reports, and lessons learned from registered entities for qualifying bulk power system events. The group then systematically catalogs, prioritizes and assesses this event information for opportunities to improve bulk power system reliability.

In 2011, there were 962 bulk power system events reported through the ERO EA Process; of these, 196 were qualifying events. From October 2011 to January 2012, 117 candidate lessons were suggested from industry. Additionally, the group developed and currently maintains a public webpage allowing interested stakeholders access to these lessons learned and best practices. NERC posted 22 lessons learned to the website in 2011.

This process has driven a significant decrease in the initiation of compliance investigations by NERC and Regional Entities. The expectations established by this process and the response of registered entities by providing more and better information concerning bulk power system disturbances has enabled a more complete compliance assessment than was possible without the use of a formal Compliance Monitoring and Enforcement Program method.

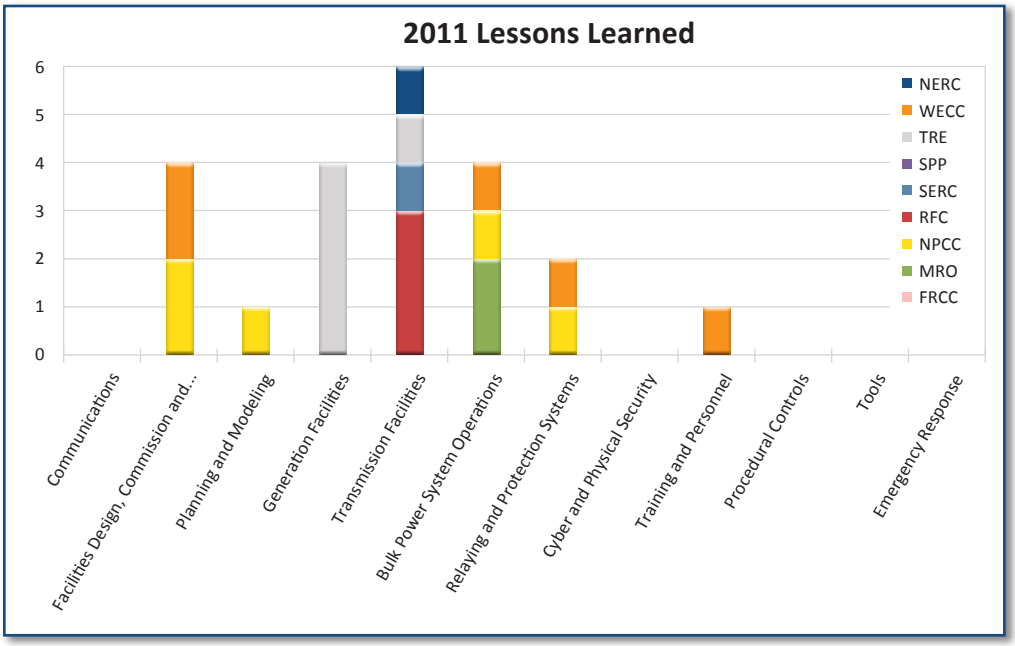



- 962 occurences recorded in 2011
- 196 events qualified for review under the field trial (Cat 1-5)

## Event Analysis of the Southwest Cold Weather Event

NERC initiated a joint inquiry with the FERC in response to the extreme cold weather conditions that occurred in the southwestern region of the United States during the first week of February 2011. These conditions led to the significant loss of generation capacity and the implementation of extensive firm load shedding, particularly in the ERCOT Interconnection. NERC and FERC combined their efforts to issue a joint report that determined the adequacy of preparations and identified the causes of the various generator failures, gas shortages and rolling blackouts, and made recommendations to help prevent a recurrence of similar events.

Additionally, NERC issued a companion report that analyzed the performance of the bulk power system during the event. NERC published eight lessons learned identified during this event to ensure reliable operation for future cold weather events. As follow-up, NERC drafted a Standard Authorization Request to address gaps identified in the reliability standards for Emergency Operations Planning, conducted a webinar on the recommendations from the joint report, and conducted regional surveys to assess winter preparedness for the upcoming 2012-2013 winter season.




**22**

**Total Number of Lessons Published in 2011**

## Investigations Group

The Investigations group, in collaboration with the Regional Entities' compliance staff, evaluates significant bulk power system events against the NERC Reliability Standards, conducts compliance investigations, and addresses complaints relating to reliability standards.

A compliance investigation is a confidential, non-public process used to review circumstances or events that indicate a reliability standard may have been or is being violated. Initiation may arise from a complaint or an event on the bulk power system.

Complaints, often made anonymously, are submitted to NERC through an electronic portal, as well as a toll-free number directed to a voice mailbox. Each of these is carefully evaluated on its merits by investigation staff, following established processes.

## Human Performance

In July 2011, NERC began its human performance initiative by resourcing a human performance program within the Reliability Risk Management group. Human error is often cited as the cause or as a contributing factor in a large percentage of the events and occurrences that threaten the reliability of the bulk power system. In support of the NERC Event Analysis Program, the *Cause Analysis Methods for NERC, Regional Entities, and Registered Entities* was published and includes a chapter on human performance evaluations. This publication includes tools, techniques and procedures to include the human factor into the considerations of why events occur.

NERC provided support to regional initiatives by providing expertise for events, such as the Human Performance Working Group at WECC, and presenting human performance updates to different NERC standing committees. Several registered entities hosted visits by NERC human performance staff who offered guidance, assistance, information and training, including results of trending analysis and techniques and procedures being used by other industries to reduce human error.

NERC sponsored the first "Improving Human Performance on the Grid" conference the first quarter of 2012. The focus of the collaborative sessions was on human performance awareness and sector-specific subject matter experts and stakeholders operating in a cooperative forum. The conference provided tools and resources to get in front of errors. Human performance fundamentals are still some of the best lines of defense for stopping events on the bulk power system. NERC alerts, lesson learned and best practices will specifically address some of the challenges related to the reduction of human error.

# Standards

## Overview

One of NERC's core responsibilities is to ensure the reliability of the bulk power system by developing effective reliability standards that are clear, consistent and technically sound. All bulk power system owners, operators and users must comply with these standards, which define the requirements for planning, operating and protecting the reliability performance of the North American electrical grid, so that widespread cascading outages, uncontrolled separations and blackouts do not occur. NERC's standard development process is American National Standards Institute (ANSI)-accredited and guided by key reliability and market-interface principles. It is the users, owners and operators of the bulk power system in the United States, Canada and parts of Mexico who both develop NERC's mandatory reliability standards and implement them to ensure reliability. NERC's success depends on the accountability of its stakeholders, including active participation from the industry on standards drafting teams, during comment periods and in ballot pools.

Standards activities are primarily guided by three documents: the Reliability Functional Model, a guide that defines the specific functions that need to be performed to operate the bulk power system reliably; the Standard Processes Manual, which outlines the standard development process; and the Reliability Standards Development Plan, which serves as the management tool that guides, prioritizes and coordinates revision or retirement of existing reliability standards and the development of new reliability standards for the immediate three-year time horizon.

NERC is always working to improve its standard development processes and the quality of the standards it produces. To that end, several new tools and processes were implemented in 2011, including project prioritization and standards process enhancements. NERC also continued work on FERC reliability directives throughout the year, along with its regular stakeholder outreach and standard development activities.

## Project Prioritization

In February 2011, NERC's Board of Trustees endorsed a standards project prioritization process and related tool developed by the Standards Committee in coordination with NERC staff. The prioritization process was developed because too many standard development projects were underway, and the Standards Committee needed a methodology for determining which projects should be developed ahead of others. Under this approach to prioritization, NERC and the Standards Committee give priority to projects that have regulatory deadlines; projects that close reliability gaps; and projects for which there is a demonstrated need to improve the clarity of existing standards. The prioritization process balances consideration of all prioritization criteria and assists the Standards Committee in making informed decisions about the use of NERC and industry resources.

Following the implementation of the tool, NERC standards staff continued work on the 12 highest priority projects, as well as projects scheduled for completion in the first quarter of 2011. They also responded to new regulatory and policy priorities as they emerged. Projects that were already underway, but were not identified as having the highest priority, shifted into an informal development stage.

## Standards Process Enhancements

To improve the efficiency and quality of its standards process while adhering to the Standard Processes Manual approved in 2010, standards staff implemented quality reviews and began utilizing an ANSI-compliant approach called "rapid revision." In coordination with the Standards Committee, standards staff also initiated a review of the standards process to identify possible improvements and efficiencies.

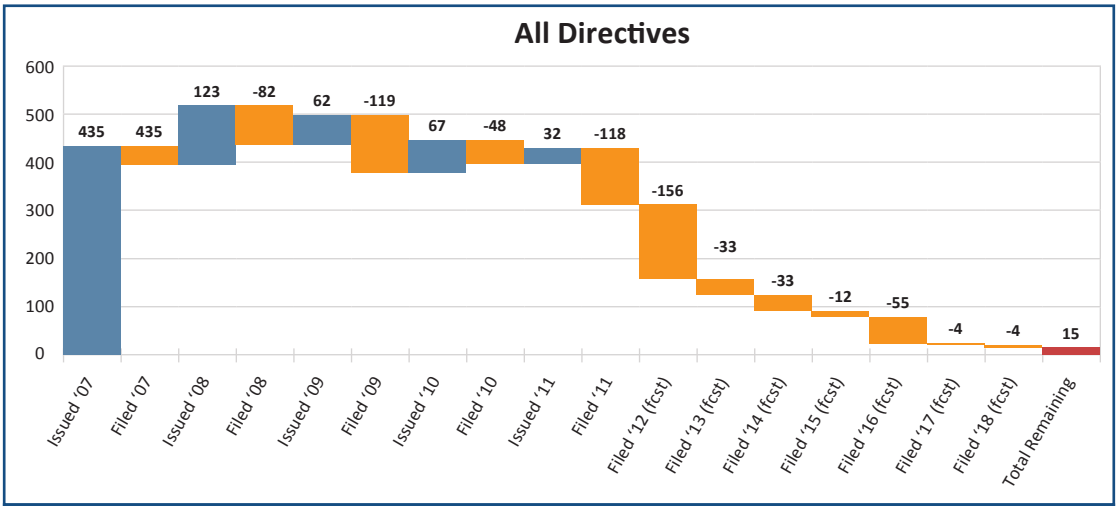
The quality review process was Introduced in the Standard Processes Manual, and fully implemented in 2011 to require a quality review of a "final draft" of a standard and its associated documents. The purpose of the quality review is to assess whether it is within the scope of the associated Standard Authorization Request, are clear and enforceable as written, and meet the criteria specified by NERC and FERC. Quality reviews are conducted by NERC staff and trained stakeholders who represent standards, legal and compliance backgrounds. Feedback is returned to the drafting team for consideration before a standard is posted for industry comment and ballot, increasing the quality and clarity of the posted documents. In 2011, 45 quality reviews of standards and interpretations were conducted.

The "rapid revision" approach is taken if a standard needs a minor clarification. Rather than process the clarification as an interpretation, this process allows a drafting team to propose changes to the standard to provide the necessary clarification and submit the modified standard with an associated Standard Authorization Request to the Standards Committee. Following Standards Committee review, the changes may move directly to comment and ballot. The approach was successfully tested with Project 2011-INT-01 Interpretation of MOD-028-1 R3.1 for Florida Power and Light, where a permanent change to the standard was posted for stakeholder review and successfully balloted within three months. A subcommittee of the Standards Committee will continue work to refine and formalize the rapid revision process.

In October, standards staff and the Standards Committee initiated a process to identify additional improvements and efficiencies in the existing NERC Reliability Standards Development Process. The objective is to make the process less labor intensive for the industry and increase throughput with resources currently being applied from both the industry and NERC. This effort will continue in 2012 in close coordination with the Standards Process Input Group, a task force created by the Member Representatives Committee for the purpose of reviewing NERC's standards development processes. The initiative will consider the quality of standards, the timeliness of standard development, the efficiency and effectiveness of the standards process, and the importance and significance of meeting ANSI requirements.

## Addressing FERC Directives

Since NERC was certified as the ERO, FERC has issued 50 orders containing approximately 721 directives related to NERC Reliability Standards. The majority of the directives, 435, were issued in 2007. Of the approximately 721 directives issued since 2007, NERC has initiated and completed projects associated with 58 percent of these directives, and continues to make substantial progress in addressing the remaining directives, using the prioritization process to focus first on those that have the greatest impact on reliability. NERC responded to, and filed with FERC, standards responsive to 118 directives in 2011 and plans to respond to an additional 156 directives in 2012.




**FERC Issued Directives (as of December 31, 2011)**

This chart summarizes NERC's activity on FERC directives from 2007 to 2011 and forecasted activity through 2018.

## Stakeholder Outreach

As part of its efforts to reach out to stakeholders and share information about its latest projects, NERC hosted two Reliability Standards and Compliance Workshops (in Salt Lake City and Atlanta with webinar options available) and one State of Standards webinar. Together, these events reached nearly 1,000 industry participants. This effort will continue in 2012 with two in-person workshops and another State of Standards webinar. In addition to the workshops and State of Standards webinar, standard drafting teams had 18 webinars to keep stakeholders informed of technical issues associated with 12 standards projects.

The Standards department implemented two major changes to improve the timeliness of standards information to stakeholders. First, in August 2011, standards staff introduced an enhanced United States enforcement dates web page. Four different enforcement date-related reports are now available: Standards Subject to Enforcement; Standards Subject to Future Enforcement; Standards Pending Regulatory Approval; and Inactive Standards. These pages include essential dates and links related to NERC Board of Trustees adoptions, NERC filings and FERC orders. In 2012, standards staff plans to similarly improve the enforcement date pages for the Canadian provinces.

Secondly, in November 2011, standards staff began issuing a weekly standards bulletin to keep stakeholders informed of open comment periods and ballots, along with upcoming ballots, standard drafting team vacancies, and other standards-related postings and events.

## Major Project Deliveries and Other Standards Activity

In response to a November 2010 FERC directive in Order 743, the definition of Bulk Electric System was revised to encompass all elements and facilities necessary for the reliable operation and planning of the interconnected bulk power system. The proposed definition of Bulk Electric System, the implementation plan and a draft application form, "Detailed Information to Support an Exception Request," were approved by industry ballot in November 2011. These documents were filed with FERC on January 25, 2012.

Work on Critical Infrastructure Protection standards also continued in 2011. Under NERC's Cybersecurity Order 706 standard drafting team, Version 4 of the CIP standards was filed with FERC in February 2011, and approved April 2012. These revisions aim to replace the existing requirement for a risk-based assessment with a set of bright-line criteria for use in determining a set of critical assets. After Version 4 standards were filed, standards drafting teams began work to address the remaining standards-related directives of FERC Order No. 706. The Version 5 CIP cybersecurity standards were posted for their first concurrent comment and ballot period in November 2011.

NERC's board approved 17 significant continent-wide standards, three regional standards, one regional variance and conforming changes to another four standards. The board also approved three interpretations, which have been filed or are in the process of being filed with FERC. NERC also posted 52 standards for comment periods and conducted 55 ballots. Of the 55 ballots, 34 were initial ballots (including two for interpretations), two were successive ballots, and 19 were recirculation ballots (including two for interpretations). In keeping with the effort to focus on a finite number of high priority projects, only two Standard Authorization Requests were posted during 2011.

With these initiatives, NERC has taken significant steps to improve the quality and efficiency of its standard development processes. NERC, working with its stakeholders, is committed to delivering standards that provide for the reliability of the bulk power system in 2012 and beyond.

# Training

## Overview

NERC's Training and Education program provided oversight and coordination for the delivery of training programs that support the ERO and industry needs, including workshops, webinars and training courses. The program also supported the System Operator Certification and Continuing Education programs, which ensure that personnel operating the bulk power system have the skills, training and qualifications needed to operate the system reliably.

## Certification

NERC maintained the credentials required to work in system control centers across North America for more than 6,200 system operators. NERC's system operator certification exam is designed to test specific knowledge of job skills and reliability standards. It also prepares operators to comply with requirements of reliability standards and appropriately operate the bulk power system during normal and emergency operations. In 2011, 874 exams were administered across North America with 607 new certified system operators, for an overall exam pass rate of 69.5 percent. Additionally, the content outlines for each exam – Reliability Operator, Transmission Operator, Balancing Authority and Balancing/Interchange/Transmission – were updated based on a job task analysis survey conducted the previous year. During the second half of 2011, NERC, the Personnel Certification Governance Committee and the Exam Working Group developed new exams for publishing in early 2012.

**By The Numbers – Certification**

- 874 exams administered
- 607 new certified system operators
- Overall exam pass rate of 69.5 percent
- 1,691 system operator certifications renewed

Once an operator passes the certification exam, certification is maintained by completing 150 to 200 hours of NERC-approved continuing education courses and activities over a three-year credential period. In 2011, 1,691 system operator certifications were renewed after obtaining the required continuing education hours. The Personnel Subcommittee, composed of industry training experts, provides oversight of the Continuing Education program.

## Continued Education

The Continuing Education Review Panel and support staff reviewed more than 2,500 individual learning activities and provider applications during the year. A total of 275 learning activity audits were conducted in 2011, averaging nearly 70 per quarter. These randomly selected audits of learning activities promote consistency and adherence to NERC's Continuing Education Program requirements by training providers. In the last year, the industry conducted more than 411,000 hours of approved continuing education for the industry's certified system operators. The continuing education hours for each operator are maintained in the System Operator Certification and Continuing Education Database managed and operated by NERC staff. During the year, NERC continued to enhance the database to improve features, displays and functionality to better support the needs of operators, training providers, and staff as recommended in the three-year assessment. Improvements are based on recommendations from the Personnel Certification Governance Committee, Personnel Subcommittee and industry users.

## Other Training Events

During the year, numerous workshops and webinars were conducted to provide learning opportunities for NERC, Regional Entity and industry personnel. These activities covered current topics for compliance, enforcement, standards, assessments, reliability risk management, and critical infrastructure.

ERO auditor workshops provided continuing education for compliance auditors. Ongoing auditor training was completed by nearly 95 NERC and Regional Entity staff members, along with nearly 70 participants in the quarterly Audit Team Leader training courses. Nearly 1,500 ERO and industry personnel participated in workshop sessions and webinars for the implementation of the Compliance Enforcement Initiative. In addition, a new Causal Analysis course was developed and delivered in 2011 that includes root-cause methods, human performance principles and event analysis techniques. In the fourth quarter, a new on-line learning system was selected and tested for flexible delivery of personal development and business skills training for NERC staff in 2012.

# NERC Regional Entities

## FRCC

**Florida Reliability Coordinating Council** operates in peninsular Florida east of the Apalachicola River within the Eastern Interconnection.
*Sarah Rogers, president and chief executive officer (through April 30, 2012)*
*Stacy Dochoda, president and chief executive officer (as of May 1, 2012)*

## MRO

**Midwest Reliability Organization** covers roughly one million square miles spanning the provinces of Saskatchewan and Manitoba; the states of North Dakota, Minnesota and Nebraska; the majority of Iowa, South Dakota and Wisconsin; and portions of Michigan and Montana. The Region includes more than 100 organizations that are involved in the production and delivery of power to more than 20 million people.
*Daniel Skaar, president and chief executive officer*

## NPCC

**Northeast Power Coordinating Council, Inc.** includes New York and the six New England states, as well as the Canadian provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia. Overall, NPCC covers an area of nearly 1.2 million square miles, populated by more than 55 million people.
*Edward Schwerdt, president and chief executive officer*

## RFC

**ReliabilityFirst Corporation** operates across 13 states and the District of Columbia. The 13 states are New Jersey, Delaware, Pennsylvania, Maryland, West Virginia, Ohio, Indiana, lower Michigan and portions of upper Michigan, Wisconsin, Illinois, Kentucky, Tennessee and Virginia.
*Timothy Gallagher, president and chief executive officer*

## SERC

The **SERC Reliability Corporation** is a nonprofit corporation responsible for promoting and improving the reliability, adequacy and critical infrastructure of the bulk power supply systems in all or portions of 16 central and southeastern states. Owners, operators and users in these states cover an area of approximately 560,000 square miles.
*Scott Henry, president and chief executive officer*

## SPP

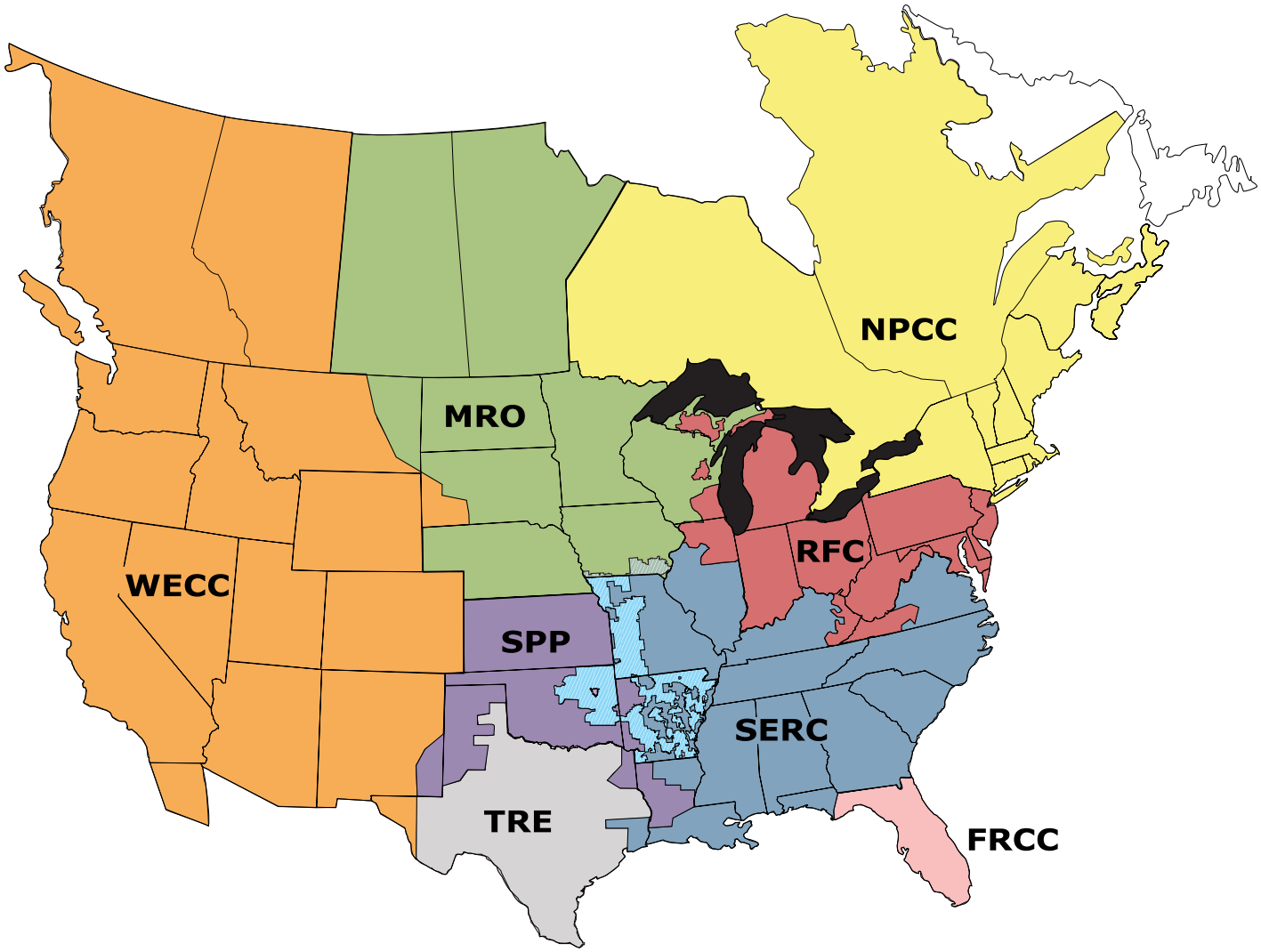
The **Southwest Power Pool Regional Entity** is an independent and functionally separate division of SPP, Inc. SPP RE promotes and improves bulk power system reliability within an eight-state area that includes all or parts of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas.
*Stacy Dochoda, general manager (through April 30, 2012)*
*Ron Ciesiel, acting general manager (as of May 1, 2012)*

## TRE

**Texas Reliability Entity, Inc.** operates within the geographic boundaries of the Electric Reliability Council of Texas (ERCOT) region. The ERCOT region is located exclusively within Texas and represents 85 percent of the state's electric load and 75 percent of the Texas land area.
*W. Lane Lanford, president and chief executive officer*

## WECC

**Western Electricity Coordinating Council's** territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between, which totals approximately 1.8 million square miles.
*Mark Maher, chief executive officer*



# Message from the Chairman of the Board

As we complete our fifth year as the ERO, the NERC Board of Trustees continues to oversee NERC's strategy and direction with an eye on our mission – to ensure the reliability of the bulk power system in North America. This year showed results from our maturing experience and relationships with our stakeholders and with U.S. and Canadian regulators. We continue to be interested in finding ways to balance a need for comprehensive solutions to reliability risks, with a realistic appraisal of how to use limited resources – those of NERC, as well as those of stakeholders who must implement the systems, processes and standards required to ensure reliability – and pay for the efforts of NERC and the Regions.

One result of our gained experience is the development and testing of a framework for dealing with low risk violations that was asked for by stakeholders, as well as regulators. Rather than use a full compliance process that relies on detailed investigation and negotiation to resolve violations that are considered low risk, NERC developed a Find, Fix, Track and Report system that is a fast, efficient, improved process. This approach has the potential to reduce the time and effort it takes all parties to deal with low risk violations, freeing up time to focus on activities that have higher impacts on reliability.

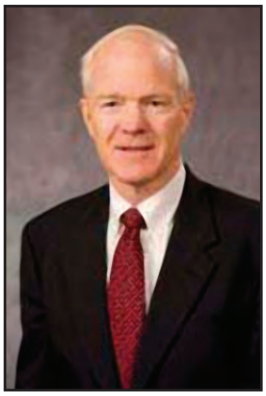
Similarly, the board gave NERC management the task of developing detailed and fact-based reports to help stakeholders, government regulators and legislators make decisions on laws and regulations that can have large impacts on electric reliability. These reports come from the wide range of stakeholder expertise that NERC committees and task forces can bring to bear on complex issues, with a careful focus on technical excellence, thorough examination of facts and scenarios, and unbiased reporting of findings and implications. Examples of areas that we reported on were geomagnetic disturbance impacts on electric system reliability, the cumulative effect of proposed environmental regulations on reliability, and the potential affects that high-impact, low-frequency events can have on the electric system.

The NERC board continued its program to have individual trustees meet with stakeholders and regional management teams, as well as Regional Boards of Directors. These outreach efforts provided excellent input for the trustees to gain a first-hand feel for the challenges and successes as our standards are implemented and followed at the working level.

Much was accomplished in 2011 and the board continues to be energized and enthusiastic about continuing this important work to ensure that users, owners and operators of the bulk power system in Canada and the United States have excellent reliability with reasonable expenditures of effort and money. On behalf of the Board of Trustees, I look forward to 2012 and to moving ahead, focused on our mission and objectives.

John Q. Anderson
Chairman,
NERC Board of Trustees

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Draft
# 2013 Business Plan and Budget

~~May~~June 4, 2012

RELIABILITY | ACCOUNTABILITY



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# About NERC

## Overview

The North American Electric Reliability Corporation (NERC) is a not-for-profit entity organized under the New Jersey Nonprofit Corporation Act. NERC's mission is to improve and ensure the reliability of the bulk power system in North America. NERC's area of responsibility spans the continental United States and Canada and the northern portion of Baja California, Mexico. Entities under NERC's jurisdiction are the users, owners, and operators of the bulk power system – a system that serves the needs of over 334 million people, includes installed electricity production capacity of approximately 1,200 gigawatts, operates 211,000 miles of high voltage transmission, and is comprised of assets worth more than one trillion dollars.

The Federal Energy Regulatory Commission (FERC or Commission) certified NERC as the Electric Reliability Organization (ERO) within the United States to establish and enforce reliability standards for the United States portion of the bulk power system, pursuant to section 215 of the Federal Power Act. NERC is subject to regulatory oversight by FERC.

In Canada, NERC presently has memoranda of understanding with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, Saskatchewan, and Alberta, and with the National Energy Board of Canada. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro, making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and the Northeast Power Coordinating Council (NPCC) have been recognized as standards setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NERC standards are now mandatory in British Columbia and Nova Scotia.

## Scope of Responsibilities

As the ERO, NERC's primary responsibilities are leading the development, improvement, and adoption of reliability standards for the bulk power system in North America and the monitoring, evaluating, and enforcement of compliance with those reliability standards by the approximately 1,900 entities registered with NERC as bulk power system users, owners, and operators. Collectively, these entities perform over 4,600 bulk power system reliability functions. In addition, NERC conducts near-term and long-term assessments of the reliability and future adequacy of the North American bulk power system; certifies bulk power system operators as having and maintaining the necessary knowledge and skills to perform their reliability responsibilities; maintains situational awareness of events and conditions that may threaten the reliability of the bulk power system; coordinates efforts to improve physical and cyber security for the bulk power system of North America as it relates to reliability; and

conducts detailed analyses and investigations of system disturbances and unusual events to determine root causes, uncover lessons learned, and issue relevant findings as advisories, recommendations, and essential actions to the industry. All of these activities serve the broad public purpose of helping to improve and ensure the reliability of the bulk power system.

The Energy Policy Act of 2005[1] and the events leading up to it set the stage for NERC's evolution from the NERC Council to its current role as the ERO. NERC's objective both before and after becoming the ERO is to promote and improve the reliability, adequacy, and security of the bulk power system in North America. ~~Building upon NERC Council's forty-year old programs, v~~Voluntary compliance with operational and planning protocols by certain sectors of the industry was replaced with mandatory and enforceable reliability standards for users, owners and operators of the bulk power system in North America.

A series of FERC orders set the parameters of permissible statutory activities in the United States In Order No. 672, the Commission found that "section 215 of the FPA provides for federal authorization of funding limited to the development of Reliability Standards and their enforcement, and monitoring the reliability of the Bulk-Power System.[2] In certifying NERC as the ERO, the Commission held that "[w]e generally believe that *anything* required of the ERO or a Regional Entity by the statute, Order No. 672 pursuant to the statute, or any subsequent Commission order pursuant to section 215 of the FPA is a statutory activity."[3] In Order No. 693, the Commission held that section 215 also "contemplates the prevention of incidents, acts and events that would interfere with the reliable operation of the Bulk-Power System."[4]

For the last six years, under the Commission's oversight and approval, NERC has undertaken a ~~wide range of~~specific activities and programs[5] in support of the implementation of its statutory responsibility to develop and support ~~–~~reliability standards, enforcement of ~~or~~and achieving compliance with these standards and ~~conducting periodic~~ assess~~ments~~ing of the reliability and adequacy of the bulk power system in North America.[6]

[1] This was codified in section 215 of the Federal Power Act, 16 United StatesC. 824o.

[2] *N. Am. Elec. Reliability Corp.*, 114 FERC ¶ 61,104 at P202 (2006) (Order No. 672).

[3] *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 at P185 (2006) (emphasis added). *See also N. Am. Elec. Reliability Corp.*, 132 FERC ¶ 61,217 at P 45 n.33 (2010)..

[4] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 24,

[5] These programs include: (1) Reliability Standards Program; (2) The Compliance Enforcement and Organization Registration and Certification Program; (3) The Reliability ~~Readiness Evaluation and Improvements~~Assessment and Performance Analysis Program; (4) The Training, Education and Operator Certification Program; and (5) The Situation Awareness and Infrastructure Security Program.

[6] *See, e.g., Request of NERC for Acceptance of its 2007 Business Plan and Budget and the 2007 Business Plans and Budgets of Regional Entities and for Approval of Proposed Assessments to Fund Budgets*, Docket No. RR06-3-000, filed Aug. 23, 2006 ("2007 ERO Budget Filing"), at 21-34. and *Request of the North American Electric Reliability Corporation for Acceptance of its 2008 Business Plan and Budget and the 2008 Business Plans and Budgets of Regional Entities and for Approval of Proposed Assessments to Fund Budgets*, Docket No. RR07-16-000, filed Aug. 24, 2007 ("2008 ERO Budget Filing"), at 45-56~~*See also*~~, *N. Am. Elec. Reliability Corp.*117 FERC ¶ 61,091 (2006) ("2007 ERO Budget Order"); *N. Am. Elec. Reliability Corp.*, 121 FERC ¶ 61,057 (2007) ("2008 ERO Budget Order"); *N. Am. Elec. Reliability Corp.*, 125 FERC ¶ 61,056 (2008) ("2009 ERO Budget Order") (finding that "NERC's 2009 Business Plan provides sufficient details for us to determine whether NERC intends to perform appropriate activities" and that "NERC's proposed categories of activities for 2009 . . . reasonably fall within the types of activities the Commission considers to be covered by FPA section 215," *id.* at P 18) and *N. Am. Elec. Reliability Corp.*, 128 FERC ¶ 61,025 (2009); *N. Am. Elec. Reliability Corp.*, 129 FERC ¶ 61,040 (2009) ("2010 ERO Budget Order"); *N. Am. Elec. Reliability Corp.*, 133 FERC ¶ 61,062 (2010) ("2011 ERO Budget Order"); *North American Electric Reliability Corp.*, 137 FERC ¶ 61,071 (2011) ("2012 ERO Budget Order").

In an effort to further improve transparency, NERC's 2013 Business Plan and Budget provides more granular detail regarding the specific activities which will be undertaken by NERC's program areas and the departments within those program areas in order to provide stakeholders with an opportunity to further understand and provide input regarding the scope of NERC's proposed activities in relation~~ship~~ to its responsibilities as the ERO under section 215 of the Federal Power Act.

## Membership and Governance

Membership in NERC is open to any person or entity that has an interest in the reliability of the North American bulk power system. Membership in NERC is voluntary and affords participants the opportunity to engage in the governance of the organization through election to the Member Representatives Committee. The number of entities and individuals who are members is nearly 600.

A twelve-member Board of Trustees (Board) governs NERC (11 independent directors plus the CEO serving as the management trustee). The Board has formed several committees to facilitate its oversight of the organization in the areas of finance and audit, governance and human resources, compliance, standards oversight and technology, and nominations. In August 2011, upon recommendation of the Finance and Audit Committee and with the support of stakeholders, the Board approved the formation of a Risk Management and Internal Controls Subcommittee (RMICS) comprised of all of the members of the Finance and Audit Committee, the chair of the Compliance and Certification Committee and the president of the Regional Entity Management Group.[7]

NERC's Member Representatives Committee (MRC) comprises 28 voting representatives elected from the 12 membership sectors. The MRC elects the independent trustees, along with the Board votes on amendments to the Bylaws, and provides policy advice and recommendations to the Board on behalf of stakeholders with respect to annual budgets, business plans, and other matters pertinent to the purpose and operations of the organization.

## Delegated Authorities

In executing a portion of its responsibilities, NERC delegates authority to Regional Entities to perform certain functions through delegation agreements. FERC has approved delegation agreements between NERC and eight Regional Entities (Florida Reliability Coordinating Council, Midwest Reliability Organization, Northeast Power Coordinating Council, Inc., Reliability*First* Corporation, SERC Reliability Corporation, Southwest Power Pool RE, Texas Reliability Entity, Inc. and the Western Electricity Coordinating Council). These delegation agreements describe the authority delegated to the Regional Entities in the United States to propose and enforce reliability standards within their geographic footprints. NERC expects Regional Entities, whose territories extend into Canadian provinces~~a~~ and Mexico, to perform equivalent functions in those jurisdictions.

[7] ~~To view t~~The RMICS mandate is available at http://www.nerc.com/docs/bot/finance/FAC05-08-12a-OPEN-complete.pdf

NERC and Regional Entity personnel are actively engaged in numerous activities in support of ERO objectives and in carrying out their respective responsibilities under the delegation ~~agreements .~~agreements. At the senior executive level, the ERO Executive Management Group, comprised of the chief executive officers and associated management staffs of NERC and the eight Regional Entities, provides strategic policy guidance and operational direction for the activities of the ERO enterprise (NERC and the Regional Entities) through coordinated decision-making to execute the Regional Entities' responsibilities under the delegation agreements and the NERC Rules of Procedure. As part of its efforts to ensure efficient and effective use of resources while executing the statutory responsibilities of the ERO across the ERO enterprise, the ERO Executive Management Group also manages a series of working groups and subcommittees, including:

- Regional Standards Group
- Certification and Registration Working Group
- ERO Compliance and Enforcement Management Group
- Compliance Monitoring Processes Working Group
- Enforcement, Sanctions and Mitigation Working Group
- CIP Compliance Working Group
- Training and Education Group
- Reliability Assessments and Performance Analysis Group
- Legal Working Group
- Information Management Group
- Information Technology Steering Group
- Regional Communicators Group
- ERO Finance Group

NERC and the Regional Entities have worked cooperatively to address the costs incurred (as well as the amount of time spent) by the Regional Entities for processing compliance violations, by implementing the "Find, Fix, Track and Report" (FFT) and the "Spreadsheet Notice of Penalty" (Spreadsheet NOP) enforcement alternatives to the development of a full NOP for every Alleged Violation. NERC presented the FFT and Spreadsheet NOP enforcement alternatives to the Commission in a petition filed on September 30, 2011,[8] and the Commission accepted this filing in an order issued March 15, 2012.[9] The FFT and Spreadsheet NOP enforcement mechanisms will be used for Possible Violations that pose lesser risk (minimal risk

[8] *Petition Requesting Approval of New Enforcement Mechanisms and Submittal of Initial Informational Filing Regarding NERC's Efforts to Refocus Implementation of its Compliance Monitoring and Enforcement Program*, Docket RC11-6-000, filed Sept. 30, 2011.
[9] *North American Electric Reliability Corporation, Order Accepting with Conditions the Electric Reliability Organization's Petition Requesting Approval of New Enforcement Mechanisms and Requiring Compliance Filing*, 138 FERC ¶ 61,193 (2012) ("FFT Order").

in the case of the FFT) to the bulk power system and satisfy other criteria. Where a Possible Violation is dispositioned using the FFT or the Spreadsheet NOP mechanism, the Regional Entity will not have to expend time and resources to the same extent as to develop the documentation required for a full NOP filing; rather, the record is aligned to the risk posed by a given Possible Violation and all relevant information is included in a spreadsheet format. Where a Possible Violation is dispositioned through the FFT mechanism, the Regional Entity will not have to expend the time and resources to negotiate a formal settlement agreement, process a separate formal Mitigation Plan through acceptance and approval, or determine a Penalty or sanction for the violation. The availability of the FFT and Spreadsheet NOP enforcement mechanisms will significantly reduce the total amount of resources expended by the Regional Entities in processing compliance violations. In the FFT Order, the Commission stated that NERC's proposal "will be the first step to a more efficient and effective compliance and enforcement process"[10] and that "we believe that the FFT proposal may significantly reduce the time and resources needed to resolve minor possible violations of Reliability Standards and thereby permit NERC and the Regional Entities to reprioritize their compliance efforts toward more important violations and matters."[11]

Earlier, NERC had adopted other approaches to improve the efficiency of Regional Entity violations processing and dispositioning, including an Abbreviated Notice of Penalty Format, a Deficiency Notice of Penalty Format, and an Administrative Citation Notice format. The Commission has stated that the Abbreviated Notice of Penalty Format and Deficiency Notice of Penalty format "have been successful in increasing efficiency" and that it expected the Abbreviated Citation Notice Format "will be a successful tool in improving the efficiency of NERC's enforcement process, thereby reducing the time and resources expended by the Regional Entities, NERC and Commission staff while still achieving transparency and consistency in penalty determinations for violations that are appropriate for this format."[12]

## Funding

Section 215 of the Federal Power Act and FERC regulations also specify procedures for NERC's funding in the United States. NERC's annual business plan and budget is subject to FERC approval in the United States. Once approved, assessments are allocated to load-serving entities on a net energy for load (NEL) basis. Equivalent funding mechanisms are provided in Canada, subject to the specific laws and regulations of each province.

The funding requirements for each Regional Entity are addressed separately in each Regional Entity's business plan and budget, which must be reviewed and approved by NERC and FERC in the United States. Assessments for the Regional Entity budgets are included in the overall NERC assessments to load-serving entities.

[10] FFT Order at P 41.
[11] FFT Order at P 40.
[12] *North American Electric Reliability Corporation, Notice of No Further Review of Initial Administrative Citation Notice of Penalty*, 134 FERC ¶ 61,157 (2011) at P 7.

# Introduction and Executive Summary

| TOTAL RESOURCES (in whole dollars) | 2013 Budget | U.S. | Canada | Mexico |
|---|---|---|---|---|
| Statutory FTEs | 186.25 | | | |
| Non-statutory FTEs | | | | |
| **Total FTEs** | 186.25 | | | |
| Statutory Expenses | $ 54,021,949 | | | |
| Non-Statutory Expenses | $ - | | | |
| **Total Expenses** | $ 54,021,949 | | | |
| Statutory Inc(Dec) in Fixed Assets | $ (128,617) | | | |
| Non-Statutory Inc(Dec) in Fixed Assets | $ - | | | |
| **Total Inc(Dec) in Fixed Assets** | $ (128,617) | | | |
| Statutory Working Capital Requirement | $ (250,000) | | | |
| Non-Statutory Working Capital Requirement | | | | |
| **Total Working Capital Requirement** | $ (250,000) | | | |
| Total Statutory Funding Requirement | $ 53,643,332 | | | |
| Total Non-Statutory Funding Requirement | $ - | | | |
| **Total Funding Requirement** | $ 53,643,332 | | | |
| | | | | |
| **Statutory Funding Assessments** | $ 48,897,332 | | | |
| **Non-Statutory Fees** | | | | |
| NEL | - | | | |
| NEL% | 0.00% | | | |

## Strategic Goals and Objectives

NERC's mission is to improve and ensure the reliability of the bulk power system of North America. NERC furthers this mission by developing clear, reliability-focused standards; promoting compliance excellence with its reliability standards; providing firm but fair enforcement of mandatory reliability standards; assessing and reporting on existing and future reliability performance; analyzing and reporting on system events to identify and share lessons learned; maintaining the system operator certification program; and facilitating industry awareness and management of risks to reliability.

Each year, senior management from NERC and the Regional Entities devote considerable time and effort to the business planning and budgeting process, including refining and updating goals, objectives, deliverables, and common multi-year business planning and budgeting assumptions, taking into account lessons learned and stakeholder feedback, as well as

applicable governmental requirements and directives. NERC's Board also participates in strategic planning, building on input from NERC and the Regional Entity Management Group.

The 2013 strategic planning initiative produced the following common goals and objectives:

1. **Standards and Compliance**
   a) Develop clear, reasonable and technically sound mandatory reliability standards in a timely and efficient manner. These standards establish threshold requirements for ensuring the bulk power system is planned, designed, operated, and maintained in a manner that minimizes risks of cascading failures, avoids damage to major equipment, or limits interruptions of bulk power supply.
   b) Be a strong enforcement authority that is independent, without conflict of interest, objective and fair. The ERO will retain and refine its ability to use standards enforcement when warranted and impose penalties and sanctions commensurate with risk.
   c) Promote a culture of compliance with mandatory reliability standards across the industry. The ERO will support the industry by identifying procedures, practices and controls to address reliability risks resulting from noncompliance.
2. **Risks to Reliability**
   a) Identify the most significant risks to reliability. The ERO will identify and prioritize reliability risks, develop effective solutions and interventions, and monitor results.
   b) Be accountable for mitigating reliability risks. The ERO will work with industry stakeholders and experts to ensure the mitigation of known risks to reliability using standards enforcement and other methods where appropriate.
   c) Promote a culture of reliability excellence. The ERO will facilitate a learning environment throughout the industry through event causal analysis, communication of lessons learned, tracking of recommendations, and implementation of best practices.
3. **Coordination and Collaboration**
   a) Improve transparency, consistency, quality and timeliness of results. The ERO will accomplish this through effective coordination, collaboration and process improvements.
   b) Operate as a collaborative enterprise. The ERO will communicate expectations clearly and foster collaboration to deliver important results in advancing system reliability.
   c) Improve efficiencies and cost effectiveness. The ERO will accomplish this by engaging the support of stakeholders, being an efficient steward of resources, and leveraging information systems to create efficiencies and process controls.

## Focusing on Priorities

In furtherance of the foregoing strategic goals and objectives, NERC will be focusing on a number of high priority items for 2013 including:

- Issuing new and revised standards, including the development of results-based standards, as well as working with industry, applicable governmental authorities and other stakeholders to improve the standards development process.
- Continuing to improve enforcement focus, efficiency and productivity, including working with regulatory authorities and stakeholders to develop and implement improvements in the enforcement framework which focuses both ERO and industry resources on compliance activities that are most likely to support the reliability of the North American bulk power system.
- Regional Entity collaboration, coordination and oversight.
- Improving the ability of industry to respond to incidents, vulnerabilities, and threats that have the potential to adversely affect ~~the~~ bulk power system reliability.
- Educating stakeholders on the role and long-term strategy for the ES-ISAC.
- Event analysis, emerging issues and reliability risk reporting.
- Developing and implementing improvements to ERO processes, including the design and deployment of necessary IT infrastructure to facilitate these process improvements, and improvements in internal financial and operating controls.
- Improving compliance information and education.
- Enhancing reliability risk metrics and modeling capabilities.
- Training of ERO staff and stakeholders.

## Challenges

NERC, along with the Regional Entities and industry participants in the ERO, continue to face a number of challenges and demands as they work to achieve the ERO's strategic objectives. The more significant challenges include:

- Improving the standards development process;
- Focusing on reliability risk and delivery of results;
- Continuing to improve the compliance enforcement framework, focus and processes;
- Identifying and addressing critical infrastructure protection priorities;
- Addressing regulatory mandates;
- Continuing to ~~i~~implement~~ing~~ the improvements identified in the Three-Year ERO Performance Assessment;
- Balancing resource needs within financial constraints, and achieving efficiencies; and
- Recruiting, integrating and retaining qualified personnel.

## 2013 Key Assumptions

As mentioned above, NERC and the Regional Entities' Business Plans and Budgets reflect a set of common assumptions, attached as Exhibit A. The significant assumptions underlying NERC's 2013 Business Plan include:

1. The legal framework under which NERC and the Regional Entities operate will continue, including authorization to engage in the activities which the NERC and the Regional Entities have historically engaged in as being within the scope of Section 215 of the Federal Power Act;
2. The final determination of what constitutes the Bulk Electric System may affect the scope of ERO jurisdictional facilities and will likely impact both NERC and Regional Entity resource requirements;
3. There will be continued industry participation to support key program areas including but not limited to standards development, event analysis, and reliability assessments;
4. External factors, including regulatory actions and assessing the impacts o~~f~~f new technologies will continue to affect resource needs and allocation;
5. ERO, industry and regulatory resources will focus on improvements in the standards development process;
6. Critical infrastructure protection will continue to be a priority in the United States and Canada;
7. Continued refinement of risk-based methodologies to support more effective and efficient compliance monitoring and enforcement will mitigate compliance resource needs;
8. The frequency of compliance audits will transition to be more reflective of a registered entity's reliability risk profile;
9. Current trends in the number of new alleged standards violations each month will continue (e.g., violations of Order 693 standards gradually trending downward and violations of cyber security standards continuing to increase);
10. The number of events requiring review and analysis will increase but are not expected to materially impact resource requirements; and
11. Significant investments will be required over the planning period to develop and implement program area and enterprise-wide applications to support business needs, including compliance, registration and tracking systems and other project, data management and analysis tools to provide greater cost efficiency and uniformity across the ERO Enterprise.

## 2013 Key Deliverables

Consistent with the list of priority items emerging from its strategic planning initiative, the following is the list of significant NERC deliverables for 2013.

**Reliability Standards**

- Work with industry to implement process changes to improve efficiency and timeliness of high priority reliability risk mitigating standards.
- Implement process changes to facilitate the removal of administrative requirements where feasible and improve throughput of standards addressing emerging reliability risks while reducing burdens on industry associated with ????.
- Support the three-year Standards Development Plan.[13]
- Reduce backlog of FERC Directives, as well as improve tracking and reporting of directives implementation.
- Improve the quality of standards drafting, training and communications.
- Track and report standards process results on a quarterly basis.
- Provide technical comments in the standards development process.
- Increase standards development coordination with compliance and enforcement.

**Compliance Operations**

- Develop a compliance trial program which provides an opportunity for mitigation while achieving compliance, as well as an opportunity to validate compliance measures and procedures.
- Develop risk-based compliance monitoring approaches to maximize reliability benefits and improve efficiencies.
- Continue education programs regarding effective compliance programs and risk controls.
- Continue to ~~i~~improve oversight of Regional Entity ~~oversight~~activities, including facilitating the development of highly qualified compliance and audit staff.
- Improve consistency and transparency.
- Increase ~~standards~~ support for standards activities to foster the development of standards with increased reliability benefit while minimize compliance risk uncertainties.
- Continue to review and update registration and certification templates and documents.

**Enforcement**

[13] http://www.nerc.com/files/RSDP2012-2014_BOT_Approved_2011NOV03.pdf

- Achieve greater efficiencies in enforcement processing by focusing attention and resources on cases having the most significant impact on reliability.
- Sustain and expand the Find, Fix, Track, and Report process within the scope of the Commission's directives.
- Reduce ~~prior~~outstnading caseload of previously identified Possible Violations and Alleged Violations .
- Identify the causes and trends in violations.

**Reliability Assessments**

- ~~Complete and obtain Board approval of a revised definition of adequate level of reliability (ALR).~~
- Issue reliability assessment reports, guidelines, recommendations and alerts.
- Develop risk control strategies and plans to address existing and emerging reliability risks.
- Support standards development process and response to FERC Directives.
- Provide support and leadership to the Planning Committee, and Standing Committees' subcommittees, working groups, and task forces serving the Standing Committees.
- Build and sustain an enterprise reliability assessment and performance analysis team.
- Subject to final regulatory action, finalize Bulk Electric System and consequential load loss exception processes.

**Event Analysis and Investigations**

- Use of more sophisticated cause codes for analysis.
- Refinement of risk-based methodologies to support more effective and efficient identification of reliability risks.
- Provide timely publication of lessons learned and recommendations and track responses to recommendations.
- Refine the criteria and process for self-analysis of events and disturbances to promote continuous improvement and information sharing.

**Situation Awareness**

- Ongoing SAFNR support of FERC, Regional Entity and stakeholder needs.
- Respond to increased number of occurrences requiring analysis.
- Manag~~ing~~e a consistent program for issuing NERC alerts.

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**Human Performance**[14]

- Conduct semi-annual three-day ERO Human Performance workshops.
- Facilitate the transfer of information in terms of best practices, lessons learned and industry innovations in the area of human performance to include possible routine publications and notices.
- Continue to identify opportunities and methods for improvement based on proven methods from other industries and continue to lead an industry-wide program to improve human performance components of bulk power system reliability.

**Critical Infrastructure Protection**

- Support
  - CIP standards development;
  - Compliance Operations department oversight of Regional Entity CMEP audits;
  - Training and awareness initiatives;
  - Electricity Sub-sector Coordinating Council; and
  - CIP Compliance Working Group
- Continue to enhance information sharing and dissemination of bulk power system threat and vulnerability information through Electricity Sector Information Sharing and Analysis Center (ES-ISAC).
- Conduct security incident analysis and information sharing.

**Training and Education**

- Expansion of training and education programs including:
  - CIP standards information
  - Development and implementation of clear and technically sound reliability standards
  - Key lessons learned and trends from events
  - Identified themes from trending and common cause analyses
  - Risk-based assessment methods
  - Effective compliance cultures with practices, procedures and controls to address reliability risks
  - Effective root, apparent and common cause analysis methods
  - Quality improvement of registered entity self-reporting and self-certification

[14] See further updates on NERC's Human Performance initiatives on under the Relialibty Risk Management Department discussion commencing on page ___.

  - Currently monitored standards
  - Reliability assessment/system planning fundamentals and requirements
  - Entity registration process, issues, and alternatives
  - Human performance error reduction techniques
- Upgrades to the system operator certification and continuing education database.

**Information Technology**

- Design and deploy a common, enterprise-wide technology platform.
- Design a reliable, stable, secure environment for data gathering and reporting through a single repository of data; Phase I data warehouse design.
- Enhanced disaster recovery of critical IT resources.
- Implement a laptop backup application.
- Implement Phase II of the NERC public website upgrade.
- Enhance or replace applications supporting key business processes.

## Overview of Funding Requirements

Now in the third year of the three-year plan first set forth in 2011, ~~the company~~NERC's 2013 Business Plan and Budget reflects the resources required for NERC to continue to deliver on its mission. NERC's 2013 Business Plan and Budget also reflects the ongoing efforts of NERC to better define program area requirements and allocate resources in order to make more meaningful and demonstrable contributions to improvements in the reliability of the bulk power systems in North America. NERC has enhanced the depth of information provided in its 2013 Business Plan and Budget to improve transparency by providing significantly more detail regarding departmental activities and costs, including the relationship of these activities ~~in~~to furthering the goals of section 215 of the Federal Power Act.

NERC's 2012 Business Plan and Budget presented a three-year budget forecast which reflected a leveling off of incremental resource needs in 2013. NERC's 2013 budget forecast is consistent with this previously forecasted trend and NERC anticipates this trend to continue through 2015 absent major unanticipated events.

The following sections of the 2013 Business Plan and Budget describe in detail the resources needed in 2013 for NERC to continue to carry out its mission. The 2013 funding requirements reflect the costs of ongoing operations, including but not limited to personnel costs based on projected 2012 year-end headcount, contracts for office space, software licensing, third party data management, communication and other services to support operations, including the operation and maintenance of infrastructure investments. Incremental funding requirements in 2013 are primarily driven by resources required to fund investments in additional technology

and applications to facilitate improved business processes, as well as resource additions to support standards development, Regional Entity oversight, reliability risk assessment and training and education initiatives. The 2013 funding requirements for these items are partially offset by savings realized from the completion, elimination, or reduction in the scope of various other program area initiatives, as well as savings associated with reduction in costs of personnel costs, including significant savings resulting from changes to employee benefit and retirement programs.

NERC is projecting an overall 2013 increase of approximately $~~933k~~ 781k in total operating expenses and capital expenditures, which is approximately 1.5~~8~~ percent over 2012 and represents NERC's lowest year-over-year budget increase since becoming the ERO. Total 2013 projected operating expenses and capital expenditures are approximately $1.4~~2~~M (2.6~~2~~ percent) less than the 2013 projection contained in NERC's 2012 Business Plan and Budget.

Penalty funds received in 2012 will reduce NERC's 2013 assessments funding to approximately $1.7~~5~~M (~~2.9~~3.5 percent) below NERC's 2012 assessments. ~~The second draft of NERC's 2013 Business Plan and Budget will set forth the proposed assessments for United States, Canadian and Mexican entities a~~After taking into account the application of NERC's policies regarding the allocation of United States penalty funds[15], ~~and~~the allocation of certain compliance and enforcement cost~~s.~~[16], and using 2010 net energy for load data, assessments will be approximately $1.9M (4.1%) lower for United States entities, $109.9k (2.5%) higher for Canadian entities, and $4.2k (3.6%) higher for Mexican entities.

NERC is not proposing to increase working capital in 2013 and will instead rely on its 2012 year end working capital reserve balance to satisfy 2013 working capital and contingency operating reserve needs. Under the leadership of the Finance and Audit Committee, management has also developed and ~~will be presenting~~and presented a proposed working capital policy and contingency operating reserve guidelines at the May 8, 2012 Finance and Audit Committee meeting. This proposed policy and guidelines are discussed further on page ~~21~~ and has been updated to reflect feedback from the Finance and Audit Committee~~.~~

~~NERC management is also in the process of developing preliminary budget projections for 2014 and 2015. These projections will be included in the second draft of NERC's 2013 Business Plan and Budget, which is scheduled to be posted and publicly available on May 25, 2012. In the absence of unforeseen developments, management anticipates that the projected budget for 2014 and 2015 will be flat or remain in the low single digits.~~

Management has prepared preliminary budget projections for 2014 and 2015. These projections reflect close to a 0 percent increase in 2015 and a nominal 2.1% increase in 2015. These projections are preliminary and subject to change. Further information regarding the assumptions underlying these projections may be found on page .

15 Accounting, Financial Statement and Budgetary Treatment of Penalties Imposed and Received for Violations of Reliability Standards, December 8, 2008

16 Expanded Policy on allocation of Certain Compliance and Enforcement Costs, July 29, 2008

## Cost of Current Operations and Additional Resource Requirements

Building on previous business planning initiatives, including feedback from the Board and stakeholders, the first step NERC took in preparing its 2013 budget was to undertake a comprehensive review of existing resource allocation to ensure alignment with the ERO's strategic goals and objectives. Departmental staffing, consulting, and contractor costs were also thoroughly reviewed, as were travel and meeting expenses and other operating costs. During 2011, NERC management implemented a new employee performance management program to better align individual and departmental performance with corporate goals and objectives. This process, which has now been institutionalized, also provided and will continue to provide an opportunity for management to evaluate and address weaknesses in existing resource capabilities. In early 2012, management implemented a new time reporting system which tracks all employee time and includes the ability to track time by function, major activities and project. This capability will be utilized as a tool to both understand and evaluate resource utilization and make more informed decisions regarding future resource allocation and resources needs. Management is also continuing to review and will be implementing further improvements in operating practices and expense controls in order to achieve additional operating efficiencies.

After completing a comprehensive review of existing staffing, management reviewed the costs associated with existing operations, including opportunities to reduce contractor, consulting and other operating expenses. Similar to the budget presentation format used in 2011 and 2012 the costs associated with NERC's existing operations are referred to as NERC's "base operating budget". The base operating budget excludes funding requirements for working capital reserves.[17] The 2013 base operating budget is approximately $49.5M or approximately $3.~~6M~~ 7M less than NERC's approved 2012 budget. This reduction is primarily due to savings in two areas, personnel costs and contractor and consulting expenses. Reductions in personnel costs are primarily the result of lower projected salary ($930K), benefit ($503k) and retirement ($727k) expense. Reductions in contractor and consulting expense ($1.8~~6~~M) are primarily the result of the termination of the Interchange Distribution Calculator ("IDC") contract[18], ~~and transition of the IDC funding to IDC users~~, together with completion of work under existing contracts.

NERC's total projected 2013 budget is approximately $53.9~~4.1~~M which, as previously indicated, represents an increase of approximately $~~933k~~ 781k or 1.5~~8~~ percent over the company's 2012 budget. The company's 2013 budget for personnel expense is approximately $1.6~~1~~M lower than 2012. This reduction is inclusive of the costs of proposed personnel additions in 2013. The 2013 contract and consulting budget is approximately $280~~35~~k higher than 2012. Additional

[17] At this time and as further described herein, based on its 2012 Q1 year-end forecast, NERC is not anticipating increasing funding for working capital reserves in 2013 and will rely on 2012 year end working capital reserves. This assumption will be subject to ongoing review during the budget finalization process as NERC further updates its year-end working capital forecast.

[18] While NERC's budget will be reduced in 2013 as a result of the termination of the IDC contract, IDC costs will continue to be allocated to LSEs in the Eastern Interconnection for at least the balance of 2013 pursuant to the terms of an interim billing services agreement between NERC and an IDC uses group, as further described on page ___.

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detail regarding the contract and consulting costs by department is provided below, as well as in Section A and Exhibit B.

The 2013 budget includes increased rent expense of $2136k, reflecting the amortization of the lease costs for NERC office space over the term of the leases, and a $150k increase in professional services for outside legal support in connection with the five-year performance assessment of NERC. The 2013 budget also includes a $1.04M increase in capital expenditures for IT infrastructure, which is discussed further below and in Section A under Administrative Services.

The cumulative effect of the increase in the cost of current operations, together with proposed incremental 2013 resource additions, is presented in the table below followed summary of the proposed additional resource requirements by department.

| A | | B | C | = B + C | |
|---|---|---|---|---|---|
| 2012 Base Operating Budget | | 2013 Projected Change in Base Operating Budget | Projected inc(dec) in Staffing and Programs | Total Projected Increase 2013 v 2012 Budget | Total Projected 2013 Budget |
| $ 24,800,833 | Salaries | $ (1,194,513) | $ 866,662 | $ (327,851) | 24,472,982 |
| 1,524,935 | Payroll Taxes | (87,027) | 63,484 | (23,543) | 1,501,392 |
| 3,190,308 | Benefits | (490,875) | 115,911 | (374,964) | 2,815,344 |
| 3,489,736 | Retirement | (896,602) | 54,417 | (842,185) | 2,647,551 |
| **$ 33,005,812** | **Total Personnel Expense** | **$ (2,669,017)** | **# $ 1,100,474** | **$ (1,568,543)** | **-4.8% $ 31,437,269** |
| $ 736,000 | Meetings | $ 291,000 | $ - | $ 291,000 | 1,027,000 |
| 2,787,870 | Travel | (124,370) | 75,000 | (49,370) | 2,738,500 |
| 348,910 | Conference Calls | - | - | - | 348,910 |
| **$ 3,872,780** | **Total Meeting Expense** | **$ 166,630** | **# $ 75,000** | **$ 241,630** | **6.2% $ 4,114,410** |
| $ 6,368,000 | Consultants and Contracts | $ (642,666) | $ 2,084,500 | $ 1,441,834 | 7,809,834 |
| 300,094 | NERCnet Contract | - | | - | 300,094 |
| 1,619,220 | IDC Contract | (1,161,634) | | (1,161,634) | 457,586 |
| **$ 8,287,314** | **Contracts and Consultants** | **$ (1,804,300)** | **# $ 2,084,500** | **$ 280,200** | **3.4% $ 8,567,514** |
| $ 2,304,257 | Office Rent | $ 212,557 | $ - | $ 212,557 | 2,516,814 |
| 2,838,819 | Office Costs | 342,696 | | 342,696 | 3,181,515 |
| 2,005,000 | Professional Services | 127,710 | 150,000 | 277,710 | 2,282,710 |
| 26,200 | Miscellaneous | (5,200) | | (5,200) | 21,000 |
| **$ 7,174,276** | **Operating Expenses** | **$ 677,763** | **# $ 150,000** | **$ 827,763** | **11.5% $ 8,002,039** |
| **$ -** | **Non-Operating Expenses** | **-** | | **$ -** | **$ -** |
| $ 772,090 | Computer & Software CapEx | $ - | $ 784,010 | $ 784,010 | 1,556,100 |
| - | Network Equipment | - | 216,000 | 216,000 | 216,000 |
| | Furniture & Fixtures | | | - | - |
| **$ 772,090** | **Capital Expenditures** | **$ -** | **# $ 1,000,010** | **$ 1,000,010** | **129.5% $ 1,772,100** |
| **$ 53,112,272** | **Total Base Operating Budget** | **$ (3,628,924)** | **# $ 4,409,984** | **$ 781,060** | **1.5% $ 53,893,332** |

The following is a brief summary of 2013 additional personnel, contractor and consulting needs, ~~if any,~~ by department. More detailed information ~~is provided~~ by department is provided in Section A.

- **Standards** — The standards department is proposing to add three (3) positions in 2013, including two (2) standards development advisors and one (1) technical writer. The standards development advisors will allow the department to increase the number of concurrent projects that can be processed. The technical writer will help improve

standards quality, which should also improve compliance outcomes and efficiency. No contractors or consultants have been specifically budgeted in the standards area for 2013.[19] $150k has been added to the contractor and consulting budget for additional resources to support the Standards Process Improvement Initiative.

- **Compliance Operations, Organization Registration and Registration** — No additional personnel needs are projected[20]. Consulting support will be required for auditor training and Regional Entity audit oversight. Consulting resources to support training are budgeted under the Training, Education and Operator Certification Program. $120K in consulting resource to support Regional Entity audit oversight are budgeted as part of the consulting support for ~~the company's~~NERC's ~~recently initiated~~ risk management and internal controls framework described further under Administrative Services. This is consistent with the 2012 budget.
- **Enforcement** — No additional personnel needs are projected. Resources required for developing improved data management and analysis systems are budgeted under IT in Administrative Services.
- **Reliability Assessment and Performance Analysis (RAPA)** — One (1) position was added in 2012 to support the development of risk control strategies. One (1) position is proposed to be added in 2013 to provide additional engineering support required to evaluate and prioritize risks and support standards development. $685~~743~~k in consulting support has been budgeted to support RAPA initiatives in 2013, a $313~~255~~k decrease from RAPA's 2012 budget. The contractor and consulting funding includes software licensing and maintenance fees for the generator, transmission, demand side, spare equipment, and other databases, as well as contractor support for special reliability assessments. A more detailed explanation of contractor and consulting support costs is provided under the Reliability Assessment and Performance Analysis discussion in Section A. Additional specialized consulting support may be required to support the Bulk Electric System exception process. These additional resources will be included as part of the projected contingency operating reserve component of working capital and contingency operating reserve guidelines.
- **Training, Education, and Operator Certification** — One (1) position is proposed to be added to provide administrative support, the cost of which will be paid for through operator certification and testing fees and will not impact assessments. Approximately $850~~900~~k in contractor and consulting support is included in the 2013 budget to support training, education and operator certification, representing an increase of approximately $253~~304~~k over 2012 budgeted levels. A significant portion of this increase ($250k) is to fund improvements in the system operator certification and continuing education database. Working capital additions resulting from user fees received for operator training and certification programs exceeding 2011 ~~and 2012~~

[19] A provision for contractor support to assist the standards program area in compliance with regulatory directives will likely be included in the contingency operating reserves as part of the company's proposed working capital and contingency reserve guidelines discussed on page __. Contingency reserve amounts will be presented in the next draft of NERC's business plan and budget.

[20] However, additional CIP auditors will be added to the Critical Infrastructure Department to support oversight of regional entity CMEP activities.

program area costs will be used to fund this database upgrade. This funding approach is consistent with the Rules of Procedure and is further discussed in the ~~company's~~ proposed working capital and contingency operating reserve guidelines.

- **Event Analysis and Investigations** — One (1) position was added in 2012 to support technical writing needs. $120k is budgeted for outside contractor and consulting support of significant events, like the ~~southwest~~ 2011 Southwest outage. This is consistent with the amount included in the 2012 budget.
- **Situation Awareness —** No additional personnel are proposed in 2013. Approximately $2.4M is budgeted for consultants and contractors, including $1.7M in funding for contracts support NASPI, various software tools used to monitor or evaluate reliability or events, software and services support for NERC's secure alert system and costs to support the operation and maintenance of SAFNR. $460K is budgeted to support the IDC prior to termination and the transition of that contract to IDC users. The Situation Awareness budget also includes approximately $300k for NERC's share of a third party secure communications network used to support NERC's situation awareness function. Total 2013 contractor and consulting support for the Situation Awareness department is approximately $1.1M less than in the 2012 budget, primarily due to elimination of IDC contract costs when the contract expires on March 31, 2012.
- **Critical Infrastructure Protection** — Two (2) positions are proposed in 2013 to support Regional Entity audit oversight and one (1) position is proposed to provide additional support for the ES-~~-~~ISAC. $785~~845~~k is budgeted in 2013 for consulting and contractors to support CIP department activities, which is a $10~~50~~k ~~increase over~~decrease from 2012.[21] Contractor and consulting support services are to assist in the preparation of a cyber risk preparedness assessment, to provide continued support for the Electricity Sub-sector Coordinating Council (ESCC), and to plan and conduct a grid security exercise similar to the exercise (Grid-X) which was successfully conducted in 2011. Contractor and consulting support is also included for the build out and operation of the ES-ISAC, including secure portal services and communications, cyber incident analysis, threat modeling, information reporting, ~~web x,~~ and other services more fully described in Section A under ES-ISAC.
- **Administrative Services** — One (1) position is proposed to be added in 2013 to support SharePoint applications development and administration. One (1) position was added to the Finance and Accounting area to provide facilities management. These two additions are offset by a reduction in other positions budgeted in the administrative services area, one of which is a retiring executive and a reduction of one (1) position supporting the Human Resources area. In addition, four (4) staff transferred from other program areas to provide IT project management and administrative and internal controls support as further described ~~under~~in the Administrative Services below. Approximately $2.7M is budgeted in 2013 for contractors and consultants to support various IT infrastructure

[21] Note to reader- this reduction is primarily due to the reclassification of a software expenses from contractors and consultant to Office Costs.

and applications needs, representing an increase of approximately $1.3M over 2012. These contractor and consulting resources will:

- Support major improvements to NERC's website;
- Conduct security vulnerability testing;
- Provide design and integration services; support applications development including improvement in the compliance data base and standards balloting applications;
- Provide project management, support and maintenance services;
- Conduct quality assurance testing;
- Provide data warehouse and common technology platform design;
- Review existing applications and scope solutions to business needs; and
- Provide disaster recovery and electronic file backup services.

An additional amount of approximately $288k is budgeted for contractors and consultants to support various Human Resources needs including staff training, compensation consulting, employee, industry and Board surveys and automated employee support services, including benefits enrollment and employee self-service automation. The contractor and consulting budget for Human Resources is in line with 2012 budgeted amounts. The final component of contractor and consulting support in the Administrative Services area is for NERC's Canadian affairs representative and is consistent with 2012 budgeted levels. Additional detail regarding contractor and consulting support for the Administrative Service area is provided under Administrative Services in Section A. Outside legal services are budgeted under professional services and have been increased $150k over the 2012 budget level to provide funding for additional legal support in connection with NERC's five-year performance assessment.

~~In an effort t~~To further improve the transparency and openness of NERC's business plan and budgeting process as compared to previous years, a detailed spreadsheet with a listing of proposed 2013 contract and consulting costs by department, as well as a comparison to 2012 budgeted amounts, is included in Exhibit B.

## Working Capital and Contingency Operating Reserves

Management has been working with the Finance and Audit Committee of the Board of Trustees to develop a working capital policy and guidelines applicable to the use of ~~contingency~~operating reserves which are not required to satisfy cash flow requirements or for categories of expenditures that are not included as part of the company's approved annual budget but become necessary during the course of the year. An intial draft of management's proposal was posted on NERC's website and presented at the May 8, 2012 Finance and Audit Committee meeting. Based on feedback from the Finance and Audit Committee management has revised it's the proposed Working Capital and Operating Reserve Policy. The changes included:

- Elimination of redundancies and excess wording;

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- Separation of the concept of working capital from operating reserves, since they are different;
- Since access to working capital (under the proposed definition) will only be required for temporary cash flow needs and working capital will be budgeted and approved by both the Board of Trustees and FERC, the revised draft gives NERC's Chief Financial and Administrative Officer the authority to access, subject to a requirement that any draws are promptly replenished from available excess cash flow;
- Reserves to meet bank covenants are not drawn on so no authority for access is needed;
- If the cash reserve requirement needed to satisfy a covenant gets reduced the excess funds will be transferred to the operating reserve account and available to fund unforeseen contingencies; and
- Excess funds from budget under runs would be captured as operating reserves and available to fund unforeseen contingencies under the same authorities applicable to other unforeseen contingencies.

The proposed form of the revised Working Capital and Operating Reserve Policy is set forth in Exhibit C, together with proposed 2013 Working Capital and Operating Reserve Amounts.

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~~Management has recommended that the company's working capital requirements include four components or categories: (1) an amount necessary to satisfy projected cash flow and cash balance requirements, (2) an amount necessary to satisfy known contingencies where the specific timing and amount is uncertain, (3) an amount available to be utilized for unforeseen contingency and (4) excess funds applicable to the Personnel Certification and Operator Training Program. Each of these categories will be separately identified and quantified each year in the business plan and budget submitted to the Board of Trustees and FERC for approval. Each category is described further below. These recommendations, together with proposed guidelines and authorities for accessing working capital and operating reserves, will be the subject of further review and the May 8, 2012 meeting or the Finance and Audit Committee.~~

~~**(1) Projected Cash Flow and Cash Balance Requirements**~~

~~Management has recommended that a certain funds be set aside for purposes of satisfying cash flow and cash balance requirements set forth and approved annually as part of the company's business plan and budget. Annual cash flow and cash balance requirements would be determined based on a review of (a) projected cash flow needs over the budget year and (b) cash balances required to satisfying applicable covenants or other obligations contained in any loan or other agreement to which the company is a party.~~

~~**(2) Known Contingencies Where the Amount and Timing Are Uncertain**~~

~~Management also recommended that an operating reserve be created to provide funding for known contingencies specifically set forth in the business plan and budget but where the timing and amount of funding to satisfy the contingency when it materializes is uncertain. An example would be the need for additional resources to address a requirement or process where regulatory or other governmental authorizations or directives are pending or anticipated but an order has not yet been~~

~~issued so the amount of the impact and timing is uncertain but management has nevertheless concluded that additional resources are likely to be required. The projected resources or range of resources associated with such contingencies would be set forth and approved as part of the annual business plan and budget, providing opportunity for stakeholder review and comment on identified contingencies.~~

~~**(3) Unforeseen Contingencies**~~

~~Management further recommended that an operating reserve be created to fund known unknown contingencies which were not anticipated at the time of preparation and approval of the business plan and budget. Examples of unforeseen contingencies might include supplemental resources required to assist in the evaluation of significant events affecting the bulk electric system such as the February cold weather event and southwest outage. The need for funding for unforeseen contingencies has also previously arisen in connection with unforeseen regulatory directives and has been recognized by FERC as an important consideration in the company's determination of its working capital requirements.[22]~~

~~**(4) Excess Funds applicable to the Personnel Certification and Operator Training Program**~~

~~Management is also recommending that in the event the company realizes higher levels of funding from operator certification and training above incurred expenses, this excess funding will be added to working capital and set aside and used solely for operator training and certification needs as determined by the company and the Personnel Certification and Governance Committee. This is consistent with the requirements of Section 6.04.4.10 of the Rules of Procedure. Expenditures of these funds would be reported as part of the company's quarterly variance reporting to the finance and audit committee, which reports are also posted on the company's' website and reviewed on conference calls or meetings of the committee which are open to the public.~~

~~Subject to the outcome of the Finance and Audit Committee's review of management's proposed working capital policy and contingency operating reserve guidelines, the next draft of the company's proposed 2013 Business Plan and Budget will include management's recommendations regarding its 2013 proposed working capital budget, including proposed funding amounts for each of the four categories discussed above and inviting stakeholder feedback. The next draft of the business plan and budget is scheduled to be posted on NERC's website on May 25, 2012 and publicly available for review and comment.~~

## 2013 Funding and Assessment Forecast

NERC's 2013 budget results in a $781~~933~~k or 1.5~~8~~ percent increase in operating costs and capital expenditures over NERC's 2012 budget. The chart below provides a breakdown of the

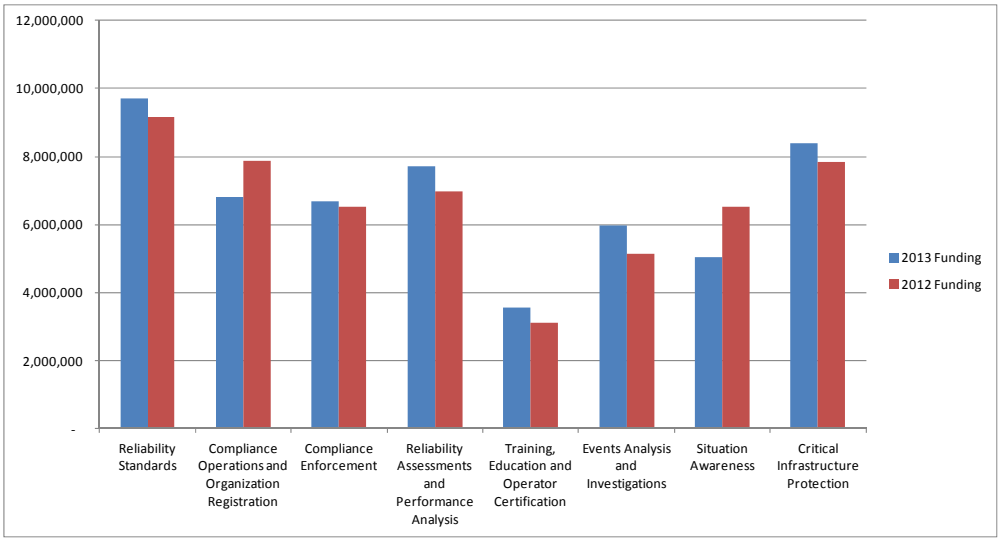
~~[22] 2010 ERO Budget Order (issued Oct. 15, 2009), 129 FERC ¶ 61,040, at P 24: "Working capital reserves provide readily available funds, which are available without a charge for or restriction on their use, to meet unforeseen expenditures. The Commission is concerned about the risks and costs associated with NERC's relying solely on a line of credit and not having available working capital reserves."~~

relative contributions of the cost of current operation, proposed 2013 resource additions and application of penalty funding to produce a $1.765M (3.52.9 percent) reduction in assessments. The chart also reflects a $250k reduction in revenues for third party licensing of GADS software discussed above under Reliability Assessments and Performance Analysis, and a $250k use of working capital to fund an update of the System Operator Certification and Continuing Education Database (SOCCED). Please note that actual assessments for United States, Canadian and Mexican entities will vary after taking into account polices regarding the allocation of certain compliance and enforcement costs. An update to theThe following preliminary calculation of proposed changes in assessments taking reflectsing these policies. will be included in a future draft of NERC's 2013 Business Plan and Budget.

| Increase (Decrease) in 2013 Assessment | | | % of 2012 Assessments |
|---|---|---|---|
| Due to current operations | $ | (3,628,924) | |
| Due to proposed resource additions | | 4,409,984 | |
| Due to Penalty Offset | | (2,412,500) | |
| Due to increased Workshop Fees | | (316,000) | |
| Due to reductions in revenues for GADS software | | 250,000 | |
| Due to reductions in System Operator Testing Fees and Certificate Renewal Fees | | 183,500 | |
| Use of Working Capital - SOCCED Database | | (250,000) | |
| **Total** | **$** | **(1,763,940)** | **-3.5%** |
| **Estimated Decrease for US entities** | | **(1,878,040)** | **-4.7%** |
| **Estimated Increase for Canadian entities** | | **109,876** | **2.5%** |
| **Estimated Increase for Mexico entities** | | **4,224** | **3.6%** |

The following charts and tables show, (1) the breakdown of funding requirements by department, including allocation of administrative services costs (2) relative increases by department, (3) 2012 and 2013 FTEs and headcount by department, and (4) a comparative Statement of Activities.

| Total Budget | Budget 2012 | Budget 2013 | Change 2013 Budget v 2012 Budget | % Change |
|---|---|---|---|---|
| Reliability Standards | 9,156,601 | 9,708,768 | 552,167 | 6.0% |
| Compliance Operations and Organization Registration | 7,860,024 | 6,817,981 | (1,042,043) | -13.3% |
| Compliance Enforcement, Reporting, Tracking and Analysis | 6,528,040 | 6,696,092 | 168,052 | 2.6% |
| Reliability Assessments and Performance Analysis | 6,968,860 | 7,714,046 | 745,186 | 10.7% |
| Training, Education and Operator Certification | 3,098,130 | 3,569,685 | 471,555 | 15.2% |
| Events Analysis and Investigations | 5,126,471 | 5,962,049 | 835,578 | 16.3% |
| Situation Awareness | 6,534,397 | 5,040,387 | (1,494,010) | -22.9% |
| Critical Infrastructure Protection | 7,839,749 | 8,384,323 | 544,574 | 6.9% |
| Total Budget | 53,112,272 | 53,893,332 | 781,060 | 1.5% |



| Total FTE's by Program Area | Budget 2012 | Transfers In(Out) | Projection 2012 | Total FTEs 2013 Budget | Change from 2012 Budget |
|---|---|---|---|---|---|
| **STATUTORY** | | | | | |
| **Operational Programs** | | | | | |
| Reliability Standards | 24.92 | (1.67) | 23.42 | 26.50 | 1.58 |
| Compliance Operations and Organization Registration | 21.66 | (2.66) | 18.73 | 19.00 | (2.66) |
| Compliance Enforcement, Reporting, Tracking and Analysis | 21.00 | | 19.54 | 21.00 | - |
| Events Analysis and Investigations | 13.00 | 1.00 | 14.75 | 15.50 | 2.50 |
| Reliability Assessments and Performance Analysis | 16.50 | 1.00 | 6.72 | 18.75 | 2.25 |
| Training, Education and Operator Certification | 6.75 | | 16.91 | 8.00 | 1.25 |
| Situation Awareness | 8.17 | (1.67) | 6.15 | 6.50 | (1.67) |
| Critical Infrastructure Protection | 17.00 | | 16.42 | 19.25 | 2.25 |
| **Total FTEs Operational Programs** | **129.00** | **(4.00)** | **122.64** | **134.50** | **5.50** |
| **Administrative Programs** | | | | | |
| Technical Committees and Member Forums | - | | - | - | - |
| General & Administrative | 7.00 | 1.00 | 8.00 | 7.00 | - |
| Legal and Regulatory | 13.00 | 1.00 | 13.65 | 14.00 | 1.00 |
| Information Technology | 12.75 | 3.00 | 15.49 | 16.75 | 4.00 |
| Human Resources | 6.00 | (2.00) | 4.00 | 3.00 | (3.00) |
| Finance and Accounting | 9.00 | 1.00 | 10.96 | 11.00 | 2.00 |
| **Total FTEs Administrative Programs** | **47.75** | **4.00** | **52.10** | **51.75** | **4.00** |
| **Total FTEs** | **176.75** | **-** | **174.74** | **186.25** | **9.50** |

**Statement of Activities, Fixed Assets Expenditures and Change in Working Capital**
**2012 Budget & Projection, and 2013 Budget**
**STATUTORY**

| | 2012 Budget | 2012 Projection | Variance 2012 Projection v 2012 Budget Over(Under) | 2013 Budget | Variance 2013 Budget v 2012 Budget Over(Under) | 2013 Budget Draft 1 | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|---|---|
| **Funding** | | | | | | | |
| **ERO Funding** | | | | | | | |
| NERC Assessments | $ 50,661,272 | $ 50,661,271 | $ (1) | $ 48,897,332 | $ (1,763,940) | $ 49,181,546 | $ (284,214) |
| Penalty Sanctions | - | - | - | 2,412,500 | 2,412,500 | 2,412,500 | - |
| **Total NERC Funding** | **$ 50,661,272** | **$ 50,661,271** | **$ (1)** | **$ 51,309,832** | **$ 648,560** | **$ 51,594,046** | **$ (284,214)** |
| Membership Dues | - | - | - | - | - | - | - |
| Testing Fees | 2,061,000 | 2,061,000 | - | 1,877,500 | (183,500) | 2,061,000 | (183,500) |
| Services & Software | 250,000 | 130,060 | (119,940) | - | (250,000) | - | - |
| Workshops | 120,000 | 175,225 | 55,225 | 436,000 | 316,000 | 120,000 | 316,000 |
| Interest | 20,000 | 20,000 | - | 20,000 | - | 20,000 | - |
| Miscellaneous | - | - | - | - | - | - | - |
| **Total Funding (A)** | **$ 53,112,272** | **$ 53,047,556** | **$ (64,716)** | **$ 53,643,332** | **$ 531,060** | **$ 53,795,046** | **$ (151,714)** |
| **Expenses** | | | | | | | |
| **Personnel Expenses** | | | | | | | |
| **Salaries** | $ 24,800,833 | $ 23,491,962 | $ (1,308,871) | $ 24,472,982 | $ (327,851) | $ 24,737,775 | (264,793) |
| **Payroll Taxes** | 1,524,935 | 1,414,721 | (110,214) | 1,501,392 | (23,543) | 1,508,979 | (7,587) |
| **Benefits** | 3,190,308 | 2,467,328 | (722,980) | 2,815,344 | (374,964) | 2,803,059 | 12,285 |
| **Retirement Costs** | 3,489,736 | 2,402,063 | (1,087,673) | 2,647,551 | (842,185) | 2,816,897 | (169,346) |
| **Total Personnel Expenses** | **$ 33,005,812** | **$ 29,776,074** | **$ (3,229,738)** | **$ 31,437,268** | **$ (1,568,544)** | **$ 31,866,710** | **(429,441)** |
| **Meeting Expenses** | | | | | | | |
| **Meetings** | $ 736,000 | $ 780,569 | $ 44,569 | $ 1,027,000 | $ 291,000 | $ 786,000 | 241,000 |
| **Travel** | 2,787,870 | 2,895,120 | 107,250 | 2,738,500 | (49,370) | 2,787,870 | (49,370) |
| **Conference Calls** | 348,910 | 376,310 | 27,400 | 348,910 | - | 348,910 | - |
| **Total Meeting Expenses** | **$ 3,872,780** | **$ 4,051,999** | **$ 179,219** | **$ 4,114,410** | **$ 241,630** | **$ 3,922,780** | **191,630** |
| **Operating Expenses** | | | | | | | |
| **Consultants & Contracts** | $ 8,287,314 | $ 8,800,666 | $ 513,352 | $ 8,567,514 | $ 280,200 | $ 8,522,347 | 45,167 |
| **Office Rent** | 2,304,257 | 2,784,036 | 479,779 | 2,516,814 | 212,557 | 2,520,000 | (3,186) |
| **Office Costs** | 2,838,819 | 3,042,241 | 203,422 | 3,181,515 | 342,696 | 2,838,819 | 342,696 |
| **Professional Services** | 2,005,000 | 2,621,290 | 616,290 | 2,282,710 | 277,710 | 2,155,000 | 127,710 |
| **Miscellaneous** | 26,200 | 25,309 | (891) | 21,000 | (5,200) | 26,200 | (5,200) |
| **Depreciation** | 1,900,717 | 1,592,217 | (308,500) | 1,579,801 | (320,916) | 1,900,717 | (320,916) |
| **Total Operating Expenses** | **$ 17,362,307** | **$ 18,865,760** | **$ 1,503,453** | **$ 18,149,354** | **$ 787,047** | **$ 17,963,083** | **$ 186,271** |
| **Total Direct Expenses** | **$ 54,240,899** | **$ 52,693,832** | **$ (1,547,067)** | **$ 53,701,033** | **$ (539,866)** | **$ 53,752,573** | **$ (51,540)** |
| **Indirect Expenses** | **$ -** | **$ (0)** | **$ (0)** | **$ -** | **$ -** | **$ (0)** | **$ 0** |
| **Other Non-Operating Expenses** | **$ -** | **$ 60,955** | **$ 60,955** | **$ -** | **$ -** | **$ -** | **$ -** |
| **Total Expenses (B)** | **$ 54,240,899** | **$ 52,754,787** | **$ (1,486,112)** | **$ 53,701,033** | **$ (539,866)** | **$ 53,752,573** | **$ (51,540)** |
| **Change in Assets** | **$ (1,128,627)** | **$ 292,769** | **$ 1,421,396** | **$ (57,701)** | **$ 1,070,926** | **$ 42,473** | **(100,174)** |
| **Fixed Assets** | | | | | | | |
| Depreciation | $ (1,900,717) | $ (1,592,217) | $ 308,500 | $ (1,579,801) | $ 320,916 | $ (1,900,717) | $ 320,916 |
| Computer & Software CapEx | 772,090 | 825,316 | 53,226 | 1,556,100 | 784,010 | 1,952,190 | (396,090) |
| Furniture & Fixtures CapEx | - | 212 | 212 | - | - | - | - |
| Equipment CapEx | - | 32,293 | 32,293 | 216,000 | 216,000 | 241,000 | (25,000) |
| Leasehold Improvements | - | 47,841 | 47,841 | - | - | - | - |
| Allocation of Fixed Assets | **$ -** | $ 0 | $ 0 | $ - | $ - | **$ (0)** | **$ 0** |
| **Inc(Dec) in Fixed Assets ( C )** | **(1,128,627)** | **(686,555)** | **442,072** | **192,299** | **1,320,926** | **292,473** | **-** |
| **TOTAL BUDGET (=B + C)** | **$ 53,112,272** | **$ 52,068,232** | **$ (1,044,040)** | **$ 53,893,332** | **$ 781,060** | **$ 54,045,046** | $ (151,714) |
| **TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)** | **$ -** | **$ 979,324** | **$ 979,324** | **$ (250,000)** | **$ (250,000)** | **$ (250,000)** | **$ (0)** |
| **FTEs** | 176.75 | 174.61 | (2.14) | 186.25 | 9.5 | 186.25 | - |

## Summary of Variances by Category – 2013 Budget Compared to the 2012 Budget

- Personnel Expenses – Total Personnel Expenses are projected to decrease approximately $1.6M from 2012. Salary and Payroll Tax expenses are projected to be

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lower in 2013 than in 2012 even though 9.5 FTEs are being added due to lower average costs per FTE. As reflected in Table B-4 on page XX, the average cost per FTE for salary and payroll tax expense are projected to be $131,399 and $8,061 respectively in 2013, which is less than the average costs in the 2012 budget by $8,917 and $566 respectively. As previously indicated, changes to NERC's employee benefit and retirement plans also resulted in lower average costs per FTE in 2013. The average cost per FTE for employee benefit plans is projected to be $2,934 lower and the average cost per FTE for retirement plans is projected to be $5,529 lower in 2013 compared to the 2012 budget. In total, the average total personnel costs per FTE are projected to be $17,947 lower in 2013 compared to the 2012 budget.

- Meetings, Travel and Conference Calls – Meetings expenses include the cost of catering, audio visual and meeting rooms for all meetings and workshops sponsored by NERC. Meetings expense does not include NERC employees' travel to attend the meeting. All business travel is recorded as Travel Expense. The 2013 budget for Meetings Expense is $291k higher than 2012 primarily due to an increase in the number of workshops and by the number of attendees. The increase in Workshop expenses is offset by higher funding from Workshop fees.
- Operating Expenses
  - Consultants & Contracts – A detailed listing of all Contracts and Consulting projects is included in Exhibit B and is further detailed in each Program in Section A
  - Office Rent – Increased cost of NERC's Atlanta and new DC offices
  - Office Costs – Primarily related to higher maintenance and service agreements for network equipment, computers and software ~~licensces~~licenses.
  - Professional Services - $150k related to the five-year performance assessment of NERC.
- Miscellaneous Expenses – NERC is not planning or budgeting for a year-end holiday party in 2013. NERC may have year-end employee meetings and the associated expenses will be recorded as meeting~~s~~ and/or travel expenses, as applicable ~~as~~ and described above.
- Fixed Assets – As further detailed in Section A under Information Technology, the variance is for planned investments in infrastructure for a centralized data repository and for disaster recovery.

Projections for 2014-2015

The 2014 Budget is projected to be approximately $183k (0.3%) less than the 2013 Budget. The 2015 Budget is projected to be approximately $1.1M (2.1%) higher than the 2014 Budget.

2014 Assumptions

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- Personnel – Increases $2.1M due to salary increases, increased benefits costs and 6.0 new positions (3.75) FTEs – 2.0 Standards Development Advisors and 1.0 Technical Writer; 1.0 Risk Control Strategy and Standards Coordinator in RAPA; 1.0 Reliability Engineer in Events Analysis and Investigations; and 1.0 SharePoint Developer in IT. The remaining 1.75 FTEs is the effect of 2013 new hires being on staff for the full year.
- Consultants and Contracts – Decreases $2.3M
    - Situation Awareness decreases $1.3M due to elimination of IDC contract ($457k) and completion of NASPI contract ($810k)
    - RAPA decreases $245k – RADS Assessment Database development completed in 2013 and reduction in contract support to study the reliability affects of GMD
    - CIP decreases $135k - A grid security exercise is not planned for 2014 ($200k), offset by increases in ESCC support and Cyber Risk Preparedness Assessments.
    - IT decreases approximately $620k due to projected lower funding requirements for multiple projects.

2015 Assumptions

No additional personnel ~~to be~~were included in the projection since ~~added~~it was not possible to predict incremental resource needs for 2015 with any degree of accuracy and at this point are assumed to be primarily driven by unanticipated external factors and efforts to improve the efficiency of current operations and resource utilization. Budgeted ~~S~~salary adjustments and projected increases in benefits costs add approximately 3% ($1.0M) to the total budget.

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**Statement of Activities, Fixed Assets Expenditures and Change in Working Capital**
**2012 Budget & Projection, and 2013 Budget**
**2012 Budget & Projected 2013 and 2014 Budgets**

| | 2013 Budget | 2014 Projection | $ Change 14 v 13 | % Change 14 v 13 | 2015 Projection | $ Change 15 v 14 | % Change 15 v 14 |
|---|---|---|---|---|---|---|---|
| **Funding** | | | | | | | |
| **ERO Funding** | | | | | | | |
| NERC Assessments | $ 48,897,332 | $ 51,092,073 | $ 2,194,741 | 4.49% | $ 52,095,927 | $ 1,003,854 | 1.9% |
| Penalty Sanctions | 2,412,500 | | (2,412,500) | -100.00% | | - | |
| **Total NERC Funding** | **$ 51,309,832** | **$ 51,092,073** | **$ (217,759)** | **-0.4%** | **$ 52,095,927** | **$ 1,003,854** | **1.9%** |
| Membership Dues | - | | - | | | - | |
| Testing Fees | 1,877,500 | 1,862,500 | (15,000) | -0.80% | 1,847,500 | (15,000) | -0.8% |
| Services & Software | - | | - | | | - | |
| Workshops | 436,000 | 436,000 | - | 0.00% | 436,000 | - | 0.0% |
| Interest | 20,000 | 20,000 | - | 0.00% | 20,000 | - | 0.0% |
| Miscellaneous | - | | - | | | - | |
| **Total Funding (A)** | **$ 53,643,332** | **$ 53,410,573** | **$ (232,759)** | **-0.4%** | **$ 54,399,427** | **$ 988,854** | **1.9%** |
| **Expenses** | | | | | | | |
| **Personnel Expenses** | | | | | | | |
| **Salaries** | $ 24,472,982 | $ 25,759,734 | $ 1,286,752 | 5.3% | $ 26,609,778 | $ 850,044 | 3.3% |
| **Payroll Taxes** | 1,501,392 | 1,584,261 | 82,869 | 5.5% | 1,617,278 | 33,017 | 2.1% |
| **Benefits** | 2,815,344 | 3,234,766 | 419,422 | 14.9% | 3,512,581 | 277,815 | 8.6% |
| **Retirement Costs** | 2,647,551 | 2,932,177 | 284,626 | 10.8% | 2,775,410 | (156,767) | -5.3% |
| **Total Personnel Expenses** | **$ 31,437,268** | **$ 33,510,938** | **$ 2,073,670** | **6.6%** | **$ 34,515,047** | **$ 1,004,109** | **3.0%** |
| **Meeting Expenses** | | | | | | | |
| **Meetings** | $ 1,027,000 | $ 1,027,000 | $ - | 0.0% | $ 1,027,000 | - | 0.0% |
| **Travel** | 2,738,500 | 2,688,500 | (50,000) | -1.8% | 2,688,500 | - | 0.0% |
| **Conference Calls** | 348,910 | 348,910 | - | 0.0% | 348,910 | - | 0.0% |
| **Total Meeting Expenses** | **$ 4,114,410** | **$ 4,064,410** | **$ (50,000)** | **-1.2%** | **$ 4,064,410** | **$ -** | **0.0%** |
| **Operating Expenses** | | | | | | | |
| **Consultants & Contracts** | $ 8,567,514 | $ 6,305,818 | (2,261,696) | -26.4% | $ 6,213,067 | (92,751) | -1.5% |
| **Office Rent** | 2,516,814 | 2,496,238 | (20,577) | -0.8% | 2,496,238 | - | 0.0% |
| **Office Costs** | 3,181,515 | 3,307,791 | 126,276 | 4.0% | 3,235,287 | (72,504) | -2.2% |
| **Professional Services** | 2,282,710 | 2,182,278 | (100,432) | -4.4% | 2,182,278 | - | 0.0% |
| **Miscellaneous** | 21,000 | 21,000 | - | 0.0% | 21,000 | - | 0.0% |
| **Depreciation** | 1,579,801 | 1,696,930 | 117,129 | 7.4% | 1,969,314 | 272,384 | 16.1% |
| **Total Operating Expenses** | **$ 18,149,354** | **$ 16,010,055** | **$ (2,139,300)** | **-11.8%** | **$ 16,117,184** | **$ 107,129** | **0.7%** |
| **Total Direct Expenses** | **$ 53,701,033** | **$ 53,585,403** | **$ (115,630)** | **-0.2%** | **$ 54,696,641** | **$ 1,111,238** | **2.1%** |
| **Indirect Expenses** | **$ -** | **$ -** | | | **$ -** | **$ -** | |
| **Other Non-Operating Expenses** | **$ -** | | **$ -** | | | **-** | |
| **Total Expenses (B)** | **$ 53,701,033** | **$ 53,585,403** | **$ (115,630)** | **-0.2%** | **$ 54,696,641** | **1,111,238** | **2.1%** |
| **Change in Assets** | **$ (57,701)** | **$ (174,830)** | **$ (117,129)** | **203.0%** | **$ (297,214)** | **$ (122,384)** | **70.0%** |
| **Fixed Assets** | | | | | - | | |
| Depreciation | $ (1,579,801) | $ (1,696,930) | $ (117,129) | 7.4% | $ (1,969,314) | $ (272,384) | 16.1% |
| Computer & Software CapEx | 1,556,100 | 1,556,100 | - | 0.0% | 1,556,100 | - | 0.0% |
| Furniture & Fixtures CapEx | - | - | - | | - | - | |
| Equipment CapEx | 216,000 | 216,000 | - | 0.0% | 216,000 | - | 0.0% |
| Leasehold Improvements | - | | - | | | - | |
| Allocation of Fixed Assets | | | | | | | |
| **Inc(Dec) in Fixed Assets ( C )** | **$ 192,299** | **$ 75,170** | **$ (117,129)** | **-60.9%** | **$ (197,214)** | **$ (122,384)** | **0.0%** |
| **TOTAL BUDGET (=B + C)** | **$ 53,893,332** | **$ 53,660,573** | **$ (232,759)** | **-0.4%** | **$ 54,499,427** | **$ 1,111,238** | **2.1%** |
| **TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)** | **$ (250,000)** | **$ (250,000)** | **$ -** | **0.0%** | **$ (100,000)** | **150,000** | **-60.0%** |
| **FTEs** | 186.25 | 191.75 | | | 194.00 | | |

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# Section A — 2013 Business Plan and Budget

## Reliability Standards

| Reliability Standards Program (in whole dollars) | 2012 Budget | 2013 Budget | Increase (Decrease) | 2013 Budget - Prior Draft | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|
| Total FTEs | 24.92 | 26.50 | 1.58 | 26.5 | - |
| Direct Expenses | $ 5,307,943 | $ 5,246,971 | $ (60,972) | $ 5,141,915 | $ 105,056 |
| Indirect Expenses | $ 4,011,842 | $ 4,403,127 | $ 391,285 | $ 4,375,208 | $ 27,919 |
| Other Non-Operating Expenses | $ - | $ - | $ - | | $ - |
| Inc(Dec) in Fixed Assets | $ (163,184) | $ 58,669 | $ 221,853 | $ 113,560 | $ (54,891) |
| Total Funding Requirement | $ 9,156,602 | $ 9,708,768 | $ 552,166 | $ 9,630,683 | $ 78,085 |

### Background and Scope

NERC's Reliability Standards Program develops and maintains standards designed to ensure the reliability of the bulk power system in North America. NERC's ANSI-accredited standards development process was reaccredited in 2011 and found to be open, balanced, and transparent. The process is very labor intensive with respect to the NERC and Regional staff and the industry technical experts upon which it relies heavily. Industry technical experts scope, draft, review and ultimately approve through a multi-cycle balloting and commenting process, the new or revised NERC reliability standards for adoption by NERC's Board of Trustees and filing with regulatory authorities in the United States and Canada.

NERC standard development advisors, coordinators and other standards staff facilitate standards drafting team activities, assist the drafting teams in maintaining adherence to the development process, and ensure that the quality of documents produced are appropriate for approval by industry and the NERC Board of Trustees. Each standard must be technically excellent, just, reasonable, not unduly discriminatory or preferential, in the public interest, and developed in adherence ~~with~~to the approved process in order to be adopted by the United States and Canadian regulatory authorities. NERC manages the work of over 200 industry contributors serving on standards drafting, interpretation and other project teams for the development of NERC standards through its standards development program. ~~This is not to mention the~~Additionally, hundreds of industry volunteers within registered entities and other entities who review and comment on the products of these teams. There are over 900 registered balloters in the NERC ballot body. ~~Each~~Most of these balloters ha~~s~~ve a team of subject matter experts internal to their organization that they confer with to establish their positions (comments and ballots) on a given standards program work product. Within the Regions many Regional Organizations organize and collaborate with their respective Regional Entities to develop regional positions also.

~~For North American standards, t~~The Standards Committee (one of NERC's standing committees) provides process oversight, ongoing prioritization and re-prioritization of work, resolves disputes regarding fidelity to process and verifies that the standards development process has been faithfully executed, ensuring the quality of the work product. The Standards Committee is ~~also~~currently responsible for the development and implementation of the required three-year Reliability Standards Development Plan ~~(RDSP)~~ used to establish priorities for standards development, respond to regulatory directives, and guide standard development activities. The NERC Standards staff supports the operational requirements of the Standards Committee and all standards drafting teams. In conjunction with legal staff the NERC standards staff and members of drafting teams provide further support in the preparation of materials for submission to the regulatory authorities in the United States and Canada for approval of the standards work products. These efforts are not solely limited to the standards themselves and glossary terms, but include also the associated compliance elements, subsequent responses to Notices of Proposed Rulemaking or other related issuances, and interpretations of standards. ~~which are not limited to standards, but include also interpretations of standards, glossary terms, and compliance elements, such as Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs)~~.

The standards program also provides the eight Regional Entities with the mechanism to process regional standards when reliability gaps are detected at the regional level. The NERC standards staff supports each of the eight Regional Standards Development Processes by providing such services as technical advice, final quality review of regional standards, presentation to the NERC Board of Trustees and preparation of regional standards petition materials for submission to the applicable regulatory authorities in the United States and Canada for adoption.

An extensive regulatory interface capability has evolved through time involving direct engagement with FERC ~~S~~standards ~~S~~staff. ~~(OER) and the resolution of directives.~~ This regulatory interface provides ~~S~~significant resources have been devoted to resolving the historical FERC standards directives. Additionally, projects ~~which~~that may lead to standards modifications, but which are not yet ripe for specific standards drafting team assignment include ~~such~~ examples ~~and~~such as the Order 754 project examining single point of failure ~~which concerned the Commission~~.[23]

Pursuant to the request of the Board of Trustees and operating guidelines from the Standards Committee, NERC standards and other NERC technical staff ~~actively engage in~~ review ~~of~~ both the regional and North America-wide standards development activities ~~to~~and provide technical and development input to the standards development process in order to aid the development of technically sound standards that can receive regulatory approval.

The standards program now has 14 concurrent standards projects plus numerous interpretation requests and other projects under active development. During the first quarter 2012, it became apparent that ~~a large number of~~several significant projects, including CSO706 (Cyber

[23] http://www.nerc.com/files/2012_Directives_Report_complete.pdf

Security), would be ready for posting for 30- and 45-day formal comment and ballot at the same time. Postings for some projects have been held in order ~~T~~to manage this workload for stakeholders and make efficient use of industry reviewer, drafting team and NERC staff resources~~, postings for some projects have been delayed~~.

**Key Standards Production Efforts in 2012**

At the request of the Commission, through its processes and with the tremendous support of the industry, NERC successfully created and ~~timely~~ submitted a proposed new definition of the Bulk Electric System and an accompanying ~~administrative~~exception process to manage it effectively through its Rules of Procedure. The definition will clarify assets and applicability which should help registered entities better fulfill their obligations under the Reliability Standards. Standards modifications in the area of Critical Infrastructure Protection, Real-Time Operations, Disturbance and Sabotage Reporting are ~~a few~~ other high priority efforts for 2012.

Key process-related focus areas in 2012 include~~d~~:

**Standard Process Improvement Initiative**

At the request of the NERC Board of Trustees, the Members Representative Committee formed a Standards Process Input Group (SPIG) and sought industry feedback on ways to improve the quality, timeliness, efficiency and effectiveness of the standards development process, as well as the importance and significance of meeting ANSI requirements. ~~This proposal is calling for significant change in the approach used to decide whether a risk issue should be directed towards standards development as the vehicle for mitigation. At the time of this submittal, the proposal is under consideration by the Board and there will be further detail as direction is given with respect to execution of changes. The key element is the establishment of a Reliability Issues Steering Committee (RISC) which will review risks and decide on the comprehensive approach. It is unlikely the work load in the standards function will decreased as a result.~~ The SPIG developed a proposal[24] calling for significant change in the approach used to plan overall ERO execution strategy, including a new approach designed to decide whether a risk issue should be directed towards standards development as the vehicle for mitigation. This will be undertaken through the establishment of a Reliability Issues Steering Committee (RISC), which will review risks and decide on a comprehensive risk mitigation strategy – through the use of standards, guidance, training, other vehicles, or a combination of these. The Board of Trustees has endorsed this proposal, and implementation is underway in 2012 with the capability expected to be fully operational in 2013. Some of the proposed changes are expected to increase the throughput of standards; however, it is unlikely the work load in the standards function will decrease as a result. Work load will increase due to the identified need for advanced project management skills and training, more comprehensive meeting facilitation, and the applications of more specialists with technical writing skills.

**Formalize Rapid Revision Process**

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[24]

~~The SPIG has recommended that an effort to implement a cost effectiveness review of standards proposals be undertaken. Additionally, t~~The Standards Committee used the draft "Rapid Revision" process in 2011 to successfully develop a permanent modification to a standard as an alternative to processing a request for interpretation. During the first quarter of 2012, the Standards Committee identified three additional requests for interpretation as candidates for Rapid Revision. The Standard Committee expects to use these additional projects to complete "field testing" of the draft procedure and will then formalize the Rapid Revision process in the Reliability Standards development process. . This process uses the normal standard development process, but the initial formal 30-day comment period is waived because a "Rapid Revision" project is defined as a narrow revision to a standard that should not require as much industry technical vetting as more comprehensive revisions.

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**Cost Effectiveness Analysis**

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~~T~~The SPIG has also recommended that an effort to implement a cost effectiveness review of standards proposals be undertaken. The Standards Committee Process Subcommittee has formed a small team to review ~~the work~~an initiative ~~of~~by NPCC to consider cost effectiveness during the development of proposed regional standards. The small team is developing a procedure that will allow consideration of cost impacts associated with reliability standards during the standard development process.

**Realignment of Quality Review to Occur Earlier in Standards Development**

While the results of the quality review step added to the standards process have improved the overall quality of standards posted for comment, drafting teams and quality review volunteers have recommended moving the support provided by reviewers earlier in the process, before the team finalizes its initial draft of a proposed standard. The Standards Committee plans to assign additional industry personnel to newly formed drafting teams to provide legal and compliance support as the initial draft of the standard is developed. This modification ~~should~~ improve efficiency in the standards development process.

**Project Management**

A structured project management environment has been created to manage standards development. The standards staff is working with the Standards Committee to ensure that the number and complexity of standards posted for comment and ballot at the same time do~~es~~ not exceed the ability of stakeholders to provide constructive, timely comments needed to reach technical consensus.

## 2013 Goals and Deliverables

In 2013, NERC will focus standards development in two areas: (1) develop risk-based standards focused on key reliability outcomes under the prioritization process first adopted in 2011 and (2) meet~~ing~~ regulatory obligations for standards development and revisions, as specified in regulatory directives. NERC will also continue to focus on increasing the productivity and results from standards development efforts, including:

- Working with industry to implement process changes emanating from the SPIG process to improve the efficiency and timeliness of standards development such that high priority reliability risk mitigating standards may be targeted for completion. The objective of a one-year standards development cycle will be pursued.
- Implementing process changes ~~developed~~proposed by the FERC in 2012 ~~that~~to identify and slate for removal administrative requirements from existing standards where feasible and improve the throughput of the standards development process, particularly with respect to emerging reliability risks while reducing the burden on industry.
- Supporting the three-year Standards Development Plan, including development of prioritized standards and the continuing transition to results-based standards.
- Responding on an accelerated basis to (and reducing the backlog of) FERC standards related directives. Current forecasts predict 2018 for completion of the backlog, which is deemed to be too lon Current forecasts predict 2018 for completion of the backlog, which is deemed to be too long.
- Continue to improve ~~Improving~~ the quality of standards drafting, training, and communications.
- Supporting the tracking and reporting on the status of directives and filing the~~e~~ required Directives Report with the Commission.
- Tracking and reporting, on a quarterly basis, the results of the standards process.
- Providing~~e~~ technical comments in ~~along with other technical commenter's into~~ the standards development process.
- Increasing~~e~~ coordination with compliance and enforcement functions ~~particularly~~ in standards development ~~.~~ by bringing compliance considerations into the standards drafting process through simultaneous drafting of RSAWs and technical guides to aid industry application of standards.
- Structure the Standards Development portfolio into six technically distinct programs with the following project deliveries targeted based on a mid-year 2012 forecast[25]:
    - Protection Systems
        - Project 2007-06 System Protection Coordination (Q1 2013)
        - Project 2010-13.2 Phase 2 of Relay Loadability: Generation (Q4 2013)
        - Project 2010-05.2 Phase 2 of Protections Systems: SPS and RAS (2014)
    - Operations and Operations Planning
        - Project 2007-12 Frequency Response (Q2 2013)
        - Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Control: Reserves (Q3 2013)
        - Project 2008-01 Voltage and Reactive Planning and Control (2014)

[25] Note that changes in the ERO strategic direction (such as those that may be driven by the RISC effort) may require modifications to the programs and projects

- Training and Tools
  - Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities (2014)
  - Project 2010-01 Support Personnel Training (tentative)
- Modeling
  - Project 2007-09 Generator Verification (Q1 2013)
  - Project 2010-03 Modeling Data (2014)
- Practical Improvements
  - Project 2010-17 Definition of BES Phase 2 (2014)
  - Interpretations and Rapid Revisions
  - Target 4 each for completion in 2013

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## Resource Requirements

### Personnel

As part of a three-year plan, commencing in 2010, the NERC Standards Program area began to re-align its organization based on key drivers for success (improved quality and timeliness in standard development, improved accuracy and quality of web-based information, and improved stakeholder outreach); to create clear accountability for accomplishing the program mission at the strategic and tactical level; to enhance organizational efficiency in decision-making and execution; and to create a sustainable level of program activities and output.

NERC Standards Program Area management is also continually considering ways to improve the efficiency of standards development activities. In 2010, NERC gained regulatory approval of the new *Standard Processes Manual* which ~~provides~~adopted changes, consistent with ANSI requirements, for standards develop~~ers~~ment and provided the potential to shorten standards development timeframes. In 2011, NERC finished and gained approval of the initial standards development prioritization effort. Also in 2011 and continuing into 2012, NERC initiated the standards "rapid development" initiative intended to assist in the development of key standards in a shorter amount of time (targeted for a year or less). However, even with these recent process improvements, there continues to be wide spread recognition that further changes in the standards development process to improve quality and increase through put are needed.

~~-~~Additionally, management proposes to increase staff to allow an appropriate focus in the areas of project management, facilitation, and technical writing (all areas recommended by the SPIG). This will include hiring additional resources with the appropriate credentials, as well as training and/or credentialing existing personnel.

Management proposes adding three (3) additional personnel to the Standards Program area in 2013. The three additional positions ~~include~~and their functions are:

- Two standards development advisors to increase the number of concurrent standards development projects that can be processed in support of the corporate goals of developing technically sufficient results-based reliability standards, working with industry to develop options to improve the efficiency and timeliness of standards development, as well as develop technical references or application guides for reliability standards to ensure clarity and facilitate implementation.
- One standards specialist with technical writing skills to aid drafting teams in the drafting of standards and associated documents developed during the standard development process. This resource addition will facilitate improvement in the quality of the standards from the initiation of the effort (rather than relying solely on drafting teams drawn from the industry and reduce the inefficiency resulting from subsequent revisions during later stages in standards processing). The standards specialist will help drafting teams document the technical justification for proposed requirements, will help drafting teams develop effective webinar presentations, and will also provide assistance in verifying the accuracy of drafting team documents posted for public review. This

additional resource support will enable NERC to improve the quality of standards to reduce ambiguity, and improve compliance and reliability outcomes.

- The overall increase of 1.58 FTEs is the result ~~in~~of phasing of new hires during the year and the elimination of the chief reliability officer position and support staff which was partially allocated to this program area.

**Contractors and Consultants**

~~Given internal resource capabilities, the company is not projecting a need for contractors and consultants to support the standards program area in 2013. Should unforeseen needs or circumstances arise requiring additional resource support in the form of specialized or temporary contractor or consultants, these needs will be funded out of budgeted contingency reserves.~~

$150k has been included in the 2013 contractor and consulting budget to support the SPIG initiatives described above.

**Statement of Activities, Fixed Assets Expenditures and Change in Working Capital**
**2012 Budget & Projection, and 2013 Budget**
**RELIABILITY STANDARDS**

| | 2012 Budget | 2012 Projection | Variance 2012 Projection v 2012 Budget Over(Under) | 2013 Budget | Variance 2013 Budget v 2012 Budget Over(Under) | 2013 Budget Draft 1 | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|---|---|
| **Funding** | | | | | | | |
| **ERO Funding** | | | | | | | |
| NERC Assessments | $ 9,152,737 | $ 9,152,737 | $ - | $ 9,125,502 | $ (27,235) | $ 9,151,417 | $ (25,915) |
| Penalty Sanctions | - | - | | 475,325 | 475,325 | 475,325 | - |
| **Total NERC Funding** | **$ 9,152,737** | **$ 9,152,737** | **$ -** | **$ 9,600,827** | **$ 448,090** | **$ 9,626,742** | **$ (25,915)** |
| Membership Dues | - | - | - | - | - | - | - |
| Testing Fees | - | - | - | - | - | - | - |
| Services & Software | - | - | - | - | - | - | - |
| Workshops | - | 40,500 | 40,500 | 104,000 | 104,000 | - | 104,000 |
| Interest | 3,864 | 3,823 | (41) | 3,941 | 77 | 3,941 | - |
| Miscellaneous | - | - | - | - | - | - | - |
| **Total Funding (A)** | **$ 9,156,601** | **$ 9,197,060** | **$ 40,459** | **$ 9,708,768** | **$ 552,167** | **$ 9,630,683** | **$ 78,085** |
| **Expenses** | | | | | | | |
| **Personnel Expenses** | | | | | | | |
| **Salaries** | $ 3,454,036 | $ 3,068,444 | $ (385,592) | $ 3,410,423 | $ (43,613) | $ 3,456,457 | (46,034) |
| **Payroll Taxes** | 222,559 | 192,012 | (30,547) | 219,274 | (3,285) | 219,941 | (667) |
| **Benefits** | 403,907 | 277,717 | (126,190) | 361,343 | (42,564) | 361,343 | - |
| **Retirement Costs** | 489,648 | 331,452 | (158,196) | 381,381 | (108,267) | 381,381 | - |
| **Total Personnel Expenses** | **$ 4,570,150** | **$ 3,869,625** | **$ (700,525)** | **$ 4,372,421** | **$ (197,729)** | **$ 4,419,122** | **(46,701)** |
| **Meeting Expenses** | | | | | | | |
| **Meetings** | $ 107,850 | $ 148,350 | $ 40,500 | $ 164,000 | $ 56,150 | $ 107,850 | 56,150 |
| **Travel** | 447,625 | 447,625 | - | 372,500 | (75,125) | 447,625 | (75,125) |
| **Conference Calls** | 108,500 | 108,500 | - | 108,500 | - | 108,500 | - |
| **Total Meeting Expenses** | **$ 663,975** | **$ 704,475** | **$ 40,500** | **$ 645,000** | **$ (18,975)** | **$ 663,975** | **(18,975)** |
| **Operating Expenses** | | | | | | | |
| **Consultants & Contracts** | $ 15,000 | $ 12,000 | $ (3,000) | $ 150,000 | $ 135,000 | $ - | 150,000 |
| **Office Rent** | - | - | - | - | - | - | - |
| **Office Costs** | 57,818 | 96,000 | 38,182 | 77,850 | 20,032 | 57,818 | 20,032 |
| **Professional Services** | - | 684 | 684 | 700 | 700 | - | 700 |
| **Miscellaneous** | 1,000 | 1,000 | - | 1,000 | - | 1,000 | - |
| **Depreciation** | - | - | - | - | - | - | - |
| **Total Operating Expenses** | **$ 73,818** | **$ 109,684** | **$ 35,866** | **$ 229,550** | **$ 155,732** | **$ 58,818** | **$ 170,732** |
| **Total Direct Expenses** | **$ 5,307,943** | **$ 4,683,784** | **$ (624,159)** | **$ 5,246,971** | **$ (60,972)** | **$ 5,141,915** | **$ 105,056** |
| **Indirect Expenses** | **$ 4,011,842** | **$ 4,200,248** | **$ 188,406** | **$ 4,403,127** | **$ 391,285** | **$ 4,375,208** | **$ 27,919** |
| **Other Non-Operating Expenses** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |
| **Total Expenses (B)** | **$ 9,319,785** | **$ 8,884,032** | **$ (435,753)** | **$ 9,650,098** | **$ 330,313** | **$ 9,517,123** | **$ 132,975** |
| **Change in Assets** | **$ (163,184)** | **$ 313,028** | **$ 476,212** | **$ 58,669** | **$ 221,853** | **$ 113,560** | **(54,891)** |
| **Fixed Assets** | | | | | | | |
| Depreciation | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Computer & Software CapEx | - | - | - | - | - | - | - |
| Furniture & Fixtures CapEx | - | - | - | - | - | - | - |
| Equipment CapEx | - | - | - | - | - | - | - |
| Leasehold Improvements | - | - | - | - | - | - | - |
| Allocation of Fixed Assets | **$ (163,184)** | (86,774) | 76,410 | 58,669 | 221,853 | 113,560 | (54,891) |
| **Inc(Dec) in Fixed Assets ( C )** | **(163,184)** | **(86,774)** | **76,410** | **58,669** | **221,853** | **113,560** | **(54,891)** |
| **TOTAL BUDGET (=B + C)** | **$ 9,156,601** | **$ 8,797,258** | **$ (359,343)** | **$ 9,708,768** | **$ 552,167** | **$ 9,630,683** | **$ 78,085** |
| **TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)** | **$ -** | **$ 399,802** | **$ 399,802** | **$ -** | **$ (0)** | **$ -** | **$ -** |
| **FTEs** | 24.92 | 23.42 | (1.50) | 26.50 | 1.58 | 26.5 | |

## Summary of Variances by Category – 2013 Budget Compared to the 2012 Budget

- Personnel – Total Personnel Expenses are projected to decrease in 2013 due to lower average salary costs and lower benefit and retirement costs that are the result of changes to NERC's employee benefit and retirement plans.
- Meetings – Includes the cost of Workshops sponsored by the Standards Program. In 2012 and prior years, workshop expenses and the offsetting fees collected were budgeted in the

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Training Department but in 2013, workshop expenses and the offsetting fees are budgeted in the Program or Department sponsoring the event. In addition to workshops, Meeting Expenses also includes costs of the Standards Committee meetings and standards drafting team meetings.

- Consultants and Contracts – The increase is to support the SPIG initiatives as described above.

## Compliance Monitoring and Enforcement and Organization Registration and Certification

For 2011 and 2012, the Compliance Monitoring and Enforcement and Organization Registration and Certification Program was divided into three departments for operational and financial reporting purposes: (1) the Compliance Operations department; (2) the Enforcement department; and (3) Event Analysis and Investigations. Each of these departments continues to operate and ha~~ve~~s separate personnel and budgets. In 2012, NERC undertook an internal reorganization and grouped the Event Analysis department and Situation Awareness department under common leadership to better align the technical expertise within NERC to evaluate the reliability risk of events and disturbances. Financial information is being reported at the department level in order to facilitate year over year comparison.

### Compliance Operations

| Compliance Operations (in whole dollars) | 2012 Budget | 2013 Budget | Increase (Decrease) | 2013 Budget -Prior Draft | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|
| Total FTEs | 21.66 | 19.00 | (2.66) | 19.00 | - |
| Direct Expenses | $ 4,733,724 | $ 3,770,087 | $ (963,636) | $ 3,903,607 | $ (133,520) |
| Indirect Expenses | $ 3,620,723 | $ 3,156,959 | $ (463,764) | $ 3,136,942 | $ 20,017 |
| Other Non-Operating Expenses | $ - | $ - | $ - | | $ - |
| Inc(Dec) in Fixed Assets | $ (360,718) | $ (18,565) | $ 342,153 | $ (137,462) | $ 118,897 |
| Total Funding Requirement | $ 7,993,729 | $ 6,908,481 | $ (1,085,247) | $ 6,903,087 | $ 5,394 |

### Background and Scope

The Compliance Operations department is responsible for setting the strategic direction for and conducting the following activities and functions:

- Oversight of the Regional Entities' delegated compliance functions including:
  - Compliance Monitoring and Enforcement Program (CMEP) planning, implementation and reporting
  - Compliance operations, coordination and collaboration
  - Oversight of auditor training
- The Reliability Standards Audit Worksheets (RSAWs);
- The registration and certification programs, interface and outreach to the industry; and
- Support for the Operating (OC) and the Compliance and Certification Committees (CCC).

The department will continue to focus on the effectiveness of the ERO compliance monitoring activities, increasing consistency in CMEP execution through identification of inconsistencies in

compliance applications, follow up guidance to improve consistency, and by providing increased training for auditors and certification teams. NERC will also continue to participate in Regional Entity audits and certifications to support improvements in standards compliance and promote consistency throughout the industry.

### 2013 Goals and Deliverables

- Following NERC Board approval of Reliability Standards, develop a compliance trial program for those standards which allows (1) industry to mitigate compliance risk while achieving compliance with those standards and (2) the ERO to validate compliance measures and procedures. The goal is to conduct compliance trials for the three most critical of those standards approved in 2012 and 2013 that will be enforceable between 2014 and 2015; and upon completion of the compliance trial provide a report to industry of the results.

- Develop risk-based compliance monitoring approaches to maximize reliability benefits and improve efficiencies, including encouraging and recognizing the implementation of effective internal controls at registered entities. Identify and assess through pilot testing alternative risk-based approaches to monitoring compliance, including use of sampling methods. The core concept of risk-based compliance monitoring is to provide guidance to Regional Entities regarding how to appropriately scope compliance monitoring activities and methods (frequency and scope of standards to be monitored) based on each entity's potential impact to the Bulk Power System. The ERO will encourage registered entities to use the entity assessment template as a self assessment tool the year prior to an audit; and engage in discussion with the regional entity on appropriate compliance monitoring activities. The ERO will continuously assess the actively monitored list based on reliability trends, risks, and historical information and data to focus on the most critical reliability standards

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- Continue to educate the industry on effective compliance programs and reliability risk controls, including identifying and documenting case studies of entities with exemplary compliance risk and reliability risk controls. The ERO will collaborate with registered entities to develop and publish four case studies in 2013.

- 

- Develop highly qualified and trained compliance operations and auditing staffs at NERC and the Regional Entities, including (1) enhancement of qualifications in auditing, investigations, enforcement, certification evaluation and other essential compliance roles; (2) refining certification criteria for critical functions; and (3) training on auditing, investigating, root cause and human factors analysis. Conduct two ERO Compliance Enforcement Authority (CEA) auditor workshops a year; followed by a CIP specific auditor workshops. Two additional CIP auditor workshops will be conducted for a total

of four n 2013. Conduct four audit team lead courses per year and ensure all new ERO auditors complete initial integration training prior to participating in an audit.

- NERC staff will continue appropriate oversight activities of the regional entities conducting oversight of 32 regional entity audits, two per region for CIP and two per region for operations and planning standards; conducting two Key Reliability Standard Spot Checks; one for an operations and planning standard and one for a CIP standard; and conducting audit validation per the rules of procedure requirement.

- Make improvements in the consistency and transparency of compliance monitoring processes, procedures and tools, including but not limited to (1) consolidation of compliance guidance documents, (2) obtaining industry input into compliance guidance documents, and (3) working with ~~S~~standards drafting teams to facilitate compliance guidance documents during the standards development process. The ERO will update RSAWs as the primary compliance tool supporting both the audit staff and registered entities in priority based on their standing in the Actively Monitored list; revising at least 50 of the Tier one standards in 2013. Additionally for Standards under development the ERO staff will work with the standards drafting teams to produce RSAWs early in the process to facilitate an understating by both the auditors and industry prior to the effective date.

- Provide greater support to the standards development process by providing compliance and enforcement information, statistics and perspective early in the process to foster the development of standards that provide an increased reliability benefit while minimizing compliance risk uncertainties. For each Standards Authorization Request approved in 2013 provide a package of information for the standards drafting team to consider early in the process and to support concurrent development of an RSAW.

- Continue to review, update and post all of the Registration letter templates, and over 32 Certification document templates, on the NERC website.

**Regional Entity Audit Oversight**

The Compliance Operations department is charged with oversight of ~~r~~Regional ~~e~~Entity-led compliance audits (operations and planning, and Critical Infrastructure Protection (CIP)) and integrating that activity with NERC's oversight of the Regional Entities' implementation of the CMEP and other aspects of regional operations. In 2013, the department plans to oversee 24 Regional Entity-led operations and planning audits (three (3) in each region) and three (3) Regional Entity-led Spot Checks in each Region based on ~~the~~ feedback from Event Analysis. NERC's Critical Infrastructure department will support the Compliance Operations department in overseeing 21 CIP audits in 2012, a significant increase from the 14 conducted in 2011, and will further increase CIP audit oversight in 2013 with a goal of overseeing approximately 20 percent of ERO CIP Audits in 2013.

**Educating Industry**

The Compliance Operations department is also responsible for:

- facilitating the development of the registered entity assessment;
- conducting a minimum of three entity case studies;
- developing a library of examples for representative internal controls and internal compliance programs;
- consolidating compliance assessment guidance;
- transitioning RSAWs development to be concurrent for with the standards development process in order to under development to be greater better aligned with the standard drafting team's intent;
- revising current RSAWs to include greater compliance assessment information;
- continuing to develop compliance application notices to answer address consistency issues; and
- developing a communication plan for the Risk-Based Compliance Monitoring Initiative.

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**Auditor Training Activities**

NERC compliance auditor training is generally based on the United States Government Accountability Office (GAO) Generally Accepted Government Auditing Standards (GAGAS) for performance audits. In 2012, NERC teamed up with Regional Entity staff to conduct two ERO auditor workshops. The compliance auditor training material will continue to be improved based on feedback from compliance audit experiences and changes to the GAO GAGAS, the CMEP, and other NERC Rules of Procedure. Additionally, in 2012 the ERO conducted the first auditor workshops for industry representatives. In 2013, the ERO will continue to conduct two ERO auditor workshops and two industry workshops on auditor training.

**Resource Requirements**

The Compliance Operations department is not proposing to add staff positions or increase its contractor and consulting budget in 2013. The reduction in FTEs is due to the elimination of the chief reliability officer position and support staff which was partially allocated to this department in 2012 and the transfer of one position to the Information Technology Department under Administrative Services. The department's budget for contractors and consultants has been consolidated with the contractor and consulting budget for the company's NERC's risk management and internal controls.

**Statement of Activities, Fixed Assets Expenditures and Change in Working Capital**
**2012 Budget & Projection, and 2013 Budget**
**COMPLIANCE OPERATIONS and ORGANIZATION REGISTRATION and CERTIFICATION**

| | 2012 Budget | 2012 Projection | Variance 2012 Projection v 2012 Budget Over(Under) | 2013 Budget | Variance 2013 Budget v 2012 Budget Over(Under) | 2013 Budget Draft 1 | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|---|---|
| **Funding** | | | | | | | |
| **ERO Funding** | | | | | | | |
| NERC Assessments | $ 7,990,371 | $ 7,990,371 | $ - | $ 6,434,357 | $ (1,556,014) | $ 6,559,463 | $ (125,106) |
| Penalty Sanctions | - | $ - | | 340,799 | 340,799 | 340,799 | - |
| **Total NERC Funding** | **$ 7,990,371** | **$ 7,990,371** | **$ -** | **$ 6,775,156** | **$ (1,215,215)** | **$ 6,900,262** | **$ (125,106)** |
| Membership Dues | - | - | - | - | - | - | - |
| Testing Fees | - | - | - | - | - | - | - |
| Services & Software | - | - | - | - | - | - | - |
| Workshops | - | 18,025 | 18,025 | 40,000 | 40,000 | - | 40,000 |
| Interest | 3,358 | 3,058 | (300) | 2,825 | (533) | 2,825 | - |
| Miscellaneous | - | - | - | - | - | - | - |
| **Total Funding (A)** | **$ 7,993,729** | **$ 8,011,454** | **$ 17,725** | **$ 6,817,981** | **$ (1,175,748)** | **$ 6,903,087** | **$ (85,106)** |
| **Expenses** | | | | | | | |
| **Personnel Expenses** | | | | | | | |
| **Salaries** | $ 3,022,812 | $ 2,375,617 | $ (647,195) | $ 2,423,292 | $ (599,520) | $ 2,462,834 | (39,542) |
| **Payroll Taxes** | 191,988 | 151,472 | (40,516) | 156,474 | (35,514) | 157,057 | (583) |
| **Benefits** | 353,659 | 223,136 | (130,523) | 258,111 | (95,548) | 258,115 | (4) |
| **Retirement Costs** | 423,911 | 255,853 | (168,058) | 283,845 | (140,066) | 284,246 | (401) |
| **Total Personnel Expenses** | **$ 3,992,369** | **$ 3,006,078** | **$ (986,291)** | **$ 3,121,722** | **$ (870,647)** | **$ 3,162,252** | **(40,530)** |
| **Meeting Expenses** | | | | | | | |
| **Meetings** | $ 31,175 | $ 34,148 | $ 2,973 | $ 80,000 | $ 48,825 | $ 31,175 | 48,825 |
| **Travel** | 416,000 | 416,000 | - | 416,000 | - | 416,000 | - |
| **Conference Calls** | 34,235 | 34,235 | - | 34,235 | - | 34,235 | - |
| **Total Meeting Expenses** | **$ 481,410** | **$ 484,383** | **$ 2,973** | **$ 530,235** | **$ 48,825** | **$ 481,410** | **48,825** |
| **Operating Expenses** | | | | | | | |
| **Consultants & Contracts** | $ - | $ - | $ - | $ - | $ - | $ - | - |
| **Office Rent** | - | - | - | - | - | - | - |
| **Office Costs** | 39,063 | 48,000 | 8,937 | 56,000 | 16,937 | 39,063 | 16,937 |
| **Professional Services** | - | 558 | 558 | 500 | 500 | - | 500 |
| **Miscellaneous** | 2,000 | 2,000 | - | 1,000 | (1,000) | 2,000 | (1,000) |
| **Depreciation** | 218,882 | 197,203 | (21,679) | 60,630 | (158,252) | 218,882 | (158,252) |
| **Total Operating Expenses** | **$ 259,945** | **$ 247,761** | **$ (12,184)** | **$ 118,130** | **$ (141,815)** | **$ 259,945** | **$ (141,815)** |
| **Total Direct Expenses** | **$ 4,733,724** | **$ 3,738,222** | **$ (995,502)** | **$ 3,770,087** | **$ (963,637)** | **$ 3,903,607** | **$ (133,520)** |
| **Indirect Expenses** | **$ 3,620,723** | **$ 3,359,122** | **$ (261,601)** | **$ 3,156,959** | **$ (463,764)** | **$ 3,136,942** | **$ 20,017** |
| **Other Non-Operating Expenses** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **-** |
| **Total Expenses (B)** | **$ 8,354,448** | **$ 7,097,344** | **$ (1,257,103)** | **$ 6,927,047** | **$ (1,427,401)** | **$ 7,040,549** | **$ (113,502)** |
| **Change in Assets** | **$ (360,719)** | **$ 914,109** | **$ 1,274,828** | **$ (109,065)** | **$ 251,653** | **$ (137,462)** | **28,397** |
| **Fixed Assets** | | | | | | | |
| Depreciation | (218,882) | (197,203) | 21,679 | (60,630) | 158,252 | (218,882) | 158,252 |
| Computer & Software CapEx | - | - | - | - | - | - | - |
| Furniture & Fixtures CapEx | - | - | - | - | 0 | - | - |
| Equipment CapEx | - | - | - | - | 0 | - | - |
| Leasehold Improvements | - | - | - | - | 0 | - | - |
| Allocation of Fixed Assets | $ (141,836) | $ (69,397) | 72,440 | 42,065 | 183,901 | $ 81,420 | (39,355) |
| **Inc(Dec) in Fixed Assets ( C )** | **$ (360,718)** | **$ (266,600)** | **$ 94,118** | **$ (18,565)** | **$ 342,153** | **$ (137,462)** | **$ 118,897** |
| **TOTAL BUDGET (=B + C)** | **$ 7,993,729** | **$ 6,830,744** | **$ (1,162,985)** | **$ 6,908,481** | **$ (1,085,248)** | **$ 6,903,087** | **$ 5,394** |
| **TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)** | **$ (0)** | **$ 1,180,709** | **$ 1,180,710** | **$ (90,500)** | **$ (90,500)** | **$ -** | **$ (90,500)** |
| **FTEs** | **21.66** | **18.73** | **(2.93)** | **19.00** | **(2.66)** | **19.00** | **-** |

## Summary of Variances by Category – 2013 Budget Compared to the 2012 Budget

- Personnel Expenses – The decrease in Personnel Expenses is related to a reduction of 2.66 FTEs in the department who transferred to other departments in 2012 and related to changes in NERC's employee benefit and retirement plans as previously described.

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- Meetings expense includes the cost of the Compliance Auditor workshops and meetings of the Compliance and Certification Committee. $40k in projected Workshop Fees offset the $48.8k increase in Meetings Expense.

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## Compliance Enforcement

| Compliance Enforcement (in whole dollars) | 2012 Budget | 2013 Budget | Increase (Decrease) | 2013 Budget -Prior Draft | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|
| Total FTEs | 21.00 | 21.00 | - | 21.00 | - |
| Direct Expenses | $ 3,284,789 | $ 3,160,329 | $ (124,459) | $ 3,180,787 | $ (20,458) |
| Indirect Expenses | $ 3,298,184 | $ 3,489,271 | $ 191,087 | $ 3,467,146 | $ 22,125 |
| Other Non-Operating Expenses | $ - | $ - | $ - | | $ - |
| Inc(Dec) in Fixed Assets | $ (137,515) | $ 46,493 | $ 184,007 | $ 89,991 | $ (43,498) |
| Total Funding Requirement | $ 6,445,458 | $ 6,696,092 | $ 250,635 | $ 6,737,924 | $ (41,832) |

### Background and Scope

NERC's Compliance Enforcement department conducts all of NERC's enforcement activities, including:

- Docketing of all possible violations coming into the NERC enforcement program;
- Processing of compliance violation matters arising out of NERC-led investigations and audits;
- Review of all mitigation plans accepted and dismissals approved by Regional Entities;
- Processing of all compliance violations arising out of Regional Entity compliance, enforcement and monitoring activities; and
- Analysis of compliance statistics.

A priority for this department is to achieve greater efficiencies in enforcement processing by ensuring Possible Violations are mitigated and, at the same time, focusing both NERC and Regional Entity compliance enforcement resources on the cases that have the greatest impact on the reliability of the bulk power system.

A summary of NERC and the Regional Entity caseload showing all current outstanding violations, summarized by state and region as of April 2, 2012, is set forth below[26].

[26] State 1:Assessment and Validation
State 2:Confirmation
State 3:Regulatory Filings

| | State 1<br>Assessment and Validation | State 2<br>Confirmation | Settlement | State 3<br>Regulatory Filings | State 4<br>Filed/Awaiting Closing Actions | State 5<br>Completed and Closed | |
|---|---|---|---|---|---|---|---|
| FRCC | 89 | 0 | 6 | 0 | 65 | 250 | 410 |
| MRO | 135 | 0 | 6 | 2 | 33 | 168 | 344 |
| NCEA[27] | 27 | 0 | 0 | 0 | 9 | 37 | 73 |
| NPCC | 84 | 13 | 12 | 7 | 19 | 193 | 328 |
| RFC | 450 | 4 | 4 | 42 | 184 | 454 | 1138 |
| SERC | 437 | 2 | 142 | 5 | 22 | 336 | 944 |
| SPP | 279 | 0 | 41 | 0 | 102 | 239 | 661 |
| TRE | 219 | 11 | 59 | 9 | 66 | 120 | 484 |
| WECC | 295 | 168 | 286 | 130 | 262 | 1209 | 2350 |
| TOTAL | 2015 | 198 | 556 | 195 | 762 | 3006 | 6732 |
| Percentage of Total | 29.93% | 2.94% | 8.26% | 2.90% | 11.32% | 44.65% | |

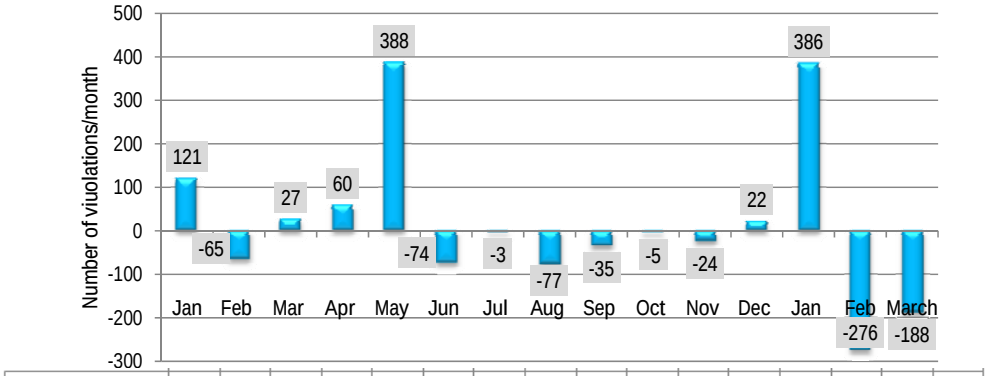
## 2013 Goals and Deliverables

### Increased Processing Efficiencies

Throughout 2013, NERC Compliance Enforcement will seek to develop further mechanisms to enhance processing efficiency. NERC has introduced two new concepts in enforcement processing through its Compliance Enforcement Initiative (CEI): the Spreadsheet NOP (SNOP), and Find, Fix, Track, and Report (FFT). These new approaches are designed to expedite and streamline violation processing, which allows focus to be re-directed to those risks that have the greatest impact on the reliability of the bulk power system. Implementation of these initiatives has reduced the overall ERO enforcement caseload and should allow NERC to close out cases more expeditiously to provide timely lessons learned to the industry. In recent months, due to the new CEI processes, the monthly processing rate (which includes both filed and dismissed violations) has resulted in more violations being processed than submitted in eight of the last 10 months, as shown on Figure 1.

State 4:Filed / Awaiting Closing Actions
State 5:Completed and Closed

[27] NCEA means NERC Compliance Enforcement Authority




| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| New | 218 | 212 | 190 | 219 | 581 | 223 | 211 | 166 | 262 | 247 | 212 | 203 | 545 | 131 | 171 | 3791 |
| Dismissed and Filed | 97 | 277 | 163 | 159 | 193 | 297 | 214 | 243 | 297 | 252 | 236 | 181 | 159 | 407 | 359 | 3534 |

**Figure 1: Violation Processing in 2011 and 2012**

**Sustain and Expand CEI Processes**

Throughout the remainder of 2012 and into 2013, NERC Compliance Enforcement will be focusing efforts on ensuring the sustainability and expandability of the FFT process. Sustainability requires that there be consistency in application. NERC intends to promote consistency through a series of training and outreach sessions for Regional Entity enforcement and compliance staff on the identification and disposition of possible violations as FFTs. Expandability not only applies to who may identify FFTs but also an expansion of the effectiveness of the program. Beginning in 2013, NERC will be expanding FFT identification to CEA compliance staff. NERC anticipates that expanding FFT identification will broaden the range of issues that will be afforded FFT treatment much earlier in the compliance monitoring and enforcement process. This earlier application will likely improve mitigation results as there will be an increased incentive to mitigate minimal risk issues earlier on to qualify for FFT treatment. Faster identification and application of mitigation activities will result in improved reliability.

**Reduction of ~~Prior~~Outstanding Caseload**

Another aspect of caseload management is the timely processing of all violations, particularly those that pose greater risk to the bulk power system, and to provide lessons learned to the industry. Early dissemination of violation information to registered entities will enable them to learn from prior events and violations so they may take action to eliminate similar risks that may occur elsewhere on the bulk power system. There are approximately 967 possible violations spanning 2007 through 2010 (including those on hold due to related jurisdictional issues) of CIP and non-CIP ~~active violations~~ standards that have not been filed with FERC. NERC Compliance Enforcement has initiated an effort ~~not only~~ to identify these aging possible violations ~~but also~~and to identify the reason for their processing delay and identify which

possible violations pose the greatest risk to reliability. Compliance Enforcement plans to work with the Regional Entities to significantly reduce this prior caseload by bringing the possible violations to closure and ~~get~~thereby obtain information on prior violations to registered entities throughout the remainder of 2012 and in 2013.

**Violation Trend Analysis**

In 2013, Compliance Enforcement also plans to identify the causes and trends of violations in enforcement cases. Over the past five years, NERC has been collecting violations processing information in its Compliance Reporting and Tracking System (CRATS) database. This database now contains a significant amount of information pertaining to the facts and circumstances, risk evaluation and mitigation activities of prior violations. Review and evaluation of this information can yield insight into the effectiveness of NERC and the Regional Entities' training programs, registered entities application of past lessons learned and the NERC Reliability Standards in ensuring reliability. Analysis of the information contained in NERC's CRATS database should enable NERC Compliance Enforcement to provide guidance on where additional training may be needed or where revisions to the standards could promote greater clarity.

## Resource Requirements

**Personnel**

Departmental and Regional Entity resource enforcement capabilities have increased through the addition of staff over the past several years. Beginning in September 2011, NERC also introduced several new concepts in enforcement processing through its Compliance Enforcement Initiative. These new approaches are designed to expedite and streamline violation processing for minimal risk violations, which allow focus to be re-directed to those areas that have the greatest impact on the reliability of the BPS. It is still too early in the implementation of these approaches to determine the degree of overall efficiencies that will be gained. However, it is anticipated that the result will be a downward pressure on future enforcement staffing requirements in the 2014-2015 timeframe. As this timeframe is approached, enforcement objectives and the commensurate resource requirements. No further enforcement resource additions are being proposed by NERC in 2013.

**Contractor Expenses**

No contractor or consulting resources are proposed within the group for 2013. Resource requirements associated with improvements to the applications supporting the department's compliance reporting, analysis and tracking needs have are budgeted under the IT department.

**Statement of Activities, Fixed Assets Expenditures and Change in Working Capital**
**2012 Budget & Projection, and 2013 Budget**
**COMPLIANCE ENFORCEMENT**

| | 2012 Budget | 2012 Projection | Variance 2012 Projection v 2012 Budget Over(Under) | 2013 Budget | Variance 2013 Budget v 2012 Budget Over(Under) | 2013 Budget Draft 1 | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|---|---|
| **Funding** | | | | | | | |
| **ERO Funding** | | | | | | | |
| NERC Assessments | $ 6,442,202 | $ 6,442,202 | $ 0 | $ 6,316,297 | $ (125,905) | $ 6,358,129 | $ (41,832) |
| Penalty Sanctions | - | $ - | | 376,673 | 376,673 | 376,673 | - |
| **Total NERC Funding** | **$ 6,442,202** | **$ 6,442,202** | **$ 0** | **$ 6,692,970** | **$ 250,768** | **$ 6,734,801** | **$ (41,832)** |
| Membership Dues | - | - | - | - | - | - | - |
| Testing Fees | - | - | - | - | - | - | - |
| Services & Software | - | - | - | - | - | - | - |
| Workshops | - | - | - | - | - | - | - |
| Interest | 3,256 | 3,190 | (66) | 3,123 | (133) | 3,123 | - |
| Miscellaneous | - | - | - | - | - | - | - |
| **Total Funding (A)** | **$ 6,445,458** | **$ 6,445,392** | **$ (66)** | **$ 6,696,092** | **$ 250,634** | **$ 6,737,924** | **$ (41,832)** |
| **Expenses** | | | | | | | |
| **Personnel Expenses** | | | | | | | |
| **Salaries** | $ 2,310,485 | $ 2,106,698 | $ (203,787) | $ 2,244,609 | $ (65,876) | $ 2,335,812 | (91,203) |
| **Payroll Taxes** | 158,938 | 136,951 | (21,987) | 149,247 | (9,691) | 153,882 | (4,635) |
| **Benefits** | 334,684 | 233,155 | (101,529) | 270,680 | (64,004) | 270,743 | (63) |
| **Retirement Costs** | 329,353 | 213,289 | (116,064) | 262,293 | (67,060) | 269,021 | (6,728) |
| **Total Personnel Expenses** | **$ 3,133,460** | **$ 2,690,093** | **$ (443,367)** | **$ 2,926,829** | **$ (206,631)** | **$ 3,029,458** | **(102,629)** |
| **Meeting Expenses** | | | | | | | |
| **Meetings** | $ - | $ 100 | $ 100 | $ 5,000 | $ 5,000 | $ - | 5,000 |
| **Travel** | 128,000 | 128,000 | - | 186,000 | 58,000 | 128,000 | 58,000 |
| **Conference Calls** | - | 3,000 | 3,000 | - | - | - | - |
| **Total Meeting Expenses** | **$ 128,000** | **$ 131,100** | **$ 3,100** | **$ 191,000** | **$ 63,000** | **$ 128,000** | **63,000** |
| **Operating Expenses** | | | | | | | |
| **Consultants & Contracts** | $ - | $ - | $ - | $ - | $ - | $ - | - |
| **Office Rent** | - | - | - | - | - | - | - |
| **Office Costs** | 23,329 | 36,000 | 12,671 | 41,000 | 17,671 | 23,329 | 17,671 |
| **Professional Services** | - | 480 | 480 | 500 | 500 | - | 500 |
| **Miscellaneous** | - | 1,000 | 1,000 | 1,000 | 1,000 | - | 1,000 |
| **Depreciation** | - | - | - | - | - | - | - |
| **Total Operating Expenses** | **$ 23,329** | **$ 37,480** | **$ 14,151** | **$ 42,500** | **$ 19,171** | **$ 23,329** | **$ 19,171** |
| **Total Direct Expenses** | **$ 3,284,789** | **$ 2,858,673** | **$ (426,116)** | **$ 3,160,329** | **$ (124,460)** | **$ 3,180,787** | **$ (20,458)** |
| **Indirect Expenses** | **$ 3,298,184** | **$ 3,504,391** | **$ 206,208** | **$ 3,489,271** | **$ 191,087** | **$ 3,467,146** | **$ 22,125** |
| **Other Non-Operating Expenses** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **-** |
| **Total Expenses (B)** | **$ 6,582,973** | **$ 6,363,064** | **$ (219,908)** | **$ 6,649,600** | **$ 66,627** | **$ 6,647,933** | **$ 1,666** |
| **Change in Assets** | **$ (137,515)** | **$ 82,328** | **$ 219,842** | **$ 46,493** | **$ 184,007** | **$ 89,991** | **(43,498)** |
| **Fixed Assets** | | | | | | | |
| Depreciation | - | - | - | - | - | - | - |
| Computer & Software CapEx | - | - | - | - | - | - | - |
| Furniture & Fixtures CapEx | - | - | - | - | 0 | - | - |
| Equipment CapEx | - | - | - | - | 0 | - | - |
| Leasehold Improvements | - | - | - | - | 0 | - | - |
| Allocation of Fixed Assets | $ (137,515) | $ (72,398) | 65,117 | 46,493 | 184,007 | $ 89,991 | (43,498) |
| **Inc(Dec) in Fixed Assets ( C )** | **$ (137,515)** | **$ (72,398)** | **$ 65,117** | **$ 46,493** | **$ 184,007** | **$ 89,991** | **$ (43,498)** |
| **TOTAL BUDGET (=B + C)** | **$ 6,445,458** | **$ 6,290,666** | **$ (154,792)** | **$ 6,696,092** | **$ 250,634** | **$ 6,737,924** | **$ (41,832)** |
| **TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)** | **$ (0)** | **$ 154,725** | **$ 154,726** | **$ -** | **$ 0** | **$ -** | **$ -** |
| **FTEs** | **21.00** | **19.54** | **(1.46)** | **21.00** | **-** | **21.00** | **-** |

## Summary of Variances by Category – 2013 Budget Compared to the 2012 Budget

- Personnel Expenses – Related to lower average salary expense per FTE and due to changes to NERC's employee benefit and retirement plans as previously described.

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## Reliability Assessment and Performance Analysis

| Reliability Assessments and Performance Analysis (in whole dollars) | 2012 Budget | 2013 Budget | Increase (Decrease) | 2013 Budget -Prior Draft | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|
| Total FTEs | 16.50 | 18.75 | 2.25 | 18.75 | - |
| Direct Expenses | $ 4,437,752 | $ 4,594,564 | $ 156,812 | $ 4,496,839 | $ 97,725 |
| Indirect Expenses | $ 2,656,316 | $ 3,115,420 | $ 459,104 | $ 3,095,666 | $ 19,754 |
| Other Non-Operating Expenses | $ - | $ - | $ - | | $ - |
| Inc(Dec) in Fixed Assets | $ (125,208) | $ 4,061 | $ 129,269 | $ 63,187 | $ (59,126) |
| Total Funding Requirement | $ 6,968,860 | $ 7,714,046 | $ 745,185 | $ 7,655,693 | $ 58,353 |

### Background and Scope

NERC's Reliability Assessments and Performance Analysis (RAPA) program conducts annual seasonal and long-term reliability assessments, designed to assess existing and planned short and long-term resource adequacy and operating reliability. Further, the program identifies and assesses probability and severity of risks to of reliability performance, measures progress in improving current reliability, tracks leading indicators of future reliability, develops risk control solutions, measures success of theseis solutions and provides risk-informed information into NERC's standards and compliance processes. Finally, RAPA provides engineering expertise focused on protection and control along with system analysis and modeling to study system disturbances, develop reliability guidelines, and support NERC Reliability Standards development. To support these activities, RAPA maintains detailed databases measuring the planned and ongoing reliability performance of generation, transmission and demand response resources.

RAPA also identifies and analyzes key emerging issues that may affect reliability, such as market practices, legislation, regulation, technology developments, high-impact, low-frequency (HILF) events, industry trends, interconnection-wide modeling improvement, and proposed public policy measures, and documents these in special reliability assessments.

RAPA's resource needs are driven and supported by NERC's strategic plan, FERC directives, the Board of Trustees, the Member Representatives Committee, and the Electricity Sub-sector Coordinating Council, along withand the Planning, Operating, Critical Infrastructure Protection, Standards, and Compliance and Certification Committees' strategic work plans, along withas well as their subcommittees, working groups, and task forces.

## 2013 Goals and Deliverables

- ~~Complete development of and obtain Board approval of a revised definition of adequate level of reliability of the bulk electric system, through collaboration with industry stakeholders and standing committees.~~
- Issue reliability assessment reports, guidelines, recommendations and alerts as needed.
  - One 10-year Long-Term Reliability Assessment
  - Two seasonal assessments: Summer and Winter
  - Two equipment reliability reports: Transmission (TADS) and Generating (GADS)
  - Report on geomagnetic disturbance (GMD) bulk electric system effects and vulnerability assessment
  - Up to two additional special assessments addressing key reliability issues, such as:
    - Environmental regulations
    - Gas and electric interdependency and coordination
    - Changing resource mix
  - One Annual State of Reliability Report
  - Oversight of Generating, Transmission and Demand Response Availability Data Systems (GADS, TADS, and DADS)
  - Strengthen data collection and validation processes by designing, creating, testing, and implementing data checking systems for reliability assessment and risk analysis
  - Provide quarterly updates on trends and measures of bulk electric system reliability
- Development of risk control strategies and plans to address existing or emerging risks to bulk electric system reliability, as well as initiate cross functional risk control project teams to develop and implement risk management strategies for the highest priority risk clusters.
- Support NERC Reliability Standard development and response to FERC Directives by providing technical and system analysis expertise.
- Support development of reliability standards to address deficiencies or needs revealed by reliability assessments and performance analysis.
- Provide support and leadership to the Planning Committee, and Standing Committees' subcommittees, working groups, and task forces serving the Standing Committees.
- Build and sustain an enterprise reliability assessment and performance analysis team.
- Depending on~~f~~ regulatory action, finalize Bulk Electric System and consequential load loss exception processes.

**Resource Requirements**

**The company has not proposed incremental personnel or new contractor and consulting resources associated with BES implementation due to the uncertainty of the timing and impact on NERC's resources requirements. However, the company has identified BES as a contingency for which operating reserves might be used to hire additional expert consultants to assist in the BES implementation process should it be necessary. For further information regarding the Company's proposed Working Capital and Operating Reserve Policy and the amounts included for contingencies like BES please refer to Exhibit C.**

**Personnel**

During 2012 the department added a manager of engineering to support the reliability and system analysis and one engineer to spearhead NERC's bulk electric system risk identification and control strategy. In 2013, to further strengthen NERC's bulk electric system risk control processes, the department is proposing to add a risk control coordination specialist. This position will support NERC's initiatives to identify, evaluate and prioritize bulk power system risks as well as supporting NERC's special risk control project teams by providing project management and high-level risk measurement. The chart above reflects 2.25 FTE additions due to the full year effect of the timing of personnel additions in 2012.

**Contractor Expenses**

The total projected contractor and consultant expenses for the department are projected at $685~~743~~k, which is below 2012 budgeted levels. The type of consultant and contractor resources required are generally consistent with historic needs and include support for the following:

- *Geomagnetic Disturbance (GMD) Vulnerability Assessment*
  GMD is a concern to the North American bulk electric system due to increasing awareness, grid complexity, and societal dependence on reliable electricity supply. GMD has the potential to cause system disturbances and equipment damage. In an extreme case, GMD may have the potential to cause wide spread electric disruption and damage long-lead time equipment, such as transformers. Though severe events are rare, the impacts can be unacceptable and therefore industry action is needed. Industry needs a clear understanding of the probable storm activity and system impact based on fact-based analysis to develop appropriate mitigation solutions. Additionally, the industry needs a better understanding of available technologies and approaches to limit the extent and duration of GMD events. This project's 2013 objectives are:
  - Determine the likely impact of an extreme event, as defined above, on the North American bulk power system based on present system configuration, protection capability, and practices.
  - Identify technologies available today (especially in operations), or in the near term, to mitigate equipment damage, reduce the extent of the interruption, and speed recovery. Identify technologies that can be developed to reduce the impact of the storm as well as lower the cost of protection.
- *Scenario Consultant – Addressing Standing and Emerging Issues*

Scenario assessments provide detailed quantitative and qualitative analyses which "stress" the reference planning case of the North American bulk power system. The data which supports the reference planning case is data that NERC collects and aggregates for the development of each year's Long-Term Reliability Assessment (LTRA) report. Scenario analysis can indicate the relative sensitivity of the *Reference Case* to changes in pre-specified conditions and may provide some insight into risks to Regional reliability. Based on feedback from FERC and industry, a deeper understanding is desired regarding the potential reliability implications of a focused spectrum of *Reference Case* sensitivities. Development of a set of scenarios for comparison to the *Reference Case* is an extremely valuable way to better understand the robustness of the *Reference Case* and to study potential impacts of scenarios on reliability.

NERC will continue to develop ad-hoc Special and/or Scenario Assessments which are developed through the Emerging Issues process currently established in the LTRA.[28] Scenarios for Special Assessments are unknown at this time, but may focus on key reliability issues, such as:

- Environmental regulations;
- Gas and electric interdependency and coordination; and
- Changing resource mix.

- *Benchmarking and Generator Controls Modeling*
  Interconnection modeling and system protection and control improvement activities will continue into 2013. Work in 2013 will require engaging subject matter expert contractors in generation protection and control.
- *Databases and Availability Systems*
  - RADS Assessment Database – Continued Development

    FERC has directed NERC to consider establishing permanent databases that could be automatically populated with: (i) new transmission projects data from the RE's, (ii) generation interconnection queue data, and (iii) other data relevant for reliability assessment. The goal of the NERC Reliability Assessment Data System (RADS) is meet these requirements. RADS will facilitate the collection of Regional generation and transmission data to quantify and analyze the reliability of the bulk power system in a standard, uniform method. Reliability planners use generation and transmission data to ensure existing and future resource adequacy in accordance with NERC reliability requirements. The technical side of the RADS project, including database design, contractor selection, and acceptance testing will be managed

[28] **Special Assessments** are ad-hoc assessments focused on specific industry issues (emerging or standing). For these assessments, detailed quantitative and qualitative analysis, beyond what is included in the annual long-term and seasonal reliability assessments, is examined. These reports are generally published separately from the annual long-term and seasonal reliability assessments.

**Scenario Assessments** are ad-hoc assessments focused on specific, hypothetical industry conditions. For these assessments, detailed quantitative and qualitative analysis is performed which "stress" the Reference Case. Scenario assessments will be included as part of the annual long-term and seasonal reliability assessments to provide a sensitivity of potential outcomes.

cooperatively between NERC and its Regional Entities through the NERC Project Management Office (PMO). Specifications of what data will be collected in this system will be developed by the Reliability Assessment Data Working Group (RADWG). The RADS project was initiated and funded in NERC's FERC approved 2012 budget. These incremental funds will lead to its completion in 2013.

- Metrics and Benchmarking Database – Enhancements and Maintenance

  Collects, records, and retrieves reliability metric information that quantifies characteristics of adequate level of reliability. The metric trends and performance analysis serve as technical input to Reliability Standards and project prioritization, compliance process improvement, event analysis, reliability assessment, and critical infrastructure protection.

- Spare Equipment Database(SED) – Enhancements and Maintenance

  ~~Spare Equipment Database (SED) –~~ Collects and tracks spare long-lead time transformer information to strengthen the resiliency of the bulk electric system after a significant event that damages large amounts of equipment. The database provides industry a vital tool of communication and coordination for tracking spare equipment. This will be extremely helpful in the aftermath of a HILF event, such as coordinated attack or extreme weather.

- Generation Availability Data System (GADS) – Enhancements and Maintenance

  Collects, records, and retrieves operating information on power plant availability, including event, performance, and design data. The information is used to support equipment reliability and availability analyses and risk-informed decision making. It also offers industry a unique service for locating peer units of similar design and operating characteristics that establishes performance benchmarks for improving individual unit reliability and availability. The 2013 budget reflects a reduction of $250k in revenue from licensing the GADS software to third parties, which NERC no longer plans to actively pursue. In the event that NERC does receive revenue from third parties for licensing of GADS these revenues will be captured as part of working capital.

- Transmission Availability Data System (TADS) – Enhancements and Maintenance

  Provides a uniform approach to reporting and measuring transmission availability and performance. The data reporting tool collects information about the transmission lines and transformers operating above 200kV, including outage details and cause codes.

- Demand Response Availability Data System (DADS) – Enhancements and Maintenance

  Collects demand response enrollment and event information to measure its actual performance including its contribution to improved reliability. The availability analysis can provide industry with a consistent basis for projecting contributions of

dispatchable and non-dispatchable demand response supporting forecast adequacy and operational reliability.

Exhibit B includes additional information regarding the amount of proposed contractor and consulting funding to support each of the above areas, together with a comparison to 2012 budgeted amounts.

**Statement of Activities, Fixed Assets Expenditures and Change in Working Capital**
**2012 Budget & Projection, and 2013 Budget**
**RELIABILITY ASSESSMENTS and PERFORMANCE ANALYSIS**

| | 2012 Budget | 2012 Projection | Variance 2012 Projection v 2012 Budget Over(Under) | 2013 Budget | Variance 2013 Budget v 2012 Budget Over(Under) | 2013 Budget Draft 1 | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|---|---|
| **Funding** | | | | | | | |
| **ERO Funding** | | | | | | | |
| NERC Assessments | $ 6,716,302 | $ 6,716,302 | $ - | $ 7,334,943 | $ 618,641 | $ 7,316,590 | $ 18,353 |
| Penalty Sanctions | - | - | | 336,315 | 336,315 | 336,315 | - |
| **Total NERC Funding** | **$ 6,716,302** | **$ 6,716,302** | **$ -** | **$ 7,671,258** | **$ 954,956** | **$ 7,652,905** | **$ 18,353** |
| Membership Dues | - | - | - | - | - | - | - |
| Testing Fees | - | - | - | - | - | - | - |
| Services & Software | 250,000 | 125,000 | (125,000) | - | (250,000) | - | - |
| Workshops | - | - | - | 40,000 | 40,000 | - | 40,000 |
| Interest | 2,558 | 2,761 | 203 | 2,788 | 230 | 2,788 | - |
| Miscellaneous | - | - | - | - | - | - | - |
| **Total Funding (A)** | **$ 6,968,860** | **$ 6,844,063** | **$ (124,797)** | **$ 7,714,046** | **$ 745,186** | **$ 7,655,693** | **$ 58,353** |
| **Expenses** | | | | | | | |
| **Personnel Expenses** | | | | | | | |
| **Salaries** | $ 2,189,610 | $ 2,287,607 | $ 97,998 | $ 2,505,205 | $ 315,596 | $ 2,540,569 | (35,364) |
| **Payroll Taxes** | 141,720 | 142,207 | 488 | 154,907 | 13,188 | 155,419 | (512) |
| **Benefits** | 266,523 | 203,282 | (63,241) | 245,403 | (21,120) | 245,403 | - |
| **Retirement Costs** | 313,238 | 253,980 | (59,258) | 283,758 | (29,480) | 283,786 | (28) |
| **Total Personnel Expenses** | **$ 2,911,090** | **$ 2,887,076** | **$ (24,014)** | **$ 3,189,273** | **$ 278,183** | **$ 3,225,177** | **(35,904)** |
| **Meeting Expenses** | | | | | | | |
| **Meetings** | $ 12,500 | $ 47,500 | $ 35,000 | $ 78,000 | $ 65,500 | $ 12,500 | 65,500 |
| **Travel** | 369,375 | 369,375 | - | 410,000 | 40,625 | 369,375 | 40,625 |
| **Conference Calls** | 31,950 | 31,950 | - | 31,950 | - | 31,950 | - |
| **Total Meeting Expenses** | **$ 413,825** | **$ 448,825** | **$ 35,000** | **$ 519,950** | **$ 106,125** | **$ 413,825** | **106,125** |
| **Operating Expenses** | | | | | | | |
| **Consultants & Contracts** | $ 998,000 | $ 957,000 | $ (41,000) | $ 685,000 | $ (313,000) | $ 743,000 | (58,000) |
| **Office Rent** | - | - | - | - | - | - | - |
| **Office Costs** | 93,676 | 130,957 | 37,281 | 161,416 | 67,740 | 93,676 | 67,740 |
| **Professional Services** | - | 498 | 498 | 475 | 475 | - | 475 |
| **Miscellaneous** | 4,000 | 447 | (3,554) | 1,000 | (3,000) | 4,000 | (3,000) |
| **Depreciation** | 17,161 | 44,713 | 27,552 | 37,450 | 20,289 | 17,161 | 20,289 |
| **Total Operating Expenses** | **$ 1,112,837** | **$ 1,133,615** | **$ 20,778** | **$ 885,341** | **$ (227,496)** | **$ 857,837** | **$ 27,504** |
| **Total Direct Expenses** | **$ 4,437,752** | **$ 4,469,516** | **$ 31,764** | **$ 4,594,564** | **$ 156,812** | **$ 4,496,839** | **$ 97,725** |
| **Indirect Expenses** | **$ 2,656,316** | **$ 3,032,715** | **$ 376,399** | **$ 3,115,420** | **$ 459,104** | **$ 3,095,666** | **$ 19,754** |
| **Other Non-Operating Expenses** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **-** |
| **Total Expenses (B)** | **$ 7,094,068** | **$ 7,502,231** | **$ 408,163** | **$ 7,709,985** | **$ 615,917** | **$ 7,592,506** | **$ 117,479** |
| **Change in Assets** | **$ (125,208)** | **$ (658,169)** | **$ (532,961)** | **$ 4,061** | **$ 129,269** | **$ 63,187** | **(59,126)** |
| **Fixed Assets** | | | | | | | |
| Depreciation | (17,161) | (44,713) | (27,552) | (37,450) | (20,289) | (17,161) | (20,289) |
| Computer & Software CapEx | - | 15,726 | 15,726 | - | - | - | - |
| Furniture & Fixtures CapEx | - | - | - | - | - | - | - |
| Equipment CapEx | - | - | - | - | - | - | - |
| Leasehold Improvements | - | - | - | - | - | - | - |
| Allocation of Fixed Assets | $ (108,047) | $ (62,653) | $ 45,394 | 41,511 | $ 149,558 | $ 80,349 | (38,838) |
| **Inc(Dec) in Fixed Assets ( C )** | **$ (125,208)** | **$ (91,641)** | **$ 33,567** | **$ 4,061** | **$ 129,269** | **$ 63,187** | **$ 20,289** |
| **TOTAL BUDGET (=B + C)** | **$ 6,968,860** | **$ 7,410,591** | **$ 441,731** | **$ 7,714,046** | **$ 745,186** | **$ 7,655,693** | |
| **TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)** | **$ -** | **$ (566,528)** | **$ (566,528)** | **$ -** | **$ -** | **$ -** | **$ -** |
| **FTEs** | **16.50** | **16.91** | **0.41** | **18.75** | **2.25** | **18.75** | **-** |

Summary of Variances by Category – 2013 Budget Compared to the 2012 Budget

- Personnel Expenses – Salaries and Payroll Taxes will increase in 2013 due to having 2.25 more FTEs on staff than 2012, while Benefits and Retirement Costs

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are projected to be lower due to changes to NERC's emeployee benefit and retirement plans.

- Meeting, Travel and Conferencing Expenses – Meetings expense includes costs related to workshops sponsored by the RAPA Program that were previously recorded in the Training Program. The increase in Meetings expense is substantially offset by $40k in projected Workshop Fees. The increase in Travel expense is related to the additional FTEs budgeted in 2013.
- The decrease in Consultants and Contracts expense was described above.

## Reliability Risk Management

NERC's Reliability Risk Management group includes three primary functions and two departments. The three primary functions include: (1) bulk power system awareness; (2) event analysis and investigations; and (3) assessment of human performance challenges affecting bulk power system reliability and identification of improvement opportunities. The two departments include the Situation Awareness Department[29] and the Event Analysis and Investigations Department[30]. In the 2012 budget the Situation Awareness department was consolidated under the Situation Awareness and Critical Infrastructure Security Program Area and the budget for the Event Analysis and Investigations department was consolidated under the Compliance Enforcement and Organizational Registration Program Area.

The Reliability Risk Management group actively engages with and seeks comments and input from the North American Transmission Forum regarding operational alerts, best practices and technical input for lessons learned. This group has also been engaged in an ongoing dialogue with the Generator Forum regarding winter preparation for generators, including recommendations from the cold snap report.

### Situation Awareness Department

| Situation Awareness (in whole dollars) | 2012 Budget | 2013 Budget | Increase (Decrease) | 2013 Budget - Prior Draft | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|
| Total FTEs | 8.17 | 6.50 | (1.67) | 6.50 | - |
| Direct Expenses | $ 5,320,471 | $ 3,953,379 | $ (1,367,092) | $ 3,956,743 | $ (3,364) |
| Indirect Expenses | $ 1,777,691 | $ 1,080,012 | $ (697,678) | $ 1,073,164 | $ 6,848 |
| Other Non-Operating Expenses | $ - | $ - | $ - | | $ - |
| Inc(Dec) in Fixed Assets | (120,163) | 6,996 | 127,159 | (19,999) | 26,995 |
| Total Funding Requirement | $ 6,977,998 | $ 5,040,387 | $ (1,937,611) | $ 5,009,908 | $ 30,479 |

### Background and Scope

NERC Situation Awareness personnel work closely with Regional Entities and governmental ~~authorities~~authorities' situation awareness personnel, including FERC, to share information regarding system events and risks to the reliability of the bulk power system.

In 2009, NERC engaged Industry in the development of the original SAFNR V1 project, working with the Regional Entities, FERC staff and industry representatives to identify an initial set of data to accommodate and acceptable level of situation awareness. After approximately a year of experience with the SAFNR V1 system, a SAFNR V2 project team was formed consisting again

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[29] This department is now called Bulk Power System Awareness. Situation awareness is a function within this group.
[30] Since there is only one person presently dedicated to the human performance function, personnel and other costs associated with this function are consolidated with Events Analysis department costs in order to protect the confidentiality of compensation information.

of industry representatives[31], the Regional Entities, NERC and FERC staff to further refine data requirements, enhance data displays, and address other identified needs. Reliability Coordinators were included in shared documentation and decisions made throughout the development of Version 2.

In 2011, NERC executed a contract for the design, installation and maintenance of the SAFNR V2a ~~known as SAFNR V2~~ platform for the collection and display of key system information from Reliability Coordinators. This platform permits NERC, the Regional Entities, and governmental authorities to collect and display key information with common forms and formats. The single approach supports industry by establishing a single data sharing process and protocol as opposed to multiple processes and protocols for NERC, Regions, and governmental authorities thereby eliminating duplication of efforts. During 2012 SAFNR V2 became operational displaying bulk power system data from the 12 Reliability Coordinators from across the three United States interconnections. SAFNR will enable the ERO to increase its awareness and understanding of HILF events. This platform has not been designed nor is it intended to be used to direct registered entity ~~operations.~~

operations. FERC staff also monitors the situational awareness of the bulk power system and will have the capability to use the enhanced features of SAFNR V2 in the coming months. As future refinements and enhancements are needed to the SAFNR V2 system, NERC will again reach out to the Regional Entities, Reliability Coordinators, and FERC staff to develop and implement those enhancements. Industry has been a key participant in the development and implementation of SAFNR, The process for any future enhancement will continue to occur in a organized and logistical manner with notice to and ongoing opportunities for active industry engagement. ~~This platform has not been designed nor is it intended to be used to direct registered entity operations.~~

The Situation Awareness department also provides funding to support the North American Synchro-Phasor Initiative (NASPI), which was initiated following the August 14, 2003 Northeast blackout. These devices can provide system operators with a critical indication of the health of the bulk power system and help predict weakened areas of the system. A number of phasor measuring devices have been installed in the interconnections and data concentrators have been put in place. In 2010, NERC entered into a contract with the Grid Protection Alliance (GPA) to further advance and support the development and deployment of synchro-phasor technologies. In 2011, NERC and GPA entered into a contract amendment which provides that a portion of NERC's funding commitment will be used to support work GPA was awarded by the Department of Energy (DOE) in December 2010, to develop a secure information exchange gateway for electric grid operations (the "SIEGate Grant"). This is in keeping with NERC's strategy to promote additional third-party funding of NASPI and leverage NERC's investments where practical. In addition to DOE funding, other entities are also providing funding support permitting NERC to further leverage NERC's NASPI investment. The primary objective of this project is to develop a secure and flexible "appliance" that will serve as the gateway for all

[31] Participating Reliability Coordinators included the NY-ISO, TVA, MISO, FRCC, ISO-NE, VACAR-S, Duke Energy, VACAR-S, SCE&G/SCANA, VCAR-S, SCPA/Santee Cooper, Southeastern RC, ERCOT, PJM, SPP&ICTE and WECC.

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types of real-time data exchanged between a utility control center and other control centers, utilities, and regulatory and oversight entities. NERC expects to conclude its funding of GPA by the end of 2013.

The Situation Awareness budget also includes funding for a number of reliability tools. The following is a further description of these tools.

- **Interchange Distribution Calculator (IDC)** — Used by reliability coordinators to manage interchange transactions and their curtailment during congestion on the bulk power system. NERC's primary role has been to incubate this tool to its present stage of commercial use by servinge as an interface between the IDC users and the vendor which owns, operates and maintains the IDC regarding modifications to the IDC software and services, as well as to pay the third party vendor for the costs of operating and maintaining the IDC. NERC does not use the IDC to conduct its operations. With the support of NERC's Standards Oversight and Technology Committee, NERC has provided the IDC vendor with written notice that it will not be renewing the IDC contract when it expires on March 31, 2013. NERC and a consortium of IDC users have begun the process of developing a transitional arrangement in which NERC would serve in the role of a billing agent for this group, who will assume the contractual obligations with OATI. An outline of the proposed billing agency structure is set for in Exhibit D.~~More detail regarding this proposed arrangement will be provided in the next draft of NERC's 2013 Business Plan and Budget.~~
- **Resource Adequacy (ACE Frequency) Tool** — Provides continuous monitoring of key resource adequacy performance metrics; including pre-established thresholds and limits defined in standards. Alerts Reliability Coordinators and resource subcommittees to critical inadequacies conditions such as major tie error, inaccurate load forecast and inadequate frequency response.
- **Inadvertent Interchange** — Facilitates the entering of monthly scheduling data and submittal of monthly inadvertent performance standards reports to NERC. It also assists in the monitoring and resolution of reliability issues originated by inadvertent interchange imbalances.
- **NERC Factor Viewer** — Allows transmission customers in the eastern interconnection to view factors related to information congestion.
- **System Data Exchange (SDX)** — Central repository of all scheduled and ongoing generator and transformer outages throughout the eastern interconnection. Provides input to the IDC.
- **Book of Flowgates** — A compendium of flowgates in the Eastern Interconnection and input to the IDC. NERC supports this tool by facilitating certain industry working groups and providing funding to support the development and operations of the book of flowgates by Open Access Technologies as part of the IDC contract described further below.

- **AIE Monitoring Tool** — An automatic data collection tool for post analysis of frequency excursions. It is used in major system disturbances as part of the frequency response analysis.
- **Frequency Monitoring and Analysis Tool** — Detects frequency events and captures key frequency response information for each interconnection.
- **Intelligent Alarms Tool** — Detects short-term and long-term frequency deviations ~~according to~~ using data transmitted to NERC by the Balancing Authorities. When coupled with the FNet[32] and Frequency Monitoring and Analysis tools, this tool allows for immediate differentiation of the cause of a frequency deviation – a generator trip or a scheduling error.

### 2013 Goals and Deliverables

- Ongoing SAFNR support of FERC, Regional Entity and stakeholder needs
- Respond to increased number of occurrences requiring analysis
- Managing a consistent program for issuing NERC alerts

### Resource Requirements

#### Personnel

No additional personnel are projected for this group during 2013. The reduction in FTEs ~~and~~is due to the elimination of the chief reliability officer position and support staff which was partially allocated to this department in 2012.

#### Contractor Expenses

The overall funding of approximately $2.5~~4~~M for contractors and consultants to support the Situation Awareness department in 2013 is approximately $1.1~~2~~M below 2012 budget levels, primarily due to the termination of the IDC Contract at the end of March 2013. Approximately $460k of the $2.4M budget is for IDC contract costs prior to contract termination and approximately $300k is for NERC's share of the cost of a secure third party communications network used to support situation awareness capabilities. The balances of the costs are to support various situation awareness needs, as well as NASPI funding. A detailed breakdown of the 2013 contractor and consulting budget is included in Exhibit B, together with a comparison to 2012 budgeted amounts.

Commencing in May 2013, NERC will provide a transitional billing service for the IDC users group, subject to FERC approval of the proposed billing services arrangement. Further details regarding this proposed arrangement will be set forth in the next draft of NERC's Business Plan and Budget.

[32] **FNet** – Operated by the Power Information Technology Laboratory at the University of Tennessee, FNET is a low-cost, quickly deployable GPS-synchronized wide-area frequency measurement network. High dynamic accuracy Frequency Disturbance Recorders (FDRs) are used to measure the frequency, phase angle, and voltage of the power system at ordinary 120 V outlets. The measurement data are continuously transmitted via the Internet to the FNET servers hosted at the University of Tennessee and Virginia Tech.

**Statement of Activities, Fixed Assets Expenditures and Change in Working Capital**
**2012 Budget & Projection, and 2013 Budget**
**SITUATION AWARENESS**

| | 2012 Budget | 2012 Projection | Variance 2012 Projection v 2012 Budget Over(Under) | 2013 Budget | Variance 2013 Budget v 2012 Budget Over(Under) | 2013 Budget Draft 1 | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|---|---|
| **Funding** | | | | | | | |
| **ERO Funding** | | | | | | | |
| NERC Assessments | $ 6,974,096 | $ 6,974,096 | $ - | $ 4,817,831 | $ (2,156,265) | $ 4,892,353 | $ (74,521) |
| Penalty Sanctions | - | - | - | 116,589 | 116,589 | 116,589 | - |
| **Total NERC Funding** | $ 6,974,096 | $ 6,974,096 | $ - | $ 4,934,420 | $ (2,039,676) | $ 5,008,942 | $ (74,521) |
| Membership Dues | - | - | - | - | - | - | - |
| Testing Fees | - | - | - | - | - | - | - |
| Services & Software | - | 5,060 | 5,060 | - | - | - | - |
| Workshops | - | 53,700 | 53,700 | 105,000 | 105,000 | - | 105,000 |
| Interest | 3,902 | 3,902 | - | 967 | (2,935) | 967 | - |
| Miscellaneous | - | - | - | - | - | - | - |
| **Total Funding (A)** | $ 6,977,998 | $ 7,036,758 | $ 58,760 | $ 5,040,387 | $ (1,937,611) | $ 5,009,908 | $ 30,479 |
| **Expenses** | | | | | | | |
| **Personnel Expenses** | | | | | | | |
| **Salaries** | $ 1,029,015 | $ 799,315 | $ (229,700) | $ 848,531 | $ (180,484) | $ 861,336 | (12,805) |
| **Payroll Taxes** | 68,901 | 54,698 | (14,203) | 58,110 | (10,791) | 58,296 | (186) |
| **Benefits** | 131,509 | 74,538 | (56,971) | 103,116 | (28,393) | 103,116 | - |
| **Retirement Costs** | 142,882 | 83,795 | (59,087) | 99,442 | (43,440) | 99,442 | - |
| **Total Personnel Expenses** | $ 1,372,307 | $ 1,012,346 | $ (359,961) | $ 1,109,199 | $ (263,108) | $ 1,122,190 | (12,991) |
| **Meeting Expenses** | | | | | | | |
| **Meetings** | $ 104,570 | $ 158,270 | $ 53,700 | $ 198,000 | $ 93,430 | $ 104,570 | 93,430 |
| **Travel** | 131,000 | 131,000 | - | 72,500 | (58,500) | 131,000 | (58,500) |
| **Conference Calls** | 24,175 | 24,175 | - | 24,175 | - | 24,175 | - |
| **Total Meeting Expenses** | $ 259,745 | $ 313,445 | $ 53,700 | $ 294,675 | $ 34,930 | $ 259,745 | 34,930 |
| **Operating Expenses** | | | | | | | |
| **Consultants & Contracts** | $ 3,588,116 | $ 3,950,764 | $ 362,648 | $ 2,493,180 | $ (1,094,936) | $ 2,429,504 | 63,676 |
| **Office Rent** | - | - | - | - | - | - | - |
| **Office Costs** | 50,950 | 12,000 | (38,950) | 47,750 | (3,200) | 95,951 | (48,201) |
| **Professional Services** | - | 7,728 | 7,728 | 180 | 180 | - | 180 |
| **Miscellaneous** | 1,500 | 1,500 | - | 1,000 | (500) | 1,500 | (500) |
| **Depreciation** | 47,853 | 43,952 | (3,901) | 7,395 | (40,458) | 47,853 | (40,458) |
| **Total Operating Expenses** | $ 3,688,419 | $ 4,015,944 | $ 327,525 | $ 2,549,505 | $ (1,138,914) | $ 2,574,808 | $ (25,303) |
| **Total Direct Expenses** | $ 5,320,471 | $ 5,341,735 | $ 21,264 | $ 3,953,379 | $ (1,367,092) | $ 3,956,743 | $ (3,364) |
| **Indirect Expenses** | $ 1,777,691 | $ 1,102,969 | $ (674,722) | $ 1,080,012 | $ (697,678) | $ 1,073,164 | $ 6,848 |
| **Other Non-Operating Expenses** | $ - | $ - | $ - | $ - | $ - | $ - | - |
| **Total Expenses (B)** | $ 7,098,161 | $ 6,444,703 | $ (653,458) | $ 5,033,391 | $ (2,064,770) | $ 5,029,907 | $ 3,484 |
| **Change in Assets** | $ (120,163) | $ 592,055 | $ 712,218 | $ 6,996 | $ 127,159 | $ (19,999) | 26,994 |
| **Fixed Assets** | | | | | | | |
| Depreciation | (47,853) | (43,952) | 3,901 | (7,395) | 40,458 | (47,853) | 40,458 |
| Computer & Software CapEx | - | - | - | - | - | - | - |
| Furniture & Fixtures CapEx | - | - | - | - | - | - | - |
| Equipment CapEx | - | - | - | - | - | - | - |
| Leasehold Improvements | - | - | - | - | - | - | - |
| Allocation of Fixed Assets | $ (72,310) | $ (22,786) | 49,524 | 14,391 | 86,701 | $ 27,854 | (13,464) |
| **Inc(Dec) in Fixed Assets ( C )** | $ (120,163) | $ (66,738) | $ 53,425 | $ 6,996 | $ 127,159 | $ (19,999) | $ (40,458) |
| **TOTAL BUDGET (=B + C)** | $ 6,977,998 | $ 6,377,965 | $ (600,033) | $ 5,040,387 | $ (1,937,611) | $ 5,009,908 | |
| **TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)** | $ (0) | $ 658,793 | $ 658,793 | $ - | $ 0 | $ - | $ - |
| **FTEs** | 8.17 | 6.15 | (2.02) | 6.50 | (1.67) | 6.50 | - |

## Summary of Variances by Category – 2013 Budget Compared to the 2012 Budget

- Personnel Expenses – The decrease is due to the 1.67 reduction in FTEs in the department.
- Meetings Expenses – Includes the cost of NASPI workshops, which are offset by $105k in projected Workshop Fees, and the cost of quarterly OC-PC meetings.
- Consultants and Contracts – The decrease is due to the termination of the IDC contract as described above.

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## Event Analysis and Investigations

| Events Analysis and Investigations (in whole dollars) | 2012 Budget | 2013 Budget | Increase (Decrease) | 2013 Budget -Prior Draft | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|
| Total FTEs | 13.00 | 15.50 | 2.50 | 15.50 | - |
| Direct Expenses | $ 3,118,744 | $ 3,352,319 | $ 233,576 | $ 3,452,932 | $ (100,613) |
| Indirect Expenses | $ 2,041,732 | $ 2,575,414 | $ 533,682 | $ 2,559,084 | $ 16,330 |
| Other Non-Operating Expenses | $ - | $ - | $ - | | $ - |
| Inc(Dec) in Fixed Assets | $ (85,127) | $ 34,316 | $ 119,443 | $ 66,422 | $ (32,106) |
| Total Funding Requirement | $ 5,075,349 | $ 5,962,049 | $ 886,700 | $ 6,078,438 | $ (116,389) |

### Background and Scope

The Event Analysis and Investigation Group is comprised of highly qualified technical staff which performs quality reviews of all event analysis reports submitted to NERC, ~~capture~~collects and evaluates metrics and trends. The analysis effort requires in-depth technical reviews and is also used to develop lessons learned and alerts.

This department is critical to supporting the ERO's reliability goals through its work to evaluate bulk power system events, undertaking appropriate levels of analysis to determine the causes of the events, promptly assuring tracking of corrective actions to prevent recurrence, and providing lessons learned to the industry. The primary responsibilities of this department are divided between two separately staffed groups: (1) the event analysis group and (2) the event investigation group. The event analysis group is responsible for directing all NERC activities with respect to event analysis, assuring consistent, timely, and coordinated results, as well as interfacing with regulatory authorities, Regional Entities, industry and stakeholder committees, registered entities, and other ~~focus~~ groups regarding event analysis and compliance investigations. The event investigation group is responsible for reviewing formal complaints and conducting non-public compliance investigations, as well as assisting in the review of registered entity compliance assessments.

### 2013 Goals and Deliverables

- Use of more sophisticated cause codes for analysis.
- Refinement of risk-based methodologies to support more effective and efficient identification of reliability risks.
- Provide timely publication of lessons learned and recommendations and track responses to recommendations.
- Refine the criteria and process for self-analysis of events and disturbances to promote continuous improvement and information sharing.

## Resource Requirements

### Personnel

One additional position was added in 2012 to support the identification of emerging reliability risks and development of risk control strategies. The remaining increase in FTEs is the result of transferring the Human Performance function from another program area and the full year ~~a~~effect of one position added in 2012, but budgeted as 0.5 FTE.

### Contractor Expenses

Consulting and contractor expenses for this department are primarily related to the retention of subject matter experts to assist in the event analysis program, as well as ongoing investigations. Examples of situations ~~which arise~~ which have required the retention of additional outside consulting resources include the September 8, 2011 Southwest Outage event and the February 1-5 2011 Cold Snap event. $120k is projected for contractors and consultants for 2013 which is consistent with the 2012 budget. To the extent events arise requiring the use of additional experts, funding will be provided from working capital reserves as further described in management's proposed working capital and contingency operating reserve policy and guidelines.

## Human Performance Function

### Background and Scope

NERC's Human Performance program goal is to help reduce human error and those precursory factors that allow human error to impact system reliability. In support of this goal, this group is focused on information sharing and training through conferences, workshops, webinars, and publications and facilitated active sharing among NERC and its stakeholders. Human performance fundamentals will play an important role in supporting compliance and standards training initiatives, as well as supporting trending and analysis to identify emerging trends which are reliability risks to the bulk power system.

On January 7, 2011, NERC announced a preliminary set of high priority reliability issues intended to focus ERO program areas, including standards setting, compliance, and training and education.[33] Three of these eight high priorities are directly linked with human performance. Over 74% of the contributing causes of events on the BPS are related to human performance error (from individual to organizational), with 44% of this error being the actual root cause. The addition of a human factors engineer on staff has allowed NERC to directly address some of these threats to BPS reliability. Human Performance evaluations conducted during the event analysis process is providing valuable insight into why events are occurring and how they can be prevented in the future. The NERC human performance initiative has been instrumental in the understanding, analysis, and subsequent identification of the risk-based controls and strategies for improving reliability.

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[33] ***NERC President's Top Priority Issues for Bulk Power System Reliability,*** http://www.nerc.com/news_pr.php?npr=723 at http://www.nerc.com/fileUploads/File/News/NERC%20President%20Top%20Priority%20BPS%20Reliability%20Issues%201-7-11.pdf

The NERC Improving Human Performance on the Grid Conference in March of 2012 was a testament to the need for a North American initiative as over 200 industry personnel representing over 100 registered entities attended the three day conference and workshop, which included a one day class on cause analysis training. A direct result of this large gathering of industry human performance personnel and trainers, a proposal has been submitted to the NERC Operating Committee to form a Human Performance Subcommittee. NERC is still receiving positive feedback and industry support from the conference and associated workshop. The selected comments below are from industry personnel that attended the conference and left feedback:

- *"NERC has come so far as an organization. This conference is the first that clearly reflected NERC's role in providing valuable guidance towards improving system reliability."*
- *"Outstanding conference! Most likely the best I've attended in over 30 years in this industry. Thank you!!"*
- *"Make the conference an annual event."*
- *"Start an HP work group."*
- *"Great info to take back and build an implementation plan for a company where this initiative is in its infancy."*
- *"Bringing the industry together for a common goal of improving human performance."*

The NERC human performance initiative continues to collaborate with industry human performance projects such as the Western Electricity Coordinating council's Human Performance Working Group, the North American Transmission Forum's Human Performance Group and the Electric Power Research Institute.

NERC's Training, Education and Operator Certification Department budget includes training opportunities to increase awareness, knowledge and skills on human performance fundamentals; including web based training development for ERO staff and/or industry on industry human performance fundamentals. NERC's training efforts will also focus on knowledge and skills development in a number of key areas, including human performance error reduction techniques, which may include workshops, webinars and participation in industry training events.

## 2013 Goals and Key Deliverables

- Conduct semi-annual three-day ERO Human Performance workshops which.
- Facilitate the transfer of information in terms of best practices, lessons learned and industry innovations in the area of human performance to include possible routine publications and notices.
- Continue to identify opportunities and methods for improvement based on proven methods from other industries and continue to lead an industry-wide program to improve human performance components of bulk power system reliability.

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**Resource Requirements**

As previously described, NERC's 2013 budget includes resources associated with a human performance function which was established by NERC in 2011. Resources associated with this function are budgeted within the Event Analysis and Investigations department. The workshops are expected to operate close to a breakeven basis.

**Statement of Activities, Fixed Assets Expenditures and Change in Working Capital**
**2012 Budget & Projection, and 2013 Budget**
**EVENTS ANALYSIS and INVESTIGATIONS**

| | 2012 Budget | 2012 Projection | Variance 2012 Projection v 2012 Budget Over(Under) | 2013 Budget | Variance 2013 Budget v 2012 Budget Over(Under) | 2013 Budget Draft 1 | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|---|---|
| **Funding** | | | | | | | |
| **ERO Funding** | | | | | | | |
| NERC Assessments | $ 5,073,333 | $ 5,073,333 | $ 0 | $ 5,629,724 | $ 556,391 | $ 5,798,113 | $ (168,389) |
| Penalty Sanctions | - | $ - | | 278,020 | 278,020 | 278,020 | - |
| **Total NERC Funding** | **$ 5,073,333** | **$ 5,073,333** | **$ 0** | **$ 5,907,744** | **$ 834,412** | **$ 6,076,133** | **$ (168,389)** |
| Membership Dues | - | - | - | - | - | - | - |
| Testing Fees | - | - | - | - | - | - | - |
| Services & Software | - | - | - | - | - | - | - |
| Workshops | - | 63,000 | 63,000 | 52,000 | 52,000 | - | 52,000 |
| Interest | 2,016 | 2,408 | 392 | 2,305 | 289 | 2,305 | - |
| Miscellaneous | - | - | - | - | - | - | - |
| **Total Funding (A)** | **$ 5,075,349** | **$ 5,138,741** | **$ 63,392** | **$ 5,962,049** | **$ 886,701** | **$ 6,078,438** | **$ (116,389)** |
| **Expenses** | | | | | | | |
| **Personnel Expenses** | | | | | | | |
| **Salaries** | $ 1,943,198 | $ 2,125,583 | $ 182,385 | $ 2,236,180 | $ 292,982 | $ 2,269,643 | (33,463) |
| **Payroll Taxes** | 125,163 | 132,653 | 7,490 | 140,844 | 15,681 | 141,339 | (495) |
| **Benefits** | 212,843 | 175,892 | (36,951) | 206,818 | (6,025) | 206,818 | - |
| **Retirement Costs** | 278,926 | 232,271 | (46,655) | 261,518 | (17,408) | 261,518 | - |
| **Total Personnel Expenses** | **$ 2,560,130** | **$ 2,666,399** | **$ 106,269** | **$ 2,845,360** | **$ 285,230** | **$ 2,879,318** | **(33,958)** |
| **Meeting Expenses** | | | | | | | |
| **Meetings** | $ 10,000 | $ 66,584 | $ 56,584 | $ 62,000 | $ 52,000 | $ 25,000 | 37,000 |
| **Travel** | 395,000 | 395,000 | - | 270,000 | (125,000) | 395,000 | (125,000) |
| **Conference Calls** | - | 24,000 | 24,000 | - | - | - | - |
| **Total Meeting Expenses** | **$ 405,000** | **$ 485,584** | **$ 80,584** | **$ 332,000** | **$ (73,000)** | **$ 420,000** | **(88,000)** |
| **Operating Expenses** | | | | | | | |
| **Consultants & Contracts** | $ 120,000 | $ 130,000 | $ 10,000 | $ 120,000 | $ - | $ 120,000 | - |
| **Office Rent** | - | - | - | - | - | - | - |
| **Office Costs** | 31,614 | 48,000 | 16,386 | 53,524 | 21,910 | 31,614 | 21,910 |
| **Professional Services** | - | 438 | 438 | 435 | 435 | - | 435 |
| **Miscellaneous** | 2,000 | 667 | (1,333) | 1,000 | (1,000) | 2,000 | (1,000) |
| **Depreciation** | - | - | - | - | - | - | - |
| **Total Operating Expenses** | **$ 153,614** | **$ 179,105** | **$ 25,491** | **$ 174,959** | **$ 21,345** | **$ 153,614** | **$ 21,345** |
| **Total Direct Expenses** | **$ 3,118,744** | **$ 3,331,087** | **$ 212,344** | **$ 3,352,319** | **$ 233,575** | **$ 3,452,932** | **$ (100,613)** |
| **Indirect Expenses** | **$ 2,041,732** | **$ 2,645,331** | **$ 603,599** | **$ 2,575,414** | **$ 533,682** | **$ 2,559,084** | **$ 16,330** |
| **Other Non-Operating Expenses** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |
| **Total Expenses (B)** | **$ 5,160,476** | **$ 5,976,419** | **$ 815,943** | **$ 5,927,733** | **$ 767,257** | **$ 6,012,016** | **$ (84,283)** |
| **Change in Assets** | **$ (85,127)** | **$ (837,678)** | **$ (752,551)** | **$ 34,316** | **$ 119,443** | **$ 66,422** | **(32,106)** |
| **Fixed Assets** | | | | | | | |
| Depreciation | - | - | - | - | - | - | - |
| Computer & Software CapEx | - | - | - | - | - | - | - |
| Furniture & Fixtures CapEx | - | - | - | - | 0 | - | - |
| Equipment CapEx | - | - | - | - | 0 | - | - |
| Leasehold Improvements | - | - | - | - | 0 | - | - |
| Allocation of Fixed Assets | $ (85,127) | $ (54,650) | 30,477 | 34,316 | 119,443 | $ 66,422 | (32,106) |
| **Inc(Dec) in Fixed Assets ( C )** | **$ (85,127)** | **$ (54,650)** | **$ 30,477** | **$ 34,316** | **$ 119,443** | **$ 66,422** | **$ (32,106)** |
| **TOTAL BUDGET (=B + C)** | **$ 5,075,349** | **$ 5,921,768** | **$ 846,420** | **$ 5,962,049** | **$ 886,700** | **$ 6,078,438** | **$ (116,389)** |
| **TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)** | **$ (0)** | **$ (783,027)** | **$ (783,027)** | **$ -** | **$ 0** | **$ -** | **$ -** |
| **FTEs** | **13.00** | **14.75** | **1.75** | **15.50** | **2.50** | **15.50** | **-** |

## Summary of Variances by Category – 2013 Budget Compared to the 2012 Budget

- Personnel Expenses – The increase in Salaries and Payroll Taxes is due to the 2.5 increase in FTEs in the department. Lower average costs per FTE for Benefits and Retirement due to changes to NERC's employee benefit and retirement plans resulted in lower projected costs in 2013.

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- Meetings expense includes the projected cost of the Human Performance Workshop, which is offset by projected funding from Workshop Fees.

## Critical Infrastructure Department

**[Note to reader- significant edits were made to this section of the business plan and budget, which resulted in significant and somewhat difficult to track redlining in the marked version of the document compared to draft 1. We therefore made the decision to replace the entire text of this section of the document. The replaced text follows the strike out of the previous text for this section. Budget changes from the prior draft have been noted where applicable.]**

| Critical Infrastructure Department (in whole dollars) | 2012 Budget | 2013 Budget | Increase (Decrease) | 2013 Budget - Prior Draft | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|
| Total FTEs | 17.00 | 19.25 | 2.25 | 19.25 | - |
| Direct Expenses | $ 5,214,260 | $ 5,143,207 | $ (71,053) | $ 5,102,315 | $ 40,892 |
| Indirect Expenses | $ 2,274,398 | $ 3,198,498 | $ 924,100 | $ 3,178,217 | $ 20,281 |
| Other Non-Operating Expenses | $ - | $ - | $ - | | $ - |
| Inc(Dec) in Fixed Assets | (92,510) | 42,618 | 135,128 | 82,492 | (39,874) |
| Total Funding Requirement | $ 7,396,148 | $ 8,384,323 | $ 988,175 | $ 8,363,024 | $ 21,299 |

~~**Background and Scope**~~

~~The Critical Infrastructure Department (CID) supports critical infrastructure protection (CIP) standards initiatives, the Compliance Operations department's audit oversight function, CIP and cyber information sharing, incident analysis, alerts, system-level risk assessment, and enhanced coordination between industry and our governmental partners.~~

~~**2013 Goals and Deliverables**~~

- ~~Support the Standards Program area in CIP standards development.~~
- ~~Support the Compliance Operations department in its oversight of Regional Entity CMEP audits.~~
- ~~Continue to enhance the ES-ISAC program, which was first deployed over 10 years ago. ES-ISAC functions will include a portal for bi-directional information sharing with government and industry, rapid dissemination of threat and vulnerability information across the industry, a secure repository for security guidelines, incident, threat, and vulnerability information, and an analytical capability to assess potential risks to reliability and develop mitigations for industry consideration.~~
- ~~Continue to collaborate with government agencies in the United States and Canada to develop more timely dissemination of classified information regarding threats to the bulk power system, including dissemination of information from classified sources in a form that can be provided to and used by the industry.~~

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- Working jointly with Regional Entities, increase the transparency of CIP compliance processes and program results among regions by deploying shared procedures, training and tools; improve risk-based approaches for CIP auditing to optimize resource utilization; and promote a culture of compliance excellence through education, information, and consistency.
- Work with the Compliance Operations department and the Regional Entities to ensure efficient monitoring of compliance with CIP standards by registered entities.
- Conduct security incident analysis and work with industry experts to evaluate, track, and identify lessons learned and security metrics that enhance the sector's security posture.
- Provide support to the Critical Infrastructure Protection Committee (CIPC), CIP Compliance Working Group, Electricity Sub-Sector Coordinating Council, and working groups and task forces serving the Standing Committees.
- Provide support to bulk power system entities in development of adequate cyber risk preparedness exercises.
- Apply resources to improve education and outreach related to both CIP standards compliance and general security risk management.

  Host four CIP auditor workshops in 2013 and work jointly with the Compliance Operations department to improve auditor training materials and programs.

**Standards Support**

A single version of the CIP Standards is in effect, with action moving forward for both Version 4, as well as the continued development of Version 5 of the standards. The ERO continues to engage industry in efforts for compliance with Version 3, looking toward the implementation of Version 4 and Version 5 through outreach presentations, webinars, and other training opportunities. NERC also began conducting training and outreach to the regional audit staff for audit approaches to both Version 4 and Version 5.

CID has started outreach efforts with Version 4 and will continue into 2013. CID plans to conduct multiple webinars outlining Version 4 differences and updates. Version 4 of the CIP Reliability Standards, which includes bright-line criteria, provides a specific list of assets for entities to consider critical, rather than having each entity develop a methodology to determine its critical assets. This significant accomplishment enables entities to more efficiently and effectively identify Critical Cyber Assets and deploy appropriate controls to protect those assets.

CID continues to conduct the Sufficiency Review Program (SRP), an outreach program to registered entities that examines the Risk Based Assessment Methodology (RBAM) that is required by CIP-002-3. The SRP examines whether an entity's RBAM is sufficient to properly identify the Critical Assets and Critical Cyber Assets that ensure the safe, reliable operation of the BPS. CID is scheduled to conduct 10 SRPs in 2013.

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In the standards development area, the ERO continued the development of "Version 5" of the CIP Standards throughout the year. While the main focus of Version 5 development continues to address all the remaining FERC Order No. 706 directives, Version 5 contains several other changes based on practical experiences from both registered entities and ERO audit staffs.

**Support of Regional Entity Audit Oversight**

CID supports the efforts of NERC's Compliance Operations department and the Regional Entities to improve the consistency of compliance program results, improve risk-based approaches for auditing and spot checking, and promote a culture of security and compliance through education, transparency, and incentives.

CID plans to continue to increase its CIP audit oversight in 2013. With the personnel resources added in 2012 and the requested personnel for 2013, CID's projected goal is to achieve oversight on approximately 20 percent of ERO CIP Audits in 2013.

In addition to the assigned CIP oversight audits of Regional Entities, the NERC CIP auditors are engaged with the following programs and initiatives:

- Managing the Technical Feasibility Exception (TFE) program, to include interface with the regional TFE managers and preparation of the annual report to FERC;
- Coordinating and planning CIP auditor workshops;
- Facilitating and providing administrative support to the CIP Compliance Working Group;
- Providing CIP subject matter expert presentations to regional compliance workshops;
- Providing CIP subject matter expertise and compliance liaison to the Cybersecurity 706 Standard Drafting Team;
- Providing CIP subject matter expertise to the Situational Awareness for FERC, NERC, and the Regions program;
- Providing subject matter expertise to NERC Event Analysis and Investigations;
- Providing CIP subject matter expertise in response to queries from industry and the public, as submitted via NERC's web site; and
- Participating as a liaison for CIP compliance issues/concerns during weekly NERC/FERC status conferences.

**ES-ISAC**

ISACs represent the nexus of focused effort designed to meet these cross-sector information sharing requirements. The ES-ISAC gathers information from the disparate electricity industry participants about security-related events, disturbances, and off-normal occurrences within the Electricity Sub-sector and shares that information with its partners in the government. In turn, the government provides information regarding risks, threats, and warnings to the ES-ISAC, which is responsible for disseminating that information throughout the Electricity Sub-sector.

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~~In general, the two functions that the ES-ISAC supports, Information Sharing and Analytics, are vitally important to all other Critical Infrastructures and Key Resource Sectors (CIKR) that have active ISACs. Effective collaboration and communication is essential to addressing infrastructure protection and resilience within each sector, as well as the important interdependencies that exist among sectors. ISACs represent the nexus of focused effort designed to meet these cross-sector information sharing requirements.~~

~~The ES-ISAC operates under the authority set forth in §1003 of the Rules of Procedure which state:~~

- ~~NERC shall encourage and participate in coordinated Critical Infrastructure protection exercises, including interdependencies with other Critical Infrastructure sectors.~~
- ~~NERC shall improve methods to better assess the impacts of a possible physical attack on the Bulk Power System and means to deter, mitigate, and respond following an attack.~~

~~The ES-ISAC gathers information from the disparate electricity industry participants about security related events, disturbances, and off-normal occurrences within the Electricity Sub-sector and shares that information with its partners in the government. In turn, the government provides information regarding risks, threats, and warnings to the ES-ISAC, which is responsible for disseminating that information throughout the Electricity Sub-sector. In general, the two functions that the ES-ISAC supports, Information Sharing and Analytics, are vitally important to all other Critical Infrastructures and Key Resource Sectors (CIKR) that have active ISACs. Effective collaboration and communication is essential to addressing infrastructure protection and resilience within each sector, as well as the important interdependencies that exist among sectors. The ES-ISAC, operating within the requirements of ROP Section 810, is authorized to develop and distribute Alerts and Notifications. These Alerts and Notifications are divided into three different levels: Level 1, Industry Advisory; Level 2, Recommendation to Industry; Level 3, Essential Actions; Level 2 and Level 3 Alerts and Notifications bear a mandatory response requirement from the BPS entities as defined under the requirements of the ROP Section 810. This mandatory response is unique since no other ISAC has an obligatory response mechanism and their Alerts are considered a "Fire and Forget" type of alerting mechanism.~~

~~In addition to Alerts and Notifications, the ES-ISAC has the ability to request data or information from Registered Entities. In section 1600 of the ROP, NERC outlines the Registered Entities' obligations to respond to data requests. Using this authority, the ES-ISAC may mandate Registered Entities' response to information requests that the ES-ISAC deems necessary to support its analytical functions or reduce BPS risk. Section 1600 also provides expedited procedures for requesting time-sensitive data or information.~~

~~The ES-ISAC is also leveraging its private portal to receive voluntary reports from industry members. This volunteering and open collaboration is the primary means the ES-ISAC uses to engage the industry on a daily basis.~~

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~~Due to its formal role within the NIPP, the ES-ISAC enjoys a special relationship with DHS. The ES-ISAC maintains an integration capability on the operations floor of the National Cybersecurity and Communications Integration Center (NCCIC). This Top Secret, real-time, operations center is the hub for classified threat and vulnerability work, and the ES-ISAC plays a central role in this operation. This NCCIC floor is where the ES-ISAC cleared personnel analyze the threat and vulnerability components seen by the intelligence community and make an initial determination of potential impacts that the BPS may experience. The NCCIC also serves as a means to allow the ES-ISAC to provide subject matter expertise for matters of defense mission assurance, nuclear, oil, and natural gas, and water as it pertains to the national and continental security interests.~~

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~~The ES-ISAC also has built other relationships with both the United States and Canadian governments. This includes Department of Energy (DoE), Canadian Secret Intelligence Service, and Department of Defense.~~

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~~In 2011, the ES-ISAC took several steps to begin building out the ES-ISAC, including hiring key technical staff to support information sharing and analysis efforts and contracting with organizations to provide the data and mechanisms necessary to conduct these activities. In 2012, the ES-ISAC is implementing the tools, techniques, and procedures needed to support its information sharing and information analysis functions. These two functions support a detailed understanding of emerging threats to the grid, vulnerabilities of various grid components, bi-directional information flow, and important mitigation actions. Combined, these two functions of the ES-ISAC support the primary NERC mission, which is to ensure the reliability of the North American Bulk Power System by understanding emergent risks and providing a platform to support active mitigation of these risks.~~

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**~~2013 Resource Requirements~~**

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**~~Personnel~~**

~~CID will have a total of four CIP auditors on staff at the end of 2012. To support projected increases in workload in connection with NERC audit oversight activities, transition to CIP Standards version 4, increased oversight activities, and additional ERO activities the CIP auditors support, CID proposes to add two additional CIP auditors in 2013. In addition, a Cyber Security Specialist will also be added to the ES-ISAC team to research, analyze, and disseminate information regarding significant cyber and physical security incidents, as well as conduct security-focused risk management and security incident reporting analysis. The Cyber Security Specialist will also support the ES-ISAC with event and incident data analysis, conducting analysis of all security related incidents, and continue the development of incident descriptions, categories, and measurements. Finally, this individual will support access to operations center positions in the ICS-CERT and at the DHS National Incident Coordination Center in Washington, DC. This resource is required to stand watch on the NCCIC floor on a rotating schedule. The 2.25 FTEs in the chart at the beginning of this section is due to projected phasing and timing of hires.~~

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**Contractors and Consultants**

The total projected 2013 CID contractor and consulting budget is $845k. The following is a description of the major areas of contractor and consulting support. A detailed breakdown of 2013 budgeted costs is set forth in Exhibit B, with a comparison to 2012.

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- Electricity Sub-sector Coordinating Council (ESCC) Support CID manages the ESCC, which was established under the NIPP framework to foster and facilitate the coordination of sector-wide policy-related activities and initiatives to improve the reliability and resilience of the Electricity Sub-sector, including physical and cyber security infrastructure. The ESCC, which consists of senior level sector leaders, developed a Critical Infrastructure Strategic Roadmap, which includes an action plan to address certain severe impact risks to electricity system reliability. NERC contracted with an industry expert to assist NERC in its support of the ESSC.
- GridEx 2013 Support an exercise designed to validate the readiness of the Electricity Sub-sector to respond to a security incident (CIP-008), strengthen utilities' crisis response functions, and provide input for internal security program improvements. This bi-annual exercise focuses solely on disruptions and recovery (CIP-009) to the Electricity Sub-sector and includes subject matter experts from government and industry.
- 2013 ES-ISAC Members Conference The ES-ISAC is planning a one-day conference in conjunction with NERC's 2013 Grid Security Conference. The purpose of this conference is to focus on the operational aspects of the ES-ISAC by sharing with entities the types of information the ES-ISAC receives from data feeds and other security partners, demonstrating tools the ES-ISAC and other security companies use to track and analyze data, and conducting security training on issues, vulnerabilities, and best practices.
- ES-ISAC – Secure Portal The ES-ISAC portal build-out is underway in 2012 and includes a private, members-only portal to disseminate security information to members and to serve as collaboration "zones." Some of the planned zones include: a notification center (an exclusive zone for sharing of indicators of compromise); collaboration zones for groups such as Hydra (a technical subject matter expertise group) and the various NERC task forces; and an Alerts and Notification center to allow for non-registered entities to access the products. The members' portal component will be segregated from the compliance and enforcement programs of NERC and include a variety of information sharing mechanisms. The portal build-out will allow for bi-directional information sharing between the ES-ISAC and industry. Initial build-out costs were incurred in 2012 and maintenance costs will be required in 2013.
- ES-ISAC – Secure Connection to US-CERT for Bi-directional Information Sharing Some emergent situations allow for quick transmission of secure information between the ES-ISAC and DHS' United States Computer Emergency Readiness Team (US-CERT). This transmission occurs through formal and stringent technology requirements.
- Cyber Risk Preparedness Assessment (CRPA) The CRPA is a project designed to assess the current cyber resiliency capabilities of BPS entities and the adequacy of existing reliability mechanisms related to the unique nature of cyber threats. Through these

assessments, the ES-ISAC can target key areas for improvement and share areas of best practices with industry. The CRPA also provides the opportunity to educate participants and, through carefully defined deliverables, share effective practices and impart knowledge to all BPS entities. The cost to conduct a CRPA is based on contractor hourly fees, prepared materials, and travel expenses.

- Attack Tree Threat Modeling- Attack trees are hierarchical, graphical diagrams that show how low-level hostile activities interact and combine to achieve an adversary's objectives—usually with negative consequences for the attack victim. NERC contracted with a company that has developed an advanced attack tree-based threat risk assessment tool, which allows enterprises to discover which weaknesses are most likely to be used against them by attackers. This tool provides the results needed to justify security choices to company executives and security practitioners. The product is equally applicable to information technology and physical security.
- Reporting Services-ES-ISAC staff must maintain a detailed understanding of emerging vulnerabilities and threats affecting industrial control systems and the bulk power system. This service gives ES-ISAC staff increased understanding of continuing trends, breaking news, and implications to the BPS.
- Aurora webinars and reporting-NERC and the ES-ISAC have been working since 2007 to address the Aurora Vulnerability, a significant supply chain vulnerability that impacts digital protective control devices, which protect generators and motors in use throughout the bulk power system.

Analytic capabilities- A software service that provides cyber awareness and continuous monitoring, and helps organizations protect against targeted attacks by gathering, correlating, and analyzing threat information from within their own networks, supply chains, and the rest of the Internet. This tool provides real-time internet communications visibility and analytics.

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# Critical Infrastructure Department

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| Critical Infrastructure Department (in whole dollars) | 2012 Budget | 2013 Budget | Increase (Decrease) | 2013 Budget - Prior Draft | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|
| Total FTEs | 17.00 | 19.25 | 2.25 | 19.25 | - |
| Direct Expenses | $ 5,214,260 | $ 5,143,207 | $ (71,053) | $ 5,102,315 | $ 40,892 |
| Indirect Expenses | $ 2,274,398 | $ 3,198,498 | $ 924,100 | $ 3,178,217 | $ 20,281 |
| Other Non-Operating Expenses | $ - | $ - | $ - | | $ - |
| Inc(Dec) in Fixed Assets | (92,510) | 42,618 | 135,128 | 82,492 | (39,874) |
| Total Funding Requirement | $ 7,396,148 | $ 8,384,323 | $ 988,175 | $ 8,363,024 | $ 21,299 |

## Background and Scope

The Critical Infrastructure Department (CID) supports CIP standards initiatives, the Compliance Operations department's audit oversight function, CIP and cyber information sharing, incident

analysis, alerts, system-level risk assessment, and enhanced coordination between industry and our governmental partners.

## 2013 Goals and Deliverables

- Support the Standards Program area in CIP standards development
- Support the Compliance Operations department in its oversight of Regional Entity audits
- Continue ES-ISAC capability enhancement and information sharing through portal development and alignment with the broader ISAC community. ES-ISAC functions will include a portal for bi-directional information sharing with government and industry, rapid dissemination of threat and vulnerability information across the industry, a secure repository for security guidelines, incident, threat, and vulnerability information, and an analytical capability to assess potential risks to reliability and develop mitigations for industry consideration
- Additional portal capability to include zones to exchange Indicators of Compromise (IOC), asset owner and operator information, notifications and a security blog or collaborative environment. IOC formats will align with government source formats for "below the tear-line" dissemination to industry
- Continue to collaborate with government agencies in the United States and Canada to develop more timely dissemination of classified information regarding threats to the bulk power system, including dissemination of information from classified sources in a form that can be provided to and used by the industry
- Working jointly with Regional Entities, increase the transparency of CIP compliance processes and program results among regions by deploying shared procedures, training and tools; improve risk-based approaches for CIP auditing to optimize resource utilization; and promote a culture of compliance excellence through education, information, and consistency
- Conduct security incident analysis and work with industry experts to evaluate, track, and identify lessons learned and security metrics that enhance the sector's security posture
- Provide support to the Critical Infrastructure Protection Committee (CIPC), CIP Compliance Working Group, Electricity Sub-Sector Coordinating Council (ESSC), and working groups and task forces serving the Standing Committees
- Apply resources to improve education and outreach related to both CIP standards compliance and general security risk management
- Host four CIP auditor workshops in 2013 and work jointly with the Compliance Operations department to improve auditor training materials and programs
- Facilitate interactive events such as the annual Grid Security Conference (GridSecCon), the bi-annual Grid Exercise (GridEx), Cyber Risk Preparedness Assessments (CRPA), and the Sufficiency Review Program (SRP) to enhance sector training, awareness and security. Successfully support 10 SRPs and activities related to the voluntary White

House/DOE Electricity Sub-sector Cybersecurity Maturity Model with the existing CRPA engagement process

- Provide subject matter expertise and facilitation to Energy Security Public-Private Partnership Group, which is designed to address protected Defense-related mission assurance concerns
- Provide technical, process facilitation, and critical infrastructure security subject matter expertise to standards development efforts designed to reduce Directives, complete a Technical Reference Guide, and deliver CIP v.5 advancement
- Support efforts to reduce the NERC/CE Caseload Index and improve the enforcement case closure rate
- Offer technical security expertise to assist in system impact characterization and BPS risk for significant compliance violations, resulting in better informed BPS risk management practice development
- Foster technical development of risk-based compliance monitoring to maximize reliability benefits and internal controls
- Contribute technical expertise to establishment of a NERC enterprise-wide cause coding effort designed to inform sector risk based analytics
- Facilitate interactive training events such as the annual Grid Security Conference (GridSecCon) and the bi-annual Grid Security Exercise (GridEx)

**Standards Support**

A single version of the CIP Standards is in effect, with action moving forward for both Version 4, as well as the continued development of Version 5 of the standards. The ERO continues to engage industry in efforts for compliance with Version 3, looking toward the implementation of Version 4 and Version 5 through outreach presentations, webinars, and other training opportunities. NERC also began conducting training and outreach to the regional audit staff for audit approaches to both Version 4 and Version 5.

CID has started outreach efforts with Version 4 and will continue into 2013. CID plans to conduct multiple webinars outlining Version 4 differences and updates. Version 4 of the CIP Reliability Standards, which includes bright-line criteria, provides a specific list of assets for entities to consider critical, rather than having each entity develop a methodology to determine its critical assets. This significant accomplishment enables entities to more efficiently and effectively identify Critical Cyber Assets and deploy appropriate controls to protect those assets.

CID continues to conduct the Sufficiency Review Program (SRP), an outreach program to registered entities that examines the Risk Based Assessment Methodology (RBAM) that is required by CIP-002-3. The SRP examines whether an entity's RBAM is sufficient to properly identify the Critical Assets and Critical Cyber Assets that ensure the safe, reliable operation of the BPS. With FERC approval of Version 4, this program will also include added emphasis on

Version 4 bright-line criteria and Version 5 status updates. CID is scheduled to conduct 10 SRPs in 2013.

In the standards development area, the ERO continued the development of "Version 5" of the CIP Standards throughout the year. While the main focus of Version 5 development continues to address all the remaining FERC Order No. 706 directives, Version 5 contains several other changes based on practical experiences from both registered entities and ERO audit staffs.

**Support of Regional Entity Audit Oversight**

CID supports the efforts of NERC's Compliance Operations department and the Regional Entities to improve the consistency of compliance program results, improve risk-based approaches for auditing and spot checking, and promote a culture of security and compliance through education, transparency, and incentives.

In addition to the assigned CIP oversight audits of Regional Entities, the NERC CIP auditors are engaged with the following programs and initiatives:

- Managing the Technical Feasibility Exception (TFE) program, to include interface with the regional TFE managers and preparation of the annual report to FERC;
- Coordinating and planning CIP auditor workshops;
- Facilitating and providing administrative support to the CIP Compliance Working Group;
- Providing CIP subject matter expert presentations to regional compliance workshops;
- Providing CIP subject matter expertise and compliance liaison to the Cybersecurity 706 Standard Drafting Team;
- Providing CIP subject matter expertise to the Situational Awareness for FERC, NERC, and the Regions program;
- Providing subject matter expertise to NERC Event Analysis and Investigations;
- Providing CIP subject matter expertise in response to queries from industry and the public, as submitted via NERC's web site; and
- Participating as a liaison for CIP compliance issues/concerns during weekly NERC/FERC status conferences.

**ES-ISAC**

Authorities for all ISACs derive from Presidential Decision Directive 63 (PDD-63), which led to establishment of a framework to address critical infrastructure and key resource protection capabilities. ISACs represent a highly focused effort designed to meet these cross-sector information sharing requirements.

The ES-ISAC operates under the requirements and authority set forth in §1003 of the Rules of Procedure which states that NERC shall:

- coordinate electric industry activities to promote Critical Infrastructure Protection of the Bulk Power System in North America by taking a leadership role in Critical Infrastructure protection of the electricity sector so as to reduce vulnerability and improve mitigation and protection of the electricity sector's Critical Infrastructure
- serve as the electricity sector's sector coordinator and operate its Information Sharing and Analysis Center to gather information and communicate security-related threats and incidents within the sector, with United States and Canadian government agencies and with other Critical Infrastructure sectors.

The ES-ISAC gathers information from the disparate electric industry participants about security-related events, disturbances, and off-normal occurrences within the electricity sector and shares that information with other key governmental entities. In turn, these governmental entities provide the ES-ISAC with information regarding risks, threats, and warnings which the ES-ISAC is then responsible for disseminating throughout the Electricity Sub-sector. The two functions that the ES-ISAC supports, information sharing and analytics, are vitally important to all other critical infrastructures and key resource sectors that have active ISACs. Effective collaboration and communication is essential to addressing infrastructure protection and resilience within each sector, as well as the important interdependencies that exist among sectors.

The ES-ISAC capabilities accelerate the analysis and sharing of BPS reliability risk information within the energy sector. The ES-ISAC identifies industry events and occurrences that are appropriate topics for the issuance of Advisories, Recommendations and Essential Actions pursuant to the procedures in Section 810 of the ROP, which authorizes NERC to develop and distribute Alerts and Notifications. These Alerts and Notifications are divided into three different levels: Level 1, Advisories; Level 2, Recommendations; Level 3, Essential Actions. The Level 2 and Level 3 Alerts and Notifications bear a mandatory response requirement from the BPS entities. The ES-ISAC utilizes ROP 810 entity Alert response requirements to ensure that Alerts are confirmed received and the certain required responses are submitted for Level 2 and 3 Alerts.

In addition to Alerts and Notifications, NERC has the ability to request data or information from Registered Entities. Section 1600 of the ROP requires Registered Entities to respond to NERC data requests subject to NERC providing a copy of the proposed request to the Commission's Office of Electric Reliability, posting the proposed request for stakeholder comment, and obtaining Board of Trustees approval to issue the data request. Using this authority, the ES-ISAC may mandate Registered Entities' response to information requests that the ES-ISAC deems necessary to support its analytical functions or reduce BPS risk. Section 1600 also provides expedited procedures for requesting time-sensitive data or information.

The ES-ISAC also leverages its private portal to receive voluntary reports from industry members. This voluntary and open collaboration is the primary means the ES-ISAC uses to engage the industry on a daily basis. At its February 2012 meeting, key maturation steps for ES-

ISAC procedures were approved by the NERC Board of Trustees to enhance information sharing regarding risks potentially affecting BPS reliability. The board approved restrictions governing security information sharing among ES-ISAC personnel and NERC compliance and enforcement personnel in order to foster communications and information exchange between the ERO and industry regarding potential threats to BPS reliability.

Due to its formal role within the National Infrastructure Protection Plan, the ES-ISAC has a special relationship with DHS. The ES-ISAC maintains an integration capability on the operations floor of the National Cybersecurity and Communications Integration Center (NCCIC). This Top Secret, real-time, operations center is the hub for classified threat and vulnerability work, and the ES-ISAC plays a central role the NCCIC. This NCCIC floor is where the ES-ISAC cleared personnel analyze the threat and vulnerability components seen by the intelligence community and make an initial determination of potential impacts that the BPS may experience. The NCCIC also serves as a means to allow the ES-ISAC to provide subject matter expertise for matters of defense mission assurance, nuclear, oil, natural gas, water and other sector interdependency issues as they pertain to national and continental security interests. The ES-ISAC has also built other relationships with both the United States and Canadian governments. This includes Department of Energy (DoE), Canadian Secret Intelligence Service, and Department of Defense.

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## 2013 Resource Requirements

### Personnel

CID will have a total of four CIP auditors on staff at the end of 2012. To support projected increases in workload in connection with NERC audit oversight activities, transition to CIP Standards version 4, increased oversight activities, and additional ERO activities the CIP auditors support, CID proposes to add two additional CIP auditors in 2013. In addition, a Cyber Security Specialist will also be added to the ES-ISAC team to research, analyze, and disseminate information regarding significant cyber and physical security incidents, as well as conduct security-focused risk management and security incident reporting analysis. The Cyber Security Specialist will also support the ES-ISAC with event and incident data analysis, conducting analysis of all security-related incidents, and continue the development of incident descriptions, categories, and measurements. Finally, this individual will support access to operations center positions in the Industrial Control Systems Cyber Emergency Response Team and at the DHS National Incident Coordination Center in Washington, DC. This resource is required to stand

watch on the NCCIC floor on a rotating schedule. The 2.25 FTE increase in the chart at the beginning of this section is due to projected phasing and timing of hires.

**Contractors and Consultants**

The total projected 2013 CID contractor and consulting budget is $845k, an increase of $50k over the 2012 budget. The following is a description of the major areas of contractor and consulting support. A detailed breakdown of 2013 budgeted costs is set forth in Exhibit B, with a comparison to 2012.

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- GridEx 2013 Support-An exercise designed to validate the readiness of the Electricity Sub-sector to respond to a cyber security incident (CIP-008), strengthen utilities' crisis response functions, and provide input for internal cyber security program improvements. This bi-annual exercise focuses solely on disruptions and recovery from cyber security incidents (CIP-009) to the Electricity Sub-sector and includes subject matter experts from government and industry.
- 2013 ES-ISAC Members Conference-The ES-ISAC is planning a one-day conference in conjunction with NERC's 2013 Grid Security Conference. The purpose of this conference is to focus on the operational aspects of the ES-ISAC by sharing with entities the types of information the ES-ISAC receives from data feeds and other security partners, demonstrating tools the ES-ISAC and other security companies use to track and analyze data, and conducting security training on issues, vulnerabilities, and best practices. This item was reduced from $35k in the 1st draft to $30k in the present draft
- ES-ISAC – Secure Portal-The ES-ISAC portal build-out is underway in 2012 and includes a private, members-only portal to disseminate security information to members and to serve as collaboration "zones." Some of the planned zones include: a notification center (an exclusive zone for sharing of indicators of compromise); collaboration zones for groups such as Hydra (a technical subject matter expertise group) and the various NERC task forces; and an Alerts and Notification center to allow for non-registered entities to access the products. The members' portal component will be segregated from the compliance and enforcement programs of NERC and include a variety of information sharing mechanisms. The portal build-out will allow for bi-directional information sharing between the ES-ISAC and industry. Initial build out costs were incurred in 2012 and maintenance costs are required in 2013.
- ES-ISAC – Secure Connection for Bi-directional Information Sharing-Some emergent situations allow for quick transmission of secure information between the ES-ISAC and

DHS' United States Computer Emergency Readiness Team. This transmission occurs through formal and stringent technology requirements.

- Cyber Risk Preparedness Assessment (CRPA)-The CRPA is a project designed to assess the current cyber resiliency capabilities of BPS entities and the adequacy of existing reliability mechanisms related to the unique nature of cyber threats. Through these assessments, the ES-ISAC can target key areas for improvement and share areas of best practices with industry. The CRPA also provides the opportunity to educate participants and, through carefully defined deliverables, share effective practices and impart knowledge to all BPS entities. The cost to conduct a CRPA is based on contractor hourly fees, prepared materials, and travel expenses.
- Attack Tree Threat Modeling- Attack trees are hierarchical, graphical diagrams that show how low-level hostile activities interact and combine to achieve an adversary's objectives—usually with negative consequences for the attack victim. NERC contracted with a company that has developed an advanced attack tree-based threat risk assessment tool, which allows enterprises to discover which weaknesses are most likely to be used against them by attackers. This tool provides the results needed to justify security choices to company executives and security practitioners. The product is equally applicable to information technology and physical security. The 2013 expenses to maintain this software is $7,500 and is budgeted under Office Costs, which is where computer supplies and maintenance are reported. Draft #1 incorrectly included $50k for this item.
- Reporting Services-ES-ISAC staff must maintain a detailed understanding of emerging vulnerabilities and threats affecting industrial control systems and the bulk power system. This service gives ES-ISAC staff increased understanding of continuing trends, breaking news, and implications to the BPS. [The $40k that was reported under Contractor and Consultants in Draft #1 is now being reported as part of office costs since its subscription to a reporting service]
- Aurora webinars and reporting-NERC and the ES-ISAC have been working since 2007 to address the Aurora Vulnerability, a significant supply chain vulnerability that impacts digital protective control devices, which protect generators and motors in use throughout the bulk power system. The budget for this item was reduced from $60k in the 1st draft to $15k in the present draft
- Analytic capabilities- A software service that provides cyber awareness and continuous monitoring, and helps organizations protect against targeted attacks by gathering, correlating, and analyzing threat information from within their own networks, supply chains, and the rest of the Internet. This tool provides real-time internet communications visibility and analytics. The budget for this item was reduced from $65k in the 1st draft to $60k in the present draft
- Base Line Patterns and Analysis- a technique where abnormal conditions, such as malicious software from a compromised system communicating to command and control locations that are globally dispersed, are determined by comparing to patterns

established during normal conditions. This capability requires specialized tools and analysis to develop. [Note to reader- This is new in this draft and is being funded through a reduction reallocation of other proposed consulting budget amounts]

- Integration Support Services for the Wall of Knowledge- The Wall-of-Knowledge is a visual analytical tool that brings together different representations, or overlays, of data. The image of the North American BPS can be overlaid with the locations for known malicious software, other known events occurring on the grid such as outages, intelligence reporting, and activities from other sector ISACs. This combined multiple overlaid image allows the ES-ISAC analyst to determine subtle behaviors that may be correlated. The development of this capability requires that these data streams be "Integrated", which requires the assistance of specialized consultants. [Note to reader- This is new in this draft and is being funded through a reduction reallocation of other proposed consulting budget amounts]

**Statement of Activities, Fixed Assets Expenditures and Change in Working Capital**
**2012 Budget & Projection, and 2013 Budget**
**CRITICAL INFRASTRUCTURE DEPARTMENT**

| | 2012 Budget | 2012 Projection | Variance 2012 Projection v 2012 Budget Over(Under) | 2013 Budget | Variance 2013 Budget v 2012 Budget Over(Under) | 2013 Budget Draft 1 | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|---|---|
| **Funding** | | | | | | | |
| **ERO Funding** | | | | | | | |
| NERC Assessments | $ 7,396,148 | $ 7,396,148 | $ - | $ 7,941,178 | $ 545,029 | $ 8,014,878 | $ (73,700) |
| Penalty Sanctions | - | - | - | 345,283 | 345,283 | 345,283 | - |
| **Total NERC Funding** | **$ 7,396,148** | **$ 7,396,148** | **$ -** | **$ 8,286,461** | **$ 890,313** | **$ 8,360,161** | **$ (73,700)** |
| Membership Dues | - | - | - | - | - | - | - |
| Testing Fees | - | - | - | - | - | - | - |
| Services & Software | - | - | - | - | - | - | - |
| Workshops | - | - | - | 95,000 | 95,000 | - | 95,000 |
| Interest | - | - | - | 2,862 | 2,862 | 2,862 | - |
| Miscellaneous | - | - | - | - | - | - | - |
| **Total Funding (A)** | **$ 7,396,148** | **$ 7,396,148** | **$ -** | **$ 8,384,323** | **$ 988,175** | **$ 8,363,024** | **$ 21,300** |
| **Expenses** | | | | | | | |
| **Personnel Expenses** | | | | | | | |
| **Salaries** | $ 2,946,168 | $ 2,508,848 | $ (437,320) | $ 2,885,564 | $ (60,604) | $ 2,929,993 | (44,429) |
| **Payroll Taxes** | 169,764 | 153,301 | (16,463) | 177,145 | 7,381 | 177,808 | (663) |
| **Benefits** | 280,269 | 196,658 | (83,611) | 258,631 | (21,638) | 258,638 | (7) |
| **Retirement Costs** | 409,489 | 264,606 | (144,883) | 321,117 | (88,372) | 322,306 | (1,189) |
| **Total Personnel Expenses** | **$ 3,805,690** | **$ 3,123,413** | **$ (682,277)** | **$ 3,642,457** | **$ (163,233)** | **$ 3,688,745** | **(46,288)** |
| **Meeting Expenses** | | | | | | | |
| **Meetings** | $ 104,570 | $ 48,000 | $ (56,570) | $ 145,000 | $ 40,430 | $ 104,570 | 40,430 |
| **Travel** | 440,000 | 440,000 | - | 420,000 | (20,000) | 440,000 | (20,000) |
| **Conference Calls** | 24,000 | 24,000 | - | 24,000 | - | 24,000 | - |
| **Total Meeting Expenses** | **$ 568,570** | **$ 512,000** | **$ (56,570)** | **$ 589,000** | **$ 20,430** | **$ 568,570** | **20,430** |
| **Operating Expenses** | | | | | | | |
| **Consultants & Contracts** | $ 795,000 | $ 537,620 | $ (257,380) | $ 785,000 | $ (10,000) | $ 845,000 | (60,000) |
| **Office Rent** | - | - | - | - | - | - | - |
| **Office Costs** | 45,000 | 93,750 | 48,750 | 125,250 | 80,250 | - | 125,250 |
| **Professional Services** | - | 468 | 468 | 500 | 500 | - | 500 |
| **Miscellaneous** | - | 282 | 282 | 1,000 | 1,000 | - | 1,000 |
| **Depreciation** | - | - | - | - | - | - | - |
| **Total Operating Expenses** | **$ 840,000** | **$ 632,120** | **$ (207,880)** | **$ 911,750** | **$ 71,750** | **$ 845,000** | **$ 66,750** |
| **Total Direct Expenses** | **$ 5,214,260** | **$ 4,267,533** | **$ (946,727)** | **$ 5,143,207** | **$ (71,053)** | **$ 5,102,315** | **$ 40,892** |
| **Indirect Expenses** | **$ 2,274,398** | **$ 2,921,522** | **$ 647,123** | **$ 3,198,498** | **$ 924,100** | **$ 3,178,217** | **$ 20,281** |
| **Other Non-Operating Expenses** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **-** |
| **Total Expenses (B)** | **$ 7,488,658** | **$ 7,189,055** | **$ (299,604)** | **$ 8,341,705** | **$ 853,047** | **$ 8,280,532** | **$ 61,173** |
| **Change in Assets** | **$ (92,510)** | **$ 207,094** | **$ 299,604** | **$ 42,618** | **$ 135,128** | **$ 82,492** | **(39,873)** |
| **Fixed Assets** | | | | | | | |
| Depreciation | - | - | - | - | - | - | - |
| Computer & Software CapEx | - | 37,500 | 37,500 | - | - | - | - |
| Furniture & Fixtures CapEx | - | - | - | - | - | - | - |
| Equipment CapEx | - | - | - | - | - | - | - |
| Leasehold Improvements | - | - | - | - | - | - | - |
| Allocation of Fixed Assets | $ (92,510) | $ (60,356) | 32,154 | 42,618 | 135,128 | $ 82,492 | (39,873) |
| **Inc(Dec) in Fixed Assets ( C )** | **$ (92,510)** | **$ (22,856)** | **$ 69,654** | **$ 42,618** | **$ 135,128** | **$ 82,492** | **$ -** |
| **TOTAL BUDGET (=B + C)** | **$ 7,396,148** | **$ 7,166,198** | **$ (229,950)** | **$ 8,384,323** | **$ 988,175** | **$ 8,363,024** | |
| **TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)** | **$ (0)** | **$ 229,950** | **$ 229,950** | **$ -** | **$ 0** | **$ -** | **$ -** |
| **FTEs** | **17.00** | **16.29** | **(0.71)** | **19.25** | **2.25** | **19.25** | **-** |

## Summary of Variances by Category – 2013 Budget Compared to the 2012 Budget

- Personnel Expenses – The decrease in salaries and payroll taxes is due to lower average salaries per FTE in the department. Lower average costs per FTE for Benefits and Retirement due to changes to NERC's employee benefit and retirement plans resulted in lower projected costs in 2013.
- Meetings expense includes the cost of the Grid Security Conference, which is offset by $95k in projected funding from Workshop fees, and quarterly Critical Infrastructure Protection Committee meetings.

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- Office Costs – Primarily related to increases in cell phone and air card charges due to having more FTEs on staff and related to annual maintenance costs for software used to support activities of the ES-ISAC.

# Training, Education, and Operator Certification

| Training, Education and Operator Certification (in whole dollars) | 2012 Budget | 2013 Budget | Increase (Decrease) | 2013 Budget -Prior Draft | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|
| Total FTEs | 6.75 | 8.00 | 1.25 | 8 | - |
| Direct Expenses | $ 2,055,655 | $ 2,222,728 | $ 167,073 | $ 2,311,189 | $ (88,461) |
| Indirect Expenses | $ 1,086,675 | $ 1,329,246 | $ 242,571 | $ 1,320,818 | $ 8,428 |
| Other Non-Operating Expenses | $ - | $ - | $ - | | $ - |
| Inc(Dec) in Fixed Assets | $ (44,201) | $ 17,711 | $ 61,912 | $ 34,282 | $ (16,571) |
| Total Funding Requirement | $ 3,098,130 | $ 3,569,685 | $ 471,556 | $ 3,666,289 | $ (96,604) |

### Background and Scope

NERC's Training and Education Program provides oversight and coordination of the delivery of training programs that support the ERO's mission. NERC's Training and Education Program also supports NERC's System Operator Certification and Continuing Education (SOCCED) programs, which ensure that personnel operating the bulk power system have the skills, training, and qualifications needed to operate the system reliably. NERC maintains the credentials required to work in system control centers across North America for over 6,000 system operators. NERC's system operator certification exam is designed to test specific knowledge of job skills and reliability standards. It also prepares operators to comply with requirements of reliability standards and appropriately operate the BPS during normal and emergency operations. Certification exams are created by the Personnel Certification Governance Committee, an industry group of operations experts, trainers, and supervisors. Under the PCGC oversight, the Examination Working Group periodically updates and publishes new exams. Once an operator passes the certification exam, certification is maintained by completing NERC-approved continuing education courses and activities. The Personnel Subcommittee, composed of industry training experts, provides oversight of the Continuing Education program.

### 2013 Goals and Deliverables

In response to stakeholder and Regional Entity feedback, training and education opportunities will be further expanded and focused for NERC and Regional Entity staff, registered entities, and stakeholders. For registered entities, this training and education will focus on objectives related to various reliability standards including how to best comply with standards and improve bulk power system reliability, as well as cyber related topics. For NERC and ~~r~~Regional Entity staff, the training and education will focus on consistent audit and investigation techniques and standards compliance reviews, including the Compliance Enforcement Initiative/FFT processing and other improvements in compliance and enforcement practices. NERC will continue to offer training in auditor skills to promote continued development of auditing expertise. NERC will leverage information technology systems to better deliver and share common training products and information with regional and registered entities. Other training will focus on knowledge and skills development in a number of key areas, including:

- Critical Infrastructure Protection standards information;

- Development and implementation of clear and technically sound reliability standards;
- Key lessons learned and trends from events;
- Identified themes from trending and common cause analyses;
- Risk-based assessment methods;
- Effective compliance cultures with practices, procedures and controls to address reliability risks;
- Effective root, apparent and common cause analysis methods;
- Quality improvement of registered entity self-reporting and self-certification;
- Currently-monitored standards;
- Reliability assessment/system planning fundamentals and requirements;
- Entity registration process, issues, and alternatives;
- Human performance error reduction techniques; and
- Systematic approach to training

NERC will continue to provide learning opportunities through workshops hosted by the Regional Entities. NERC will also host workshops, webinars, and training courses, as well as use vendors to develop training modules and supplement internal training resources, as NERC designs and implements further NERC-hosted electronic training and educational opportunities. NERC's Training and Education group will also continue to advance and improve the skills of NERC's operating staff. NERC's Human Resources department will continue to budget and manage the delivery of more traditional corporate employee training and continuing education programs.

## Resource Requirements

### Personnel

One (1) position will be added to provide administrative support, the cost of which will be funded through operator certification and testing fees. The 1.25 FTEs in the chart above is the result of reflecting the full year effect of a phasing in of 2012 personnel additions.

### Contractor Expenses

The total proposed consulting and contractor expenses of approximately $850~~900~~k in 2013 represents an increase of approximately $253~~300~~k over 2012 levels. This increase is primarily the result of a multi-year project to continue improvements to the SOCCED database as recommended in the three year assessment. The project will provide improved and efficient interface and ease of use for system operators & supervisors, trainers, training providers, and staff, including automating many features currently done manually and/or individually.

Further detail in support of the proposed 2013 contractor and consulting budget to support Training, Education and Operator Certification is set forth in Exhibit B, including a comparison to 2012 budgeted amounts. The primary areas of contractor and consulting support include:

- Testing services to develop, administer, proctor, score, and support system operator certification exams across North America.
- Ongoing hosting and maintenance fees for the SOCCED database.
- Improvements to the SOCCED database described above.
- Supplemental support to Continuing Education Review Panel industry volunteers to review and audit over 2,500 individual learning activities and provider applications received each year.[34]
- Audit team leader soft skills training delivered by certified NERC staff and/or consultants to support effective dialogue and communications between audit teams and registered entities will be provided quarterly using vendor licensed materials.
- Vendor supported BPS technical training ~~will also be provided~~ for select NERC staff, including auditors, technical and support staff.
- Auditor training by recognized auditing specialists for NERC and Regional Entity staff to promote continued development of compliance staff.
- Web based training development for ERO staff and/or industry, including standards applications, risk assessment training, industry human performance fundamentals, and BPS events lessons learned.

**Use of Working Capital Funds for ~~of~~ System Operator Certification and Continuing Education Database Upgrades**

As part of the proposed working capital guidelines which will be presented to the NERC Finance and Audit Committee at its May 8, 2012 meeting, management is recommending that in the event ~~the company~~NERC realizes higher levels of funding from operator certification testing and renewal fees above incurred expenses, this excess funding will be ~~added to working capital and~~ set aside as an operating reserve and used solely for operator training and certification needs as determined by ~~the company~~management and the Personnel Certification Governance Committee. This is consistent with the requirements of Section 602.4.10 of the Rules of Procedure. Expenditures of these funds would be reported as part of ~~the company~~NERC's quarterly variance reporting to the finance and audit committee, which reports are also posted on ~~the company's~~NERC's website and reviewed on conference calls or meetings of the committee which are open to the public. The projected $250K in 2013 costs for improvements to the System Operator Certification and Continuing Education Database are proposed to be funded through use of excess working capital reserve additions ~~in 2012 due to~~resulting higher than anticipated ~~2011 and 2012 funding~~revenues from system operator certification and continuing educations program fees compared to program costs~~s~~. This is part of a multiyear project that is estimated to cost approximately $600k.

As further described in Exhibit C, NERC is projecting a $1.750 operating reserve balance for the System Operator Certification and Continuing Education Program. Given the size of this

[34] Review and approval of learning activity applications results in over 400,000 hours of continuing education per year for the industry's certified system operators.

projected balance, the Personnel Certification Governance Committee is reviewing its current fee structure. NERC's final budget will reflect any known changes to this fee structure.

**Statement of Activities, Fixed Assets Expenditures and Change in Working Capital**
**2012 Budget & Projection, and 2013 Budget**
**TRAINING, EDUCATION and OPERATOR CERTIFICATION**

| | 2012 Budget | 2012 Projection | Variance 2012 Projection v 2012 Budget Over(Under) | 2013 Budget | Variance 2013 Budget v 2012 Budget Over(Under) | 2013 Budget Draft 1 | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|---|---|
| **Funding** | | | | | | | |
| **ERO Funding** | | | | | | | |
| NERC Assessments | $ 916,083 | $ 916,083 | $ 1 | $ 1,297,501 | $ 381,419 | $ 1,090,605 | $ 206,896 |
| Penalty Sanctions | - | - | | 143,494 | 143,494 | 143,494 | 0 |
| **Total NERC Funding** | **$ 916,083** | **$ 916,083** | **$ 1** | **$ 1,440,996** | **$ 524,913** | **$ 1,234,099** | **$ 206,897** |
| Membership Dues | - | - | - | - | - | | - |
| Testing Fees | 2,061,000 | 2,061,000 | - | 1,877,500 | (183,500) | 2,061,000 | (183,500) |
| Services & Software | - | - | - | - | - | - | - |
| Workshops | 120,000 | - | (120,000) | - | (120,000) | 120,000 | (120,000) |
| Interest | 1,047 | 1,097 | 51 | 1,190 | 143 | 1,190 | (0) |
| Miscellaneous | | - | - | - | - | - | - |
| **Total Funding (A)** | **$ 3,098,129** | **$ 2,978,180** | **$ (119,949)** | **$ 3,319,685** | **$ 221,556** | **$ 3,416,289** | **$ (96,604)** |
| **Expenses** | | | | | | | |
| **Personnel Expenses** | | | | | | | |
| **Salaries** | $ 879,333 | $ 809,868 | $ (69,465) | $ 849,090 | $ (30,243) | $ 860,850 | (11,760) |
| **Payroll Taxes** | 57,024 | 51,698 | (5,326) | 57,197 | 173 | 55,565 | 1,632 |
| **Benefits** | 108,672 | 80,836 | (27,836) | 128,640 | 19,968 | 103,100 | 25,540 |
| **Retirement Costs** | 119,778 | 81,548 | (38,230) | 96,931 | (22,847) | 96,931 | 0 |
| **Total Personnel Expenses** | **$ 1,164,807** | **$ 1,023,950** | **$ (140,857)** | **$ 1,131,859** | **$ (32,948)** | **$ 1,116,446** | **15,413** |
| **Meeting Expenses** | | | | | | | |
| **Meetings** | $ 124,450 | $ 36,000 | $ (88,450) | $ 15,000 | $ (109,450) | $ 124,450 | (109,450) |
| **Travel** | 48,000 | 48,000 | - | 70,000 | 22,000 | 48,000 | 22,000 |
| **Conference Calls** | 58,100 | 58,100 | - | 58,100 | - | 58,100 | - |
| **Total Meeting Expenses** | **$ 230,550** | **$ 142,100** | **$ (88,450)** | **$ 143,100** | **$ (87,450)** | **$ 230,550** | **(87,450)** |
| **Operating Expenses** | | | | | | | |
| **Consultants & Contracts** | $ 596,448 | $ 830,258 | $ 233,810 | $ 849,834 | $ 253,386 | $ 900,343 | (50,509) |
| **Office Rent** | - | - | - | - | - | - | - |
| **Office Costs** | 63,600 | 96,000 | 32,400 | 96,500 | 32,900 | 63,600 | 32,900 |
| **Professional Services** | - | 186 | 186 | 435 | 435 | - | 435 |
| **Miscellaneous** | 250 | 250 | - | 1,000 | 750 | 250 | 750 |
| **Depreciation** | - | - | - | - | - | | - |
| **Total Operating Expenses** | **$ 660,298** | **$ 926,694** | **$ 266,396** | **$ 947,769** | **$ 287,471** | **$ 964,193** | **$ (16,424)** |
| **Total Direct Expenses** | **$ 2,055,655** | **$ 2,092,744** | **$ 37,089** | **$ 2,222,728** | **$ 167,073** | **$ 2,311,189** | **$ (88,461)** |
| **Indirect Expenses** | **$ 1,086,675** | **$ 1,205,195** | **$ 118,520** | **$ 1,329,246** | **$ 242,571** | **$ 1,320,818** | **$ 8,428** |
| **Other Non-Operating Expenses** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | **$ -** |
| **Total Expenses (B)** | **$ 3,142,330** | **$ 3,297,939** | **$ 155,609** | **$ 3,551,974** | **$ 409,644** | **$ 3,632,007** | **$ (80,033)** |
| **Change in Assets** | **$ (44,201)** | **$ (319,759)** | **$ (275,558)** | **$ (232,289)** | **$ (188,088)** | **$ (215,718)** | **(16,571)** |
| **Fixed Assets** | | | | | | | |
| Depreciation | - | - | - | - | - | | - |
| Computer & Software CapEx | - | - | - | - | - | | - |
| Furniture & Fixtures CapEx | | - | - | - | - | | - |
| Equipment CapEx | | - | - | - | - | | - |
| Leasehold Improvements | | - | - | - | - | | - |
| Allocation of Fixed Assets | $ (44,201) | $ (24,898) | 19,303 | 17,711 | $ 61,912 | $ 34,182 | (16,471) |
| **Inc(Dec) in Fixed Assets ( C )** | **$ (44,201)** | **$ (24,898)** | **$ 19,303** | **$ 17,711** | **$ 61,912** | **$ 34,282** | **$ -** |
| **TOTAL BUDGET (=B + C)** | **$ 3,098,129** | **$ 3,273,041** | **$ 174,912** | **$ 3,569,685** | **$ 471,556** | **$ 3,666,289** | |
| **TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)** | **$ -** | **$ (294,861)** | **$ (294,861)** | **$ (250,000)** | **$ (250,000)** | **$ (250,000)** | **$ -** |
| **FTEs** | **6.75** | **6.72** | **(0.03)** | **8.00** | **1.25** | **8.00** | **-** |

## Summary of Variances by Category – 2013 Budget Compared to the 2012 Budget

- Meetings Expense – In 2012, all NERC sponsored workshops and the projected funding from workshop fees were budgeted in the Training Department. In 2013, the projected funding from workshop fees and workshop expenses are recorded in the Program sponsoring the workshop.
- Consultants & Contracts – The increase is for the upgrade of the SOCCED database as described above

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# Administrative Services

| Administrative Services (in whole dollars) | 2012 Budget | 2013 Budget | Increase (Decrease) | 2013 Budget -Prior Draft | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|
| Total FTEs | 47.75 | 51.75 | 4.00 | 51.75 | - |
| Total Direct Expenses | $ 20,767,559 | $ 22,347,949 | $ 1,580,390 | $ 22,206,246 | $ 141,703 |
| Inc(Dec) in Fixed Assets | $ (844,731) | $ 297,774 | $ 1,142,505 | $ 576,369 | $ (278,595) |
| Less: Other Funding Sources | | | $ - | | $ - |
| Total Allocation to Statutory Programs as Indirect Expenses | $ 19,922,828 | $ 22,645,723 | $ 2,722,895 | $ 22,782,616 | $ (136,893) |
| Funding Requirement for Working Capital | $ (0) | $ - | $ 0 | | $ - |

## Program Scope and Functional Description

NERC's Administrative Services area includes the budget for all business and administrative functions of the organization, including (1) technical committees and member forums, (2) General and Administrative, which includes Board of Trustees fees and expenses, the president and chief executive officer and support staff, communications and governmental affairs, and office rent (3) Legal and Regulatory, (4) Human Resources, (5) Information Technology, (6) Finance and Accounting, and general administrative expenses necessary to support program area activities. The resource requirements and comparative budget information for each of these functions is described further below. Costs incurred for these services are allocated as an indirect expense across NERC's other program areas.

### Technical Committees and Members' Forum Program

While NERC management and staff will continue to interact with and support numerous reliability related forums, including but not limited to the North American Transmission Forum and Generator Forum, NERC's 2013 budget does not contain specific funding for any additional forum activities.

### General and Administrative

| General and Administrative (in whole dollars) | 2012 Budget | 2013 Budget | Increase (Decrease) | 2013 Budget - Prior Draft | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|
| Total FTEs | 7.00 | 7.00 | - | 7.00 | - |
| Total Direct Expenses | $ 6,800,249 | $ 6,750,589 | $ (49,660) | 6,568,579 | 182,010 |
| Inc(Dec) in Fixed Assets | $ (255,775) | $ (350,526) | $ (94,751) | (255,775) | (94,751) |
| Working Capital Requirement | $ - | $ - | $ - | | - |

## Background and Scope

The General and Administrative area is responsible for the administration and general management of the organization. Expenses allocated in this area include office rent, personnel

and related costs of the CEO, a senior advisor to the CEO, the CEO's executive assistant, communications and public relations staff, and costs related to the Board of Trustees.

**Statement of Activities, Fixed Assets Expenditures and Change in Working Capital**
**2012 Budget & Projection, and 2013 Budget**
**GENERAL and ADMINISTRATIVE**

| | 2012 Budget | 2012 Projection | Variance 2012 Projection v 2012 Budget Over(Under) | 2013 Budget | Variance 2013 Budget v 2012 Budget Over(Under) | 2013 Budget Draft 1 | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|---|---|
| **Funding** | | | | | | | |
| **ERO Funding** | | | | | | | |
| NERC Assessments | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Penalty Sanctions | - | - | - | - | - | - | - |
| **Total NERC Funding** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Membership Dues | - | - | - | - | - | - | - |
| Testing Fees | - | - | - | - | - | - | - |
| Services & Software | - | - | - | - | - | - | - |
| Workshops | - | - | - | - | - | - | - |
| Interest | - | - | - | - | - | - | - |
| Miscellaneous | - | - | - | - | - | - | - |
| **Total Funding (A)** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Expenses** | | | | | | | |
| **Personnel Expenses** | | | | | | | |
| **Salaries** | $ 1,561,193 | $ 1,701,240 | $ 140,048 | $ 1,316,844 | $ (244,349) | $ 1,185,040 | 131,804 |
| **Payroll Taxes** | 67,331 | 70,667 | 3,336 | 58,909 | (8,422) | 59,173 | (264) |
| **Benefits** | 208,278 | 176,116 | (32,162) | 170,748 | (37,530) | 170,748 | - |
| **Retirement Costs** | 236,295 | 68,341 | (167,954) | 25,722 | (210,573) | 175,722 | (150,000) |
| **Total Personnel Expenses** | $ 2,073,097 | $ 2,016,364 | $ (56,733) | $ 1,572,223 | $ (500,873) | $ 1,590,683 | (18,460) |
| **Meeting Expenses** | | | | | | | |
| **Meetings** | $ 224,000 | $ 224,600 | $ 600 | $ 260,000 | $ 36,000 | $ 259,000 | 1,000 |
| **Travel** | 265,120 | 285,120 | 20,000 | 322,000 | 56,880 | 265,120 | 56,880 |
| **Conference Calls** | 57,500 | 57,500 | - | 57,500 | - | 57,500 | - |
| **Total Meeting Expenses** | $ 546,620 | $ 567,220 | $ 20,600 | $ 639,500 | $ 92,880 | $ 581,620 | 57,880 |
| **Operating Expenses** | | | | | | | |
| **Consultants & Contracts** | $ - | $ - | $ - | $ - | $ - | $ - | - |
| **Office Rent** | 2,304,257 | 2,784,036 | 479,779 | 2,516,814 | 212,557 | 2,520,000 | (3,186) |
| **Office Costs** | 480,500 | 341,662 | (138,838) | 507,000 | 26,500 | 480,500 | 26,500 |
| **Professional Services** | 1,130,000 | 1,265,096 | 135,096 | 1,159,525 | 29,525 | 1,130,000 | 29,525 |
| **Miscellaneous** | 10,000 | 10,050 | 50 | 5,000 | (5,000) | 10,000 | (5,000) |
| **Depreciation** | 255,775 | 378,421 | 122,646 | 350,526 | 94,751 | 255,775 | 94,751 |
| **Total Operating Expenses** | $ 4,180,532 | $ 4,779,265 | $ 598,733 | $ 4,538,865 | $ 358,333 | $ 4,396,275 | $ 142,590 |
| **Total Direct Expenses** | $ 6,800,249 | $ 7,362,849 | $ 562,600 | $ 6,750,589 | $ (49,660) | $ 6,568,579 | $ 182,010 |
| **Indirect Expenses** | $ (6,800,249) | $ (7,423,804) | $ (623,555) | $ (6,750,589) | $ 49,660 | $ (6,568,579) | $ (182,010) |
| **Other Non-Operating Expenses** | $ - | $ 60,955 | $ 60,955 | $ - | $ - | $ - | - |
| **Total Expenses (B)** | $ - | $ - | $ (0) | $ - | $ (0) | $ - | $ (0) |
| **Change in Assets** | $ - | $ - | $ 0 | $ - | $ 0 | $ - | - |
| **Fixed Assets** | | | | | | | |
| Depreciation | (255,775) | (378,421) | (122,646) | (350,526) | (94,751) | (255,775) | (94,751) |
| Computer & Software CapEx | | - | - | - | - | - | - |
| Furniture & Fixtures CapEx | - | 212 | 212 | - | - | - | - |
| Equipment CapEx | | - | - | - | - | - | - |
| Leasehold Improvements | | 47,841 | 47,841 | - | - | - | - |
| Allocation of Fixed Assets | $ 255,775 | $ 330,368 | 74,593 | 350,526 | 94,751 | $ 255,775 | 94,751 |
| **Inc(Dec) in Fixed Assets ( C )** | $ - | $ - | $ - | $ - | $ - | $ - | $ 94,751 |
| **TOTAL BUDGET (=B + C)** | $ - | $ - | $ (0) | $ - | $ (0) | $ - | |
| **TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)** | $ - | $ - | $ 0 | $ - | $ 0 | $ - | $ - |
| **FTEs** | 7.00 | 8.00 | 1.00 | 7.00 | - | 7.00 | - |

## Summary of Variances by Category – 2013 Budget Compared to the 2012 Budget

- Personnel Expense – The average cost of all personnel expense categories is lower in 2013 as previously explained.
- Meetings – Includes the cost of quarterly Board of Trustee and Members' Representative Committee meetings, ERO executive staff meetings, and employee meetings.

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- Rent – As previously described, the increased is due to an increase in rented space in ~~new~~NERC's offices in Atlanta and Washington, DC.

## Legal, Regulatory and Government Relations

| Legal and Regulatory (in whole dollars) | 2012 Budget | 2013 Budget | Increase (Decrease) | 2013 Budget - Prior Draft | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|
| Total FTEs | 13.00 | 14.00 | 1.00 | 14.00 | - |
| Total Direct Expenses | $ 4,021,294 | $ 4,134,374 | $ 113,080 | 4,026,677 | 107,697 |
| Inc(Dec) in Fixed Assets | $ - | $ - | $ - | - | - |
| Working Capital Requirement | $ - | $ - | $ - | - | - |

### Background and Scope

The Legal and Regulatory department provides legal and regulatory support to the organization. Expenses allocated to this department include: General Counsel, attorneys, and consulting costs to support Canadian governmental affairs. This department's workload is largely derivative of and supports the work of several of the NERC's key program areas. Increasing demands are being placed on this group from three primary areas: compliance operations, investigations, and standards. In the compliance operations area, there are increased requests for legal support for significant audits. In the investigations area, there are increasing calls for legal support for investigation teams. In standards, there are increasing calls for legal participation with drafting teams, drafting assistance and quality review of standards projects. In addition, recent FERC orders indicate a need for increased resources devoted to the development of filings for approval of standards.

In addition, this department is also responsible for providing a wide range of legal support to the NERC management team regarding antitrust, corporate, commercial, insurance, contract, employment, real estate, copyright, tax, legislation and other legal matters, the needs for which are growing as the NERC and the ERO mature and legal support needs become broader and more complex.

### Resource Requirements

One FTE was transferred to Legal and Regulatory in 2012 to provide administrative support for the Washington, D.C. office. No additional staff is proposed to be added to the legal and regulatory areas in 2013.

Outside law firms and consultants supporting this area are budgeted and tracked as Professional Services. The 2013 Professional Services budget is $900K for 2013 which is $ 150K more than the 2012 budget and is to support the next ERO Performance Assessment.

**Statement of Activities, Fixed Assets Expenditures and Change in Working Capital**
**2012 Budget & Projection, and 2013 Budget**
**LEGAL and REGULATORY**

| | 2012 Budget | 2012 Projection | Variance 2012 Projection v 2012 Budget Over(Under) | 2013 Budget | Variance 2013 Budget v 2012 Budget Over(Under) | 2013 Budget Draft 1 | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|---|---|
| **Funding** | | | | | | | |
| **ERO Funding** | | | | | | | |
| NERC Assessments | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Penalty Sanctions | | $ - | | - | | - | - |
| **Total NERC Funding** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Membership Dues | - | - | - | - | - | - | - |
| Testing Fees | - | - | - | - | - | - | - |
| Services & Software | - | - | - | - | - | - | - |
| Workshops | - | - | - | - | - | - | - |
| Interest | - | - | - | - | - | - | - |
| Miscellaneous | - | - | - | - | - | - | - |
| **Total Funding (A)** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Expenses** | | | | | | | |
| **Personnel Expenses** | | | | | | | |
| **Salaries** | $ 2,317,740 | $ 2,261,591 | $ (56,149) | $ 2,282,090 | $ (35,650) | $ 2,299,165 | (17,075) |
| **Payroll Taxes** | 118,966 | 122,908 | 3,942 | 117,899 | (1,067) | 118,126 | (227) |
| **Benefits** | 249,428 | 164,512 | (84,916) | 168,092 | (81,336) | 181,257 | (13,165) |
| **Retirement Costs** | 327,545 | 254,512 | (73,033) | 261,733 | (65,812) | 262,263 | (530) |
| **Total Personnel Expenses** | $ 3,013,679 | $ 2,803,523 | $ (210,156) | $ 2,829,814 | $ (183,865) | $ 2,860,811 | (30,997) |
| **Meeting Expenses** | | | | | | | |
| **Meetings** | $ 5,000 | $ 5,000 | $ - | $ 5,000 | $ - | $ 5,000 | - |
| **Travel** | 74,000 | 120,000 | 46,000 | 144,500 | 70,500 | 74,000 | 70,500 |
| **Conference Calls** | 3,200 | 3,200 | - | 3,200 | - | 3,200 | - |
| **Total Meeting Expenses** | $ 82,200 | $ 128,200 | $ 46,000 | $ 152,700 | $ 70,500 | $ 82,200 | 70,500 |
| **Operating Expenses** | | | | | | | |
| **Consultants & Contracts** | $ 141,750 | $ 141,750 | $ - | $ 150,000 | $ 8,250 | $ 150,000 | - |
| **Office Rent** | - | - | - | - | - | - | - |
| **Office Costs** | 32,915 | 60,000 | 27,085 | 50,500 | 17,585 | 32,915 | 17,585 |
| **Professional Services** | 750,000 | 1,350,000 | 600,000 | 950,360 | 200,360 | 900,000 | 50,360 |
| **Miscellaneous** | 750 | 750 | - | 1,000 | 250 | 750 | 250 |
| **Depreciation** | - | - | - | - | - | - | - |
| **Total Operating Expenses** | $ 925,415 | $ 1,552,500 | $ 627,085 | $ 1,151,860 | $ 226,445 | $ 1,083,665 | $ 68,195 |
| **Total Direct Expenses** | $ 4,021,294 | $ 4,484,223 | $ 462,929 | $ 4,134,374 | $ 113,080 | $ 4,026,677 | $ 107,697 |
| **Indirect Expenses** | $ (4,021,294) | $ (4,484,223) | $ (462,929) | $ (4,134,374) | $ (113,080) | $ (4,026,677) | $ (107,697) |
| **Other Non-Operating Expenses** | $ - | $ - | $ - | $ - | $ - | $ - | - |
| **Total Expenses (B)** | $ - | $ - | $ - | $ - | $ - | $ - | $ 0 |
| **Change in Assets** | $ - | $ - | $ - | $ - | $ - | $ - | - |
| **Fixed Assets** | | | | | | | |
| Depreciation | - | - | - | - | - | - | - |
| Computer & Software CapEx | | - | | - | - | - | - |
| Furniture & Fixtures CapEx | | - | | - | - | - | - |
| Equipment CapEx | | - | | - | - | - | - |
| Leasehold Improvements | | - | | - | - | - | - |
| Allocation of Fixed Assets | | $ - | | - | | $ - | - |
| **Inc(Dec) in Fixed Assets ( C )** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **TOTAL BUDGET (=B + C)** | $ - | $ - | $ - | $ - | $ - | $ - | |
| **TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **FTEs** | 13.00 | 13.65 | | 14.00 | 1.00 | 14.00 | - |

## Summary of Variances by Category – 2013 Budget Compared to the 2012 Budget

- Personnel Expense – As previously described, the decrease is due to lower average costs per FTE and changes to NERC's employee benefits and retirement plans.
- Travel – Legal staff travel will increase due to increased participation in standards drafting team meetings and ERO Legal working group meetings.

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## Information Technology

| Information Technology (in whole dollars) | 2012 Budget | 2013 Budget | Increase (Decrease) | 2013 Budget - Prior Draft | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|
| Total FTEs | 12.75 | 16.75 | 4.00 | 16.75 | - |
| Total Direct Expenses | $ 6,629,579 | $ 8,049,937 | $ 1,420,358 | 8,314,967 | (265,030) |
| Inc(Dec) in Fixed Assets | $ (588,185) | $ 649,098 | $ 1,237,283 | 832,915 | (183,817) |
| Working Capital Requirement | $ (0) | $ - | $ 0 | | - |

### Background and Scope

NERC's Information Technology Department is responsible for planning, designing, implementing and operating technology in support of the ERO's goals and objectives. An important IT initiative in 2013 involves the implementation of a centralized data repository with the necessary infrastructure to accept inbound data and catalog this data in one location for access across the ERO. The data repository will provide the necessary visibility to information required by NERC and the Regional Entities in order to gain better data intelligence and collaboration and effectively and efficiently perform key functions.

The ERO has many methods by which to obtain data required to ensure the reliability of the bulk electric system. However there presently is no one single location in which to capture and mine data across the ERO to give broad spectrum visibility across multiple disciplines: standards, compliance operations, enforcement, critical infrastructure protection, events analysis, reliability risk assessment and management. Implementation of a single data repository designed to capture information across disciplines within the ERO sets the stage for improved reporting, data consistency, improved efficiency and adherence to regulatory requirements. The next phase of implementation will leverage tools such as Microsoft SharePoint 2010 in addition to other business intelligence tools to create applications for both NERC and the Regions for a single, holistic look at data across the ERO. The resulting single repository of data will be more efficient across NERC and the Regions, coupled with lower resource utilization required in support of the current multi-database, multi-application infrastructure.

NERC's 2013 IT budget sets the framework to commence implementation of a single data repository. The proposed contract, consulting, operations and maintenance budget amounts are tailored to ensure the building blocks are in place to support this and other strategic ERO initiatives and applications started in 2012.

### 2013 Goals and Deliverables

- (Multi-year effort) With the Regional Entities and external consulting support, deploy a common, enterprise-wide technology platform that embraces the requirements of Regional Entities and stakeholders for reliable, secure, efficient, and cost-effective systems and services.

- (Multi-year effort) design a data warehouse capability - single repository of data designed to provide a reliable, stable, secure environment for reporting across multiple disciplines ex., RAPA, Compliance, Standards, Enforcement, etc.
- Implement disaster recovery of critical IT resources (e~~x~~g., Exchange (email), NERC forward facing web-site, MS SQL, etc.)
- Laptop backup application - back up files and folders on the desktop, or in folders other than the "my documents" folder
- Implement Phase II NERC public web-site upgrade. Multi-lingual support, Business Intelligence capabilities, mobile support, enhanced user management, etc.
- (Multi-year effort) Reduce backlog of 95+ NERC and ERO projects currently identified as business needs to the Project Management Office.
- Re-write ERO Membership Service Agreement application, which is a specialized version of the NERC My Account described below. The ERO Membership Service Agreement application captures additional information that may not be required by the NERC My Account Service.
- Re-write NERC My Account Service Agreement application, which is a single user account that, when granted rights, allows the user to request access to multiple secured NERC sites. The registration process collects the required information from the requestor to allow the NERC resource to vet the request and determine if the requestor should be granted access to the requested secure site.
- Re-write User Management Program (UMP) Service Agreement application. UMP provides external persons who need or desire access to NERC tools a way to request approved access. The UMP application is archaic in its approach to delivery of user access and rewriting the application using SharePoint 2010 will greatly reduce NERC employee manual input.

## Resource Requirements

To accomplish the goals and objectives described above, additional resources will be required as further described below.

### Personnel

In 2012 three positions ~~transferred~~ which were previously under the Chief Reliability Officer and allocated among several Program Areas were transferred to the Information Technology department when the Chief Reliability Officer position was eliminated. The reason for this transfer was based on an independent consultant's recommendation as part of a corporate process improvement initiative to create a Project Management Office (PMO) within the Information Technology department. The PMO is responsible for managing the identification, prioritization, design and deployment of IT applications supporting various departmental business needs, as well as supporting the common IT business needs of NERC and the Regional Entities. The individuals who were transferred were each involved in ~~with~~ the management of IT applications supporting various program areas, including compliance database and standards

balloting redesign, as well as process improvement and enterprise architecture redesign initiatives. Only one additional Information Technology resource will be added in 2013, a SharePoint Administrator / Developer with responsibility for developing business applications in SharePoint 2010 and Visual Studio 2010. The role will be a dual capacity function and will need to possess strong SharePoint administration background along with experience developing and maintaining Enterprise class applications in a SharePoint environment. The role will be instrumental in replacing several internal NERC applications to increase efficiency and productivity. The role will also be leveraged to ensure ERO Enterprise class applications are designed consistent with SharePoint best practices.

In addition to the one (1) resource being added in 2013, the existing compliment of Information Technology resources are optimized following industry best practice for service support:

- Information Technology Support Center (ITSC) provides reactive support for help desk assistance for all NERC employees and requests as received from Entities for access to NERC resources.
- System and Network Administration. Senior level resources responsible for proactive support and strategic implementation of system, network and security across the enterprise.
- Development. Senior level resources responsible for designing and creating applications across NERC and the ERO to increase collaboration, reduce duplication of effort and improve data intelligence capabilities.
- Project Management. Junior and senior level resources responsible for gathering business requirements and translating into technology scope for creation by development or outsourcing as appropriate.

**Contractors and Consultants**

The following is a list of the 2013 budgeted contractor and consulting expenditures, the cost of which are set forth in Exhibit B. The overall 2013 budget for Consultants & Contracts represents a $1,303,000 increase over the 2012 budget.

- NERC website design-Major initiative to complete redesign and rewrite of the NERC public website using SharePoint 2010. The effort will entail usage of multiple contract resources with knowledge of SharePoint governance rules for document management; to include metadata tagging, quality assurance and exposure to the public facing website.
- Re-write ERO Membership Service Agreement application, which is a specialized version of the NERC My Account described below. The ERO Membership Service Agreement application captures additional information that may not be required by the NERC My Account Service.
- Re-write NERC My Account Service Agreement application, which is a single user account that, when granted rights, allows the user to request access to multiple secured

NERC sites. The registration process collects the required information from the requestor to allow the NERC resource to vet the request and determine if the requestor should be granted access to the requested secure site.

- Re-write User Management Program (UMP) Service Agreement application. UMP provides external persons who need or desire access to NERC tools a way to request approved access. The UMP application is archaic in its approach to delivery of user access and rewriting the application using SharePoint 2010 will greatly reduce NERC employee manual input.
- Security vulnerability testing-Ongoing intrusion detection and vulnerability testing of the NERC public website, NERC network and systems. Testing is conducted by an outside vendor using the latest intrusion techniques to test the security of the NERC network. Multiple attempts are made to gain access and any vulnerabilitiesy identified are documented and provided to NERC Information Technology for rapid remediation.
- Infrastructure design and integration-Hardware and software required to support development and ongoing NERC production activities. Multiple infrastructure items are targeted in the 2013 budget to include: server and laptop replacement, remote access, improved storage capability, Local and Wide area network monitoring and alerting, virtualization and consolidation.
- Compliance database-Redesign of the compliance database modules: Standards, Registration and Technical Feasibility Exception (TFE) using SharePoint 2010.
- Standards Balloting-Complete re-write of the Standards Balloting application using SharePoint 2010. The initial re-write and redesign of the application will be completed in 2012, but additional capability will be built into the application in 2013 for greater ease of commenting and response capability for Registered Entities.
- Project management, application development, support and maintenance (listed as Contractor Project Manager, Contractor Business Analyst and Contractor programming & development support on Exhibit B).
- Project management tools designed to track and monitor project, resource and budget adherence across NERC. The tool would also be used by the Standards team as a replacement for the existing tool which lacks core capability and functionality to track activities.
- Quality assurance testing-Quality Assurance (QA) for applications created by development or by outside contractors. The tool would allow for writing of QA scripts in plain English to test user screens for full functionality versus manual QA of the application. QA tools would greatly decrease coding errors and increase user satisfaction with the final product.
- Data warehouse design-A data warehouse is commonly used as a consolidated location for massive volumes of data. In this context a data warehouse would be created leveraging best of class hardware and consulting services to stream data into a consolidated database accessible across the ERO. The data warehouse would be

constructed in such a manner to build upon efforts started in 2012 to consolidate the multiple databases and streams of information into a consolidated warehouse allowing for the creation of applications and mining of data in a centralized repository for increased data sharing across a broad spectrum of disciplines e.g., RAPA, Compliance, Standards, etc.

- Common technology platform-Through collaboration and information sharing among NERC and the Regions a concentrated effort would be initiated to choose a best of class application designed to provide a secure, easy to use ERO application.
- Studies and assessments-Vendor studies and assessments that would be required in the event an application or database could not be delivered by NERC in-house development due to resource or time constraints. Studies and assessments are required in many instances to map out existing applications to the associated database and to gather technology requirements in order to scope the best technical solution for the business need.
- Disaster recovery-Hardware and applications required to set up an initial disaster recovery site as a backup option in the event the NERC primary data center is unavailable. Primary business tools such as critical grid alerting tools, Microsoft Exchange, remote telephony and other tools designed to ensure the continued operation of NERC business entities would be part of the initial design.
- Backup of electronic files-Purchase of greatly improved backup and recovery software designed to backup Microsoft Exchange, Laptop and Server data to meet retention and storage requirements.

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## 2013 IT Operating and Capital Expense Budget

As indicated above, 2013 IT planning was based on a multi-year strategy designed to reduce complexity, improve productivity and gain a consolidated view of data across the ERO. Several criteria were considered during the planning phase to include a NERC IT Architecture study conducted by Deloitte and Touche in Q4/2011, the need for visibility to aggregate data across the ERO and vastly improved collaboration among NERC and the Regions.
The NERC IT Architecture study determined that many of the ERO applications designed in prior years were shown to be in silos and unable to look across multiple disciplines in order to obtain an aggregate view of events or trending across the grid. Implementation of enterprise-class tools such as SharePoint, SQL Server 2008, Virtualization and centralized data warehouse capability was deemed critical to provide greater productivity and efficiency, enhanced visibility to data and vastly improved collaboration.

In addition to setting the stage for implementation of core technologies in 2013, IT initiatives in 2012 were built using industry-standard best practices designed to build upon many of the recommendations of the Deloitte and Touche IT Architecture study. Tools such as SharePoint 2010, workflow automation - K2 Black Pearl in addition to best practices for centralized management and methodology through the Project Management Office, along with development,

Quality Assurance and Production build the framework for 2013 operating and capital budget request described in greater detail below.
The 2013 IT operating and capital budget builds on industry best-practices and are focused on greater visibility, accountability and reliability of data across multiple disciplines.

## 2013 IT Operating Expenses

A summary of the major categories of IT Operating Expenses are set forth in the following table followed by a discussion.

| Office Costs | Budget 2013 |
|---|---|
| Telephone | $ 175,000 |
| Internet | 335,000 |
| Computer Supplies and Maintenance | |
| Computers | 3,000 |
| Computer Supplies | 116,900 |
| Maintenance & Service Agreements | 1,226,325 |
| Software | 37,500 |
| **Total Office Costs** | **$ 1,893,725** |

]

[Susan- insert table with summary of major operating expense categories and amounts

- **Telephone**

Office telephone costs are items associated with cellular phone, mobile laptop cellular air card, bonded T1 Voice over Internet Protocol (VoIP) data circuits and conference calling expenses.

- NERC-issued cell phones are provided to employees to ensure access and productivity before, during and after business hours and cost is minimized by leveraging pooled minutes. Individual NERC employees are provided with a basic pooled cell phone plan of 450 minutes including a basic-level subscription for texting and data. This plan is designed to ensure persons who travel frequently have additional cell phone minutes, by taking advantage of limited usage by employees who travel less frequently. In addition, employees are encouraged to connect via wireless whenever possible to reduce cellular charges for data usage. The basic texting plan is provided for those instances when calling or email is not optimal. Cellular calling cost are included in the telephone expense item.
- Mobile laptop cellular air cards are provided to ensure connectivity while traveling or in locations where wireless connectivity is unavailable. Employees are encouraged whenever possible to connect via wireless versus cellular to reduce usage fees. Wireless or cellular connectivity to the NERC network is enabled using virtual private network technology to ensure maximum security, logging and encryption.
- Information Technology support persons are required to be available for support 24x7x365 that in almost all instances requires access to systems and network via secure internet connectivity. Included in the line item "telephone" are those monthly cost associated with internet access for systems, application, network and security to enable IT resources to provide support, conduct emergency and non-emergency patching of systems, routers, firewalls, etc., as required to ensure the stability of the NERC technology environment.
- Conference calling is conducted via an external service provider in order to minimize internal hardware, Information Technology support, and internal conference lines capable

of providing access to an external audience. Information Technology conference calling, webinars, recorded events, etc., are included in the telephone cost line item.

- Bonded T1 circuits provide access for VoIP service for NERC desk phones in lieu of having a very expensive, support intensive in-house phone switch (e.g., Private Branch Exchange) that requires senior-level telecommunication resources to support and manage.

~~**Telephone Answering Service**~~

~~The telephone answering service is provided by an external service provider responsible for fielding initial after hours (holidays, weekend, after business hours) support calls for IT assistance. The service provider will gather basic information in order to rapidly ensure resolution of LAN/WAN, Server, Application, Internet/Intranet, laptop, cellular phone, etc., support from the appropriate IT resource.~~

- **Internet Expense - $335,000**

Internet expense is comprised of data circuits, Plain old Telephone Service (POTS), and redundant capability in the event of primary service provider failure. Individual detail is outlined below:

- Atlanta Headquarters (HQ). The Atlanta HQ office is connected to Washington DC and the offsite Co-Location data center via direct (metro-E) data circuits and via backup internet and secondary carrier. In the event of a primary circuit failure, the HQ location automatically fails over to a secondary circuit in order to access over one hundred (100) servers, network devices, intrusion protection and detection, firewall, routers and switches located at the co-location data center. Co-location was chosen to minimize cost associated with adding, maintaining, cooling, fire protection, etc., of a NERC-owned data center. NERC employees must have connectivity (via primary and secondary) to the co-location facility in order to access all industry, back-office and office productivity applications. Internet connectivity, in addition to providing limited access in the event of primary and secondary carrier failure is used to ensure access by remote users e.g., VPN connected laptops, etc., in order to access NERC computer resources.
- Washington DC. The Washington DC office has similar connectivity back to the co-location data center located in Atlanta Georgia. The DC office connectivity is primarily via high speed remote private circuit with backup connectivity to the Atlanta HQ location in the event of a primary circuit failure. The DC office also has internet access in a similar fashion to the HQ location.
- NERCNet Data circuits between the Carteret New Jersey data center and the Atlanta co-location facility are included in the internet expense line item to ensure primary and secondary connectivity for NERCNet nodes.
- POTS Lines and bonded T1 data service are leveraged to provide access for conference calling and for internal desk phones. POTS lines have been installed in each conference room to be used for conference calling to ensure maximum voice quality due to the magnitude of calls conducted, number of external audio and video members and reliability.

~~**Office Supplies**~~

~~Routine office supplies such as pens, paper, desk calculators, CD's etc., are categorized under this line item.~~

- **Computers**

Computers are items that do not meet the criteria considered a capital expense such as desktop computers or iPads. Desktop computers enable conference webinars, internet access, training room functionality, etc., for those instances when a presenter does not have a computer device

available to conduct presentations. In addition, NERC will on a case-by-case basis and as justified by extensive travel or consistent out of office meetings provide an iPad with cellular data access for persons who require functionality but are unable to use a laptop for computing needs.

- **Computer Supplies**

Computer supplies are expense items required for infrastructure support to include computer monitors, mice, keyboard, cell phones, cables, encrypted hard drives, encrypted thumb drives, encryption keys, uninterruptible power supplies (UPS), privacy screens, phone headsets, docking stations, computer memory and any other computer supplies or components required to support the technology infrastructure.

- **Maintenance and Service Agreements**

Maintenance and Service Agreements comprise those items required to support internal and external access to routers, switches, firewalls, intrusion protection, 100-fileservers, audio visual, storage area network, data backup services, network and security monitoring, co-location data center services, video conferencing, digital certificates, development and virtualization software. Service agreements related to the co-location data center, offsite backup of over 100-terabytes of data, conference calling, network and security monitoring consume a large portion of the maintenance and service agreements budget. Additional detail is provided here:

- Co-location data center. NERC leverages a co-location facility in order to minimize the cost associated with maintenance, support and resources required to maintain a fixed data center. Infrastructure such as redundant UPS, cooling, carrier diversity, physical security, generator and raised computer flooring are contained within the co-location facility where NERC houses the majority of computing resources for the Atlanta HQ and Washington DC office.
- Offsite backup. NERC ensures reliability and consistency of over 100-terabytes of data storage by leveraging an offsite backup service provider. Data is streamed from disk to an offsite hardened storage facility capable of providing data backup and restoration based upon retention and storage procedures.
- Conference calling services. Conference calling services are provided by an external service provider designed to minimize the need for an internal conference bridge or associated hardware and support persons. NERC conducts several hundred industry focused conference calls, webinars, training etc. per year and in order to ensure consistency and reliability conference calling service by an external provider was chosen.
- Network monitoring. Network monitoring is real time by industry leading tools designed to proactively alert network resources of network degradation, equipment failure, or loss of connectivity. Network monitoring is utilized to ensure the stability, security and reliability of the NERC network primary and secondary Wide Area Network (WAN) and internal Local Area Network (LAN) connections.
- Security monitoring. Monitoring is provided by an industry recognized leader in security monitoring and implementation of best practices.

- **Software**

Software expense is made up of those items that are not covered under the standard Microsoft Enterprise Agreement (EA). Items such as Lyris Listserv licenses, Matricon, SolarWinds, KACE (support desk), Visio, Script Logic, K2-Blackpearl, Modeling software (PSLF), etc., required in support of back-office and development of both internal NERC and ERO applications.

~~**Subscriptions and Publications**~~

~~Specific IT subscriptions and publications deemed necessary to ensure the stability, effectiveness and efficiency of the technology environment are contained under this expense category.~~

~~**Express Shipping**~~

~~Express shipping is in support of persons traveling or in those scenarios where immediate delivery of a phone, laptop, monitor or other device is required. Considerable effort is made to leverage cost effective, timely delivery methods. Or, as deemed appropriate and in adherence to IT standards, employees are encouraged to obtain non-standard impacting items via local vendor e.g., mice, keyboard, etc., that will not have an adverse impact on support.~~

## 2013 IT Fixed Asset (Capital) Expenses

| Fixed Assets | Budget 2013 |
|---|---|
| Computer & Software CapEx | |
| Data Warehouse and ERO Single Application | $ 600,000 |
| Disaster Recovery | 300,000 |
| Data Back-up and Storage | 100,000 |
| Laptops for New Staff and Replacement | 174,000 |
| Development Servers | 115,000 |
| Software | 267,100 |
| Total Computer & Software CapEx | 1,556,100 |
| | |
| Equipment CapEx | |
| Network Devices | $ 216,000 |

In order to provide access, visibility and analysis of data from many different sources across the ERO, it will require significant investment in hardware, software and associated tools and technology. The overarching theme is to gain a holistic view of data across the enterprise in support of reliability and accountability of the bulk power system. Adding capability to centralize and mine data, in addition to foundational elements such as disaster recovery and application development, set the stage for vastly improved reporting, business intelligence and capability for collaboration and sharing of information vital to the ERO's mission.

Among the significant investments required to support efficiency and consistency across the enterprise listed in the 2013 budget draft include Data Warehouse, ERO single application infrastructure, Disaster Recovery (DR) and associated virtualization, network, server hardware and software that consume a large portion of the OPEX/CAPEX expenditure in 2013. In addition, internal NERC environmental upgrades are required which include servers, laptops, back up and associated hardware items.

The major categories of 2013 IT Fixed Asset (aka Capital Expense) are ~~set forth in the table below followed by a discussion of each of these major categories~~computer and software and equipment.

| Fixed Assets | | |
|---|---|---|
| Computer & Software CapEx | | 1,952,190.00 |
| Furniture & Fixtures CapEx | | |
| Equipment CapEx | | 241,000.00 |
| Leasehold Improvements | | |
| Incr(Dec) in Fixed Assets | | 2,193,190.00 |

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- **Data Warehouse Hardware**

A data warehouse is a repository of data, designed to provide a reliable, stable, secure environment for reporting across multiple disciplines (e.g., RAPA, Compliance, Standards, Enforcement, etc.) and requires a significant investment in large scale database and storage architecture.

As illustrated by the IT Architecture Project conducted by Deloitte and Touche conducted in Q1, 2012, NERC and the Regions have many disparate sources of data, none of which are closely integrated for a holistic view across the enterprise. Implementation of a centralized data warehouse, through collaboration and consensus with the Regions, will build upon to-be-defined data input from multiple sources (e.g., Events Analysis, TADS, GADS, DADS, CRATS, etc.), providing an aggregate view across the enterprise. Design of a data warehouse is a multi-year effort that requires significant investment in hardware to store incoming transactional data from disparate data sources into a hierarchal structure targeted at building a single source of secure, reliable information. Alignment of data from disparate sources is a foundational element required to build the framework for business intelligence tools to mine data across the enterprise, build executive dashboards and establish long term trending and analysis.

- **ERO Single Application Infrastructure Hardware**

SharePoint 2010 is the tool of choice for reliable, secure, efficient, and cost effective sharing of information and collaboration with the Regional Entities and external stakeholders. SharePoint 2010 is a robust web application platform capable of supporting multiple organizations that can be coupled with third party solutions such as Enterprise Resource Planning (ERP), Customer Relationship Management (CRM) and Business Intelligence (BI) tools as required by the ERO. Implementation of SharePoint 2010 sets the foundation for integration with the Regions through creation of web portals and applications designed to reduce the complexity associated with document sharing, data mining and improved productivity by reducing the need to combine data from multiple sources onto spreadsheets.

A clear example of improved efficiency is the concept developed to use SharePoint to tie violation documents to the violation. Previously there were no automated mechanisms to associate the violation record with the violation data, resulting in considerable manual effort by the Enforcement team. Through collaboration and consensus with the Regions, a concept was developed to automate the process through implementation of SharePoint document management. Further capability through claims-based management builds the framework to reduce numerous spreadsheet applications for much greater productivity and enhanced design capabilities.

In order to implement SharePoint on an enterprise scale, investment in hardware (servers), network (routers, firewalls, switches) and virtualization software is required to promote collaboration and consistency across the ERO.

- **Disaster Recovery Hardware**

Implementation of a disaster recovery plan to include hardware in support of critical IT resources (e.g.., Exchange email, NERC forward facing web-site, MS SQL, etc.) is imperative for NERC in 2013. Disaster recovery is a multi-year effort that will entail both plan creation and purchase of associated hardware.

Disaster recovery is designed to put the initial framework in place to ensure survivability of the most critical assets required to sustain ERO functions. Items such as payroll, accounting, exchange messaging, internet access and phone service fall into items considered critical-to-business-operations, in addition to other applications considered necessary for the reliability of

the grid. The initial implementation would be based on a risk assessment conducted by IT, assisted by external vendors and the business to determine those items deemed most critical to the ERO's mission.

Implementation of a disaster recovery plan is a multi-year endeavor that will require continuous tuning and testing to ensure all facets of the plan are well-scripted and understood to ensure that staff, vendors and Regional Entities are prepared to enact upon declaration of a disaster event. Initial steps in 2013 include plan creation and procurement of hardware in support of essential business functions.

- **Laptop Replacement Hardware**

NERC issued laptop computers are on a three year depreciation cycle and are rotated out as they are determined to have reached the end of the productive business cycle. Each year during the business planning and budget cycle an analysis is conducted to determine those computers that are coming due for refresh and the associated number are accounted for in the planning cycle. Throughout the year computers are refreshed as their warranty expires, or they have been determined to no longer provide effective business functions.

- **Servers, Network and Storage Area Network Hardware**

Servers located at the co-location data center are on a five year depreciation cycle designed to take advantage of the longer operational life of server equipment versus laptop equipment. Approximately 80 servers are located at the co-location data center and an analysis is conducted each year to determine those devices that are near, or at the end of the five year cycle. Servers that have been determined to no longer provide useful business functions are refreshed following the five year cycle or sooner if their operational capacity has been exceeded to lack of expansion capability.

Network equipment such as routers, switches, firewalls, intrusion detection and protection devices are on a similar depreciation schedule as the server equipment discussed above. Each device is designed with expansion capability in mind and is tailored to serve the ever growing demand for network bandwidth and access to vital data in support of the ERO's mission.

Storage Area Network (SAN) equipment is also located at the co-location data center and is where most data is housed. The SAN equipment is a multi-terabyte storage device with several layers of redundancy to effectively store and protect NERC information.

- **Data Backup and Storage**

NERC data and information located at the co-location data center is continually backed up using a data service and appliances to back up the information to disk and then to an off-site storage location. Data is backed up every 15 minutes and follows industry best-practice for daily, weekly, monthly, quarterly and yearly backup cycles. The data is encrypted in transit and maintained following NERC established retention policies. Additional hardware will be required to backup the massive amount of ERO data anticipated for the Data Warehouse and associated environment e.g., SharePoint collaboration sites, in addition NERC laptops and desktops.

- **Development**

Utilizing recommendations from the Deloitte and Touche "IT Architecture" study conducted in Q4/ 2011, NERC embarked upon an aggressive strategy to design and implement a development strategy following industry best practice for application development. Implementation of a development, QA and production environment sets the stage, in collaboration with the Regions and PMO to create consistent applications deemed strategic to the ERO. A survey of NERC and the Regions identified 95 applications either in use, or items

requested in support of ERO functions. In order to reduce the backlog of those applications deemed strategic to the ERO, it will require a concentrated effort by NERC, the Regions and contract and consultant resources working in concert to conduct in-depth business analysis of requirements, development of request for proposal and consideration of in-house development, or outsourced development by contract and consultant resources, as applicable. Several of the applications identified during the survey are substantial in nature and will require a multi-year approach to define, develop and implement throughout the ERO. As applications are defined, additional development, QA and production hardware will be required to enhance the virtual environment.

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**Statement of Activities, Fixed Assets Expenditures and Change in Working Capital**
**2012 Budget & Projection, and 2013 Budget**
**INFORMATION TECHNOLOGY**

| | 2012 Budget | 2012 Projection | Variance 2012 Projection v 2012 Budget Over(Under) | 2013 Budget | Variance 2013 Budget v 2012 Budget Over(Under) | 2013 Budget Draft 1 | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|---|---|
| **Funding** | | | | | | | |
| **ERO Funding** | | | | | | | |
| NERC Assessments | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Penalty Sanctions | | | | - | | - | - |
| **Total NERC Funding** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Membership Dues | - | - | - | - | - | - | - |
| Testing Fees | - | - | - | - | - | - | - |
| Services & Software | - | - | - | - | - | - | - |
| Workshops | - | - | - | - | - | - | - |
| Interest | - | - | - | - | - | - | - |
| Miscellaneous | - | - | - | - | - | - | - |
| **Total Funding (A)** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Expenses** | | | | | | | |
| **Personnel Expenses** | | | | | | | |
| **Salaries** | $ 1,412,180 | $ 1,612,122 | $ 199,943 | $ 1,714,413 | $ 302,234 | $ 1,764,923 | (50,510) |
| **Payroll Taxes** | 100,329 | 109,511 | 9,182 | 118,416 | 18,087 | 119,231 | (815) |
| **Benefits** | 204,053 | 181,000 | (23,053) | 219,003 | 14,951 | 219,032 | (29) |
| **Retirement Costs** | 203,123 | 187,211 | (15,912) | 187,078 | (16,045) | 198,886 | (11,808) |
| **Total Personnel Expenses** | $ 1,919,684 | $ 2,089,844 | $ 170,160 | $ 2,238,910 | $ 319,226 | $ 2,302,072 | (63,162) |
| **Meeting Expenses** | | | | | | | |
| **Meetings** | $ - | $ 132 | $ 132 | $ 5,000 | $ 5,000 | $ - | 5,000 |
| **Travel** | 26,750 | 60,000 | 33,250 | 62,000 | 35,250 | 26,750 | 35,250 |
| **Conference Calls** | 4,800 | 4,800 | - | 4,800 | - | 4,800 | - |
| **Total Meeting Expenses** | $ 31,550 | $ 64,932 | $ 33,382 | $ 71,800 | $ 40,250 | $ 31,550 | 40,250 |
| **Operating Expenses** | | | | | | | |
| **Consultants & Contracts** | $ 1,418,000 | $ 1,663,027 | $ 245,027 | $ 2,721,000 | $ 1,303,000 | $ 2,721,000 | - |
| **Office Rent** | - | - | - | - | - | - | - |
| **Office Costs** | 1,898,470 | 1,898,470 | - | 1,893,725 | (4,745) | 1,898,470 | (4,745) |
| **Professional Services** | - | 5,154 | 5,154 | 500 | 500 | - | 500 |
| **Miscellaneous** | 1,600 | 4,264 | 2,664 | 1,000 | (600) | 1,600 | (600) |
| **Depreciation** | 1,360,275 | 927,129 | (433,146) | 1,123,002 | (237,273) | 1,360,275 | (237,273) |
| **Total Operating Expenses** | $ 4,678,345 | $ 4,498,045 | $ (180,300) | $ 5,739,227 | $ 1,060,882 | $ 5,981,345 | $ (242,118) |
| **Total Direct Expenses** | $ 6,629,579 | $ 6,652,821 | $ 23,242 | $ 8,049,937 | $ 1,420,358 | $ 8,314,967 | $ (265,030) |
| **Indirect Expenses** | (6,629,579) | $ (6,652,821) | $ (23,242) | $ (8,049,937) | $ (1,420,358) | $ (8,314,967) | $ 265,030 |
| **Other Non-Operating Expenses** | $ - | $ - | $ - | $ - | $ - | $ - | - |
| **Total Expenses (B)** | $ 0 | $ - | $ (0) | $ - | $ (0) | $ - | $ - |
| **Change in Assets** | $ (0) | $ - | $ 0 | $ - | $ 0 | $ - | - |
| **Fixed Assets** | | | | | | | |
| Depreciation | (1,360,275) | (927,129) | 433,146 | (1,123,002) | 237,273 | (1,360,275) | 237,273 |
| Computer & Software CapEx | 772,090 | 772,090 | - | 1,556,100 | 784,010 | 1,952,190 | (396,090) |
| Furniture & Fixtures CapEx | - | - | - | - | - | - | - |
| Equipment CapEx | - | 32,293 | 32,293 | 216,000 | 216,000 | 241,000 | (25,000) |
| Leasehold Improvements | - | - | | - | - | - | - |
| Allocation of Fixed Assets | $ 588,185 | $ 122,746 | (465,439) | $ (649,098) | $ (1,237,283) | $ (832,915) | 183,817 |
| **Inc(Dec) in Fixed Assets ( C )** | $ - | $ - | $ - | $ - | $ - | $ - | $ 183,817 |
| **TOTAL BUDGET (=B + C)** | $ 0 | $ - | $ (0) | $ - | $ (0) | $ - | |
| **TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)** | $ (0) | $ - | $ 0 | $ - | $ 0 | $ - | $ - |
| **FTEs** | 12.75 | 15.49 | 2.74 | 16.75 | 4.00 | 16.75 | - |

## Summary of Variances by Category – 2013 Budget Compared to the 2012 Budget

- Personnel Expense – Salaries, Payroll Taxes and Benefits costs are increasing due to the increase in FTEs in the department, but due to the change in NERC's retirement plan, the average cost per FTE resulted in a decrease in costs in 2013.
- Consultants and Contracts – The increase is described in detail above.
- Fixed Assets – The increase is described in detail above.

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## Human Resources

| Human Resources (in whole dollars) | 2012 Budget | 2013 Budget | Increase (Decrease) | 2013 Budget - Prior Draft | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|
| Total FTEs | 6.00 | 3.00 | (3.00) | 3.00 | - |
| Total Direct Expenses | $ 1,444,141 | $ 1,276,845 | $ (167,296) | 1,233,137 | 43,708 |
| Inc(Dec) in Fixed Assets | $ - | $ - | $ - | | - |
| Working Capital Requirement | $ - | $ - | $ - | | - |

### Background and Scope

The Human Resources area manages all of NERC's human resources functions, including new-hires, benefits, and employee functions. This area also oversees NERC's employee performance appraisal and incentive structure process. In 2010, NERC implemented a more robust, objective and auditable performance management system to track corporate, departmental and individual performance against pre-established goals, objectives and measures. Each year NERC continues to refine and improve this system. In 2011 it became fully automated. In 2012 NERC implemented a new time accounting system to facilitate tracking of time by functional activities or, where appropriate, specific projects.

### 2013 Goals and Objectives

#### Executive Training and Development

As the NERC risk-based methodology to improve reliability is further developed and deployed, experienced consultants will be used to provide strategic guidance and training for the executive team to frame problems according to highest potential risk factors and prioritize to solve big issues. The executive leadership team may also receive additional training and development initiatives geared towards promoting collaboration and consensus-building to improve knowledge-sharing and coordinated efforts on solving big reliability issues.

#### Staff Development

Management believes that access to knowledge is a key differentiator for NERC, ensures retention and high performance, and NERC therefore will invest in learning opportunities for staff in several areas. First, HR will continue to host and optimize an ~~best-of-breed~~ e-leaning platform, SkillSoft, to provide staff resources for improving soft and technical skills. Second, HR will provide staff development training though real-world access via tours of and training on control centers, electric substations, and power plants. Finally, staff will have access to additional education including but not limited to degree-oriented university education, pursuit of specialized certifications, and other in-house and external training that provides essential knowledge and skills development that will lead to improved staff performance.

#### Compensation Consulting

HR will continue to rely on market data to drive its attraction, engagement, and retention model. Periodically, HR will have ~~Mercer~~a compensation consultant examine the ~~real-time accuracy of~~current market data to ensure that all decisions affecting compensation are made in ~~deference to~~light of the current market climate and that ~~talent~~qualified employees are attracted and retained within a defined total remuneration range. To protect ~~our~~NERC's substantial investment in human capital, HR will also engage consultants to consider compensation models and practices prevalent within the market ~~and linked to~~that have been successful in attracting, engaging, and retaining talent. Similarly, HR may partner with compensation subject matter experts to perform periodic assessments of the BOT compensation model to ensure alignment with market practices. NERC's compensation policy and analysis of market data will be based on total remuneration, taking into account base and incentive compensation, as well as benefits.

**Surveys**

HR will ~~partner with an outside provider~~retain a vendor to ~~continue to provide best-of-breed~~ design stakeholder and other surveys, as well as to analyze survey results ~~consulting services~~. ~~In~~in the vendor will assist in identifying and implementing ~~addition to improving the~~improvements in the ~~design and analytics of and conducting the~~ BOT, MRC, and NERC Board of Trustees' ~~C~~committees surveys, as well as launch additional surveys including ~~ones for the~~ a (1) a CCC survey to evaluate industry's perspectives o~~f~~n NERC's effectiveness ~~of~~in improving reliability and ~~an~~(2) an internal employee climate survey.

**Succession Planning**

Critical to continued success towards ensuring the reliability of the bulk power system is minimizing disruption of knowledge/skill/experience bases of key staff. HR will partner with Talent Quest to leverage best practices and software tools to systemically identify essential roles and develop strategies to build pipelines and contingency plans for any loss of staff.

**HR Products and Services Automation**

Paramount to an effective/efficient HR department is the use of electronic and automated products and services. HR will continue development of a user-friendly, easy-to-access suite of HR solutions by continuing investment in electronic platforms. These investments include converting HR to a "paperless" function, launching a single sign on for employees whereby they can access all tools with one set of log-in credentials, adding additional capabilities including an online benefits enrollment system, and optimizing online time and attendance, training, and performance management tools.

## Resource Requirements

**Personnel**

Two FTEs transferred to other departments in 2012. In addition, Human Resources staffing will be reduced by one (1) FTE in 2013.

**Contractor Expenses**

Contractor and consultant expenses are roughly in line with 2012 budgeted amounts and are set forth in additional detail in Exhibit B.

**Statement of Activities, Fixed Assets Expenditures and Change in Working Capital**
**2012 Budget & Projection, and 2013 Budget**
**HUMAN RESOURCES**

| | 2012 Budget | 2012 Projection | Variance 2012 Projection v 2012 Budget Over(Under) | 2013 Budget | Variance 2013 Budget v 2012 Budget Over(Under) | 2013 Budget Draft 1 | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|---|---|
| **Funding** | | | | | | | |
| **ERO Funding** | | | | | | | |
| NERC Assessments | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Penalty Sanctions | | - | | - | | - | - |
| **Total NERC Funding** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Membership Dues | - | - | - | - | - | - | - |
| Testing Fees | - | - | - | - | - | - | - |
| Services & Software | - | - | - | - | - | - | - |
| Workshops | - | - | - | - | - | - | - |
| Interest | - | - | - | - | - | - | - |
| Miscellaneous | - | - | - | - | - | - | - |
| **Total Funding (A)** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Expenses** | | | | | | | |
| **Personnel Expenses** | | | | | | | |
| **Salaries** | $ 711,539 | $ 629,031 | $ (82,508) | $ 547,207 | $ (164,332) | $ 555,648 | (8,441) |
| **Payroll Taxes** | 37,353 | 28,227 | (9,126) | 23,187 | (14,166) | 23,309 | (122) |
| **Benefits** | 294,372 | 348,634 | 54,262 | 282,974 | (11,398) | 282,974 | - |
| **Retirement Costs** | 70,798 | 48,809 | (21,989) | 42,627 | (28,171) | 42,627 | - |
| **Total Personnel Expenses** | $ 1,114,062 | $ 1,054,701 | $ (59,361) | $ 895,995 | $ (218,067) | $ 904,558 | (8,563) |
| **Meeting Expenses** | | | | | | | |
| **Meetings** | $ 11,385 | $ 11,385 | $ - | $ 5,000 | $ (6,385) | $ 11,385 | (6,385) |
| **Travel** | 7,000 | 15,000 | 8,000 | 21,000 | 14,000 | 7,000 | 14,000 |
| **Conference Calls** | 600 | 1,000 | 400 | 600 | - | 600 | - |
| **Total Meeting Expenses** | $ 18,985 | $ 27,385 | $ 8,400 | $ 26,600 | $ 7,615 | $ 18,985 | 7,615 |
| **Operating Expenses** | | | | | | | |
| **Consultants & Contracts** | $ 290,000 | $ 246,324 | $ (43,676) | $ 288,500 | $ (1,500) | $ 288,500 | - |
| **Office Rent** | - | - | - | - | - | - | - |
| **Office Costs** | 13,094 | 24,000 | 10,906 | 42,500 | 29,406 | 13,094 | 29,406 |
| **Professional Services** | 5,000 | 5,000 | - | 18,250 | 13,250 | 5,000 | 13,250 |
| **Miscellaneous** | 3,000 | 3,000 | - | 5,000 | 2,000 | 3,000 | 2,000 |
| **Depreciation** | - | - | - | - | - | - | - |
| **Total Operating Expenses** | $ 311,094 | $ 278,324 | $ (32,770) | $ 354,250 | $ 43,156 | $ 309,594 | $ 44,656 |
| **Total Direct Expenses** | $ 1,444,141 | $ 1,360,410 | $ (83,731) | $ 1,276,845 | $ (167,296) | $ 1,233,137 | $ 43,708 |
| **Indirect Expenses** | $ (1,444,141) | $ (1,360,410) | $ 83,731 | $ (1,276,845) | $ 167,296 | $ (1,233,137) | $ (43,708) |
| **Other Non-Operating Expenses** | $ - | $ - | $ - | $ - | $ - | $ - | - |
| **Total Expenses (B)** | $ - | $ - | $ - | $ - | $ - | $ - | $ 0 |
| **Change in Assets** | $ - | $ - | $ - | $ - | $ - | $ - | - |
| **Fixed Assets** | | | | | | | |
| Depreciation | - | - | - | - | - | - | - |
| Computer & Software CapEx | - | - | - | - | - | - | - |
| Furniture & Fixtures CapEx | - | - | | - | - | - | - |
| Equipment CapEx | - | - | | - | - | - | - |
| Leasehold Improvements | - | - | | - | - | - | - |
| Allocation of Fixed Assets | $ - | $ - | $ - | - | - | $ - | - |
| **Inc(Dec) in Fixed Assets ( C )** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **TOTAL BUDGET (=B + C)** | $ - | $ - | $ - | $ - | $ - | $ - | |
| **TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **FTEs** | 6.00 | 4.00 | | 3.00 | (3.00) | 3.00 | - |

Summary of Variances by Category – 2013 Budget Compared to the 2012 Budget

- Personnel Expense – The decrease is due to having 3.0 fewer FTEs in the department in 2013.
- Travel – The increase in travel is related to time spent in the Washington, DC office and to quarterly Board of Trustee meetings.

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- Office Costs – The increase is due to annual maintenance fees for software that provides employee training courses.
- Professional Services – The increase is related to implementation of a third-party Human Resources Information System that provides employees access to all their payroll and benefit information through an online system.

## Finance and Accounting

| Accounting and Finance (in whole dollars) | 2012 Budget | 2013 Budget | Increase (Decrease) | 2013 Budget - Prior Draft | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|
| Total FTEs | 9.00 | 11.00 | 2.00 | 11.00 | - |
| Total Direct Expenses | $ 1,872,296 | $ 2,136,204 | $ 263,908 | 2,062,888 | 73,316 |
| Inc(Dec) in Fixed Assets | $ (771) | $ (798) | $ (27) | (771) | (27) |
| Working Capital Requirement | $ 0 | $ - | $ (0) | | - |

### Background and Scope

NERC's Finance and Accounting department manages all finance and accounting functions, including employee payroll, 401(k) and 457(b) plans, travel and expense reporting, monthly financial reporting, sales and use tax, meeting/events planning and services, insurance, internal auditing, and facilities management. This area also holds primary responsibility for the development of the annual business plan and budget, as well as NERC's proposed ERO risk management framework. Over the past several years, NERC's Finance and Accounting department implemented additional policies, procedures and controls governing day to day practices including contract and personnel procurements, meeting, conference planning and travel, expense reimbursement and back office systems and procedures. The department will continue to refine, improve and where necessary implement additional procedures and controls.

### Resource Requirements

#### Personnel

One (1) FTE was added in 2012 to provide facilities management and one (1) FTE was added in 2012 to provide additional adminstrative and internal controls support. No new FTE additions are planned for 2013.

#### Contractor and Consulting Expenses

$325k is budgeted for outside auditors to support audit program review and Regional Entity oversight by the the Compliance Operations and Critical Infrastrucure Protection departments as part of the internal controls and risk management function. The budget is consistent with 2012. To the extent that consulting support is required address regulatory directives affecting ~~the company~~NERC's financial, accounting, budgeting processes and/or systems these additional

costs will be ~~paid for~~funded from ~~working capital~~operating reserves in accordance with the company's approved Working Capital and ~~Contigency~~ Operating Reserve Guidelines.

**Statement of Activities, Fixed Assets Expenditures and Change in Working Capital**
**2012 Budget & Projection, and 2013 Budget**
**FINANCE and ACCOUNTING**

| | 2012 Budget | 2012 Projection | Variance 2012 Projection v 2012 Budget Over(Under) | 2013 Budget | Variance 2013 Budget v 2012 Budget Over(Under) | 2013 Budget Draft 1 | Variance to Prior Draft Over(Under) |
|---|---|---|---|---|---|---|---|
| **Funding** | | | | | | | |
| **ERO Funding** | | | | | | | |
| NERC Assessments | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Penalty Sanctions | | | - | - | - | - | - |
| **Total NERC Funding** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Membership Dues | - | - | - | - | - | - | - |
| Testing Fees | - | - | - | - | - | - | - |
| Services & Software | - | - | - | - | - | - | - |
| Workshops | - | - | - | - | - | - | - |
| Interest | - | - | - | - | - | - | - |
| Miscellaneous | - | - | - | - | - | - | - |
| **Total Funding (A)** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Expenses** | | | | | | | |
| **Personnel Expenses** | | | | | | | |
| **Salaries** | $ 1,023,527 | $ 1,205,998 | $ 182,471 | $ 1,209,534 | $ 186,007 | $ 1,215,505 | (5,971) |
| **Payroll Taxes** | 64,896 | 68,416 | 3,520 | 69,783 | 4,887 | 69,833 | (50) |
| **Benefits** | 142,111 | 131,852 | (10,259) | 141,784 | (327) | 141,771 | 13 |
| **Retirement Costs** | 144,750 | 126,396 | (18,354) | 140,105 | (4,645) | 138,768 | 1,337 |
| **Total Personnel Expenses** | $ 1,375,285 | $ 1,532,662 | $ 157,378 | $ 1,561,206 | $ 185,922 | $ 1,565,877 | (4,671) |
| **Meeting Expenses** | | | | | | | |
| **Meetings** | $ 500 | $ 500 | $ - | $ 5,000 | $ 4,500 | $ 500 | 4,500 |
| **Travel** | 40,000 | 40,000 | - | 62,500 | 22,500 | 40,000 | 22,500 |
| **Conference Calls** | 1,850 | 1,850 | - | 1,850 | - | 1,850 | - |
| **Total Meeting Expenses** | $ 42,350 | $ 42,350 | $ - | $ 69,350 | $ 27,000 | $ 42,350 | 27,000 |
| **Operating Expenses** | | | | | | | |
| **Consultants & Contracts** | $ 325,000 | $ 331,923 | $ 6,923 | $ 325,000 | $ - | $ 325,000 | - |
| **Office Rent** | - | - | - | - | - | - | - |
| **Office Costs** | 8,790 | 22,402 | 13,612 | 28,500 | 19,710 | 8,790 | 19,710 |
| **Professional Services** | 120,000 | 120,000 | - | 150,350 | 30,350 | 120,000 | 30,350 |
| **Miscellaneous** | 100 | 100 | - | 1,000 | 900 | 100 | 900 |
| **Depreciation** | 771 | 798 | 27 | 798 | 27 | 771 | 27 |
| **Total Operating Expenses** | $ 454,661 | $ 475,223 | $ 20,562 | $ 505,648 | $ 50,987 | $ 454,661 | $ 50,987 |
| **Total Direct Expenses** | $ 1,872,296 | $ 2,050,235 | $ 177,940 | $ 2,136,204 | $ 263,909 | $ 2,062,888 | $ 73,316 |
| **Indirect Expenses** | $ (1,872,296) | $ (2,050,235) | $ (177,939) | $ (2,136,204) | $ (263,908) | $ (2,062,888) | $ (73,316) |
| **Other Non-Operating Expenses** | $ - | $ - | $ - | $ - | $ - | $ - | - |
| **Total Expenses (B)** | $ (0) | $ - | $ 0 | $ - | $ - | $ - | $ (0) |
| **Change in Assets** | $ 0 | $ - | $ (0) | $ - | $ - | $ - | - |
| **Fixed Assets** | | | | | | | |
| Depreciation | (771) | (798) | (27) | (798) | (27) | (771) | (27) |
| Computer & Software CapEx | - | - | | - | - | - | - |
| Furniture & Fixtures CapEx | - | - | | - | - | - | - |
| Equipment CapEx | - | - | | - | - | - | - |
| Leasehold Improvements | - | - | | - | - | - | - |
| Allocation of Fixed Assets | $ 771 | $ 798 | $ 27 | 798 | 27 | $ 771 | 27 |
| **Inc(Dec) in Fixed Assets ( C )** | $ - | $ - | $ - | $ - | $ - | $ - | $ 27 |
| **TOTAL BUDGET (=B + C)** | $ (0) | $ - | $ 0 | $ - | $ - | $ - | |
| **TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)** | $ 0 | $ - | $ (0) | $ - | $ - | $ - | $ - |
| **FTEs** | 9.00 | 10.96 | | 11.00 | 2.00 | 11.00 | - |

## Summary of Variances by Category – 2013 Budget Compared to the 2012 Budget

- Personnel Expenses – Salaries , Payroll Taxes and Benefits expenses are projected to increase in 2013 due to adding 2.0 FTEs, but the change to NERC's retirement plans reduced Retirement Costs per FTE and resulted in a projected decrease in 2013.

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# Section B — Supplemental Financial Information

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## Reserve Balance

**Table B-1**

| Working Capital Reserve Analysis 2012-2013<br>STATUTORY | | 2013 Budget<br>Draft 1 | Variance to Prior Draft<br>Over(Under) |
|---|---|---|---|
| **Beginning Working Capital Reserve (Deficit), December 31, 2011** | 3,836,372 | 3,836,372 | 0 |
| Plus: 2012 Funding (from LSEs or designees) | 50,661,271 | 50,661,271 | - |
| Plus: 2012 Other funding sources | 2,386,285 | 2,386,285 | - |
| Less: 2012 Projected expenses & capital expenditures | (52,068,232) | (51,030,292) | (1,037,940) |
| **Projected Working Capital Reserve (Deficit), December 31, 2012** | **4,815,696** | **5,853,636** | **(1,037,940)** |
| **Desired Working Capital Reserve, December 31, 2013** [1] | 4,565,696 | 5,603,636 | (1,037,940) |
| Minus: Projected Working Capital Reserve, December 31, 2012 | 4,815,696 | 5,853,636 | (1,037,940) |
| **Increase(decrease) in funding requirement to achieve Working Capital Reserve** | (250,000) | (250,000) | 0 |
| 2013 Expenses and Capital Expenditures | 53,893,332 | 54,045,046 | (151,714) |
| Less: Penalty Sanctions [2] | (2,412,500) | (2,412,500) | - |
| Less: Other Funding Sources | (2,333,500) | (2,201,000) | (132,500) |
| Adjustment to achieve desired Working Capital Reserve | (250,000) | (250,000) | - |
| **2013 NERC Assessment** | 48,897,332 | 49,181,546 | (284,214) |

[1] On XXXXX XX, 2012, the Finance and Audit Committee of the NERC Board of Trustees approved management's proposed 2013 business plan and budget which included a projected year end working capital reserve of approximately $xxxx.

[2] Represents collections on or prior to June 30, 2012.

## Breakdown by Statement of Activity Sections

The following detailed schedules are in support of the consolidated Statement of Activities. All significant variances have been disclosed by program area in the preceding pages.

## Penalty Sanctions

Penalty monies received prior to June 30, 2012 are to be used to offset assessments in the 2013 Budget, as documented in the NERC Policy – Accounting, Financial Statement and Budgetary Treatment of Penalties Imposed and Received for Violations of Reliability Standard, as well as Section 1107 of the Rules of Procedure. Penalty monies received from July 1, 2012 through June 30, 2013 will be used to offset assessments in the 2014 Budget.

All penalties received prior to June 30, 2012 are detailed below, including the amount and date received.

**Allocation Method**

Penalty sanctions received have been allocated to the following statutory programs to reduce assessments: Reliability Standards; Compliance Operations and Organization Registration and Certification; Compliance Enforcement; Reliability Assessments and Performance Analysis; Training and Education; Situational Awareness; Events Analysis and Investigations; and the Critical Infrastructure Department. Penalty sanctions are allocated based upon the number of FTEs in the Program divided by the aggregate total FTEs in the Programs receiving the allocation.

**Table B-2**

| Penalty Sanctions Received On or Prior to June 30, 2012 | Date Received | Amount Received |
|---|---|---|
| | 7/17/2011 | $ 175,000 |
| | 9/9/2011 | 175,000 |
| | 9/14/2011 | 100,000 |
| | 12/7/2011 | 1,962,500 |
| **Total Penalties Received** | | $ 2,412,500 |

## Supplemental Funding

### Table B-3

| Outside Funding Breakdown By Program (Excluding Penalty Sanction) | Budget 2012 | Projection 2012 | Budget 2013 | Variance 2013 Budget v 2012 Budget |
|---|---|---|---|---|
| **Reliability Assessment and Performance Analysis** | | | | |
| **Total** | $ 250,000 | $ 125,000 | $ - | $ - |
| **Training and Education** | | | | |
| Testing Fees and Certificate Renewals | $ 1,340,000 | $ 1,340,000 | $ 1,277,500 | (62,500) |
| CEH Fees | 600,000 | 600,000 | 600,000 | - |
| Workshops | 120,000 | 175,225 | - | (120,000) |
| **Total** | $ 2,060,000 | $ 2,115,225 | $ 1,877,500 | $ (182,500) |
| **General and Administrative** | | | | |
| Interest Income | $ 20,000 | $ - | $ 20,000 | $ - |
| **Total** | $ 20,000 | $ - | $ 20,000 | $ - |
| **Total Outside Funding** | $ 2,330,000 | $ 2,240,225 | $ 1,897,500 | $ (182,500) |

## Personnel Expenses

**Table B-4**

| Personnel Expenses | Budget 2012 | Projection 2012 | Budget 2013 | Variance 2013 Budget v 2012 Budget | Variance % |
|---|---|---|---|---|---|
| **Total Salaries** | $ 24,800,833 | $ 23,491,962 | $ 24,472,982 | $ (327,851) | -1.3% |
| **Total Payroll Taxes** | 1,524,935 | 1,414,721 | 1,501,392 | (23,543) | -1.5% |
| **Total Benefits** | 3,190,308 | 2,467,328 | 2,815,344 | (374,964) | -11.8% |
| **Total Retirement** | 3,489,736 | 2,402,063 | 2,647,551 | (842,185) | -24.1% |
| **Total Personnel Costs** | $ 33,005,812 | $ 29,776,074 | $ 31,437,268 | $ (1,568,544) | -4.8% |
| **FTEs** | 176.75 | 174.74 | 186.25 | 9.50 | 5.4% |
| **Cost per FTE** | | | | | |
| Salaries | $ 140,316 | $ 134,440 | $ 131,399 | (8,917) | -6.4% |
| Payroll Taxes | 8,628 | 8,096 | 8,061 | (566) | -6.6% |
| Benefits | 18,050 | 14,120 | 15,116 | (2,934) | -16.3% |
| Retirement | 19,744 | 13,746 | 14,215 | (5,529) | -28.0% |
| **Total Cost per FTE** | **$ 186,737** | **$ 170,402** | **$ 168,791** | **$ (17,947)** | **-9.6%** |

## Consultants and Contracts

**Table B-5**

**NOTE: This table has been replaced by Exhibit B**

## Office Rent

### Table B-6

| Rent | Budget 2012 | Projection 2012 | Budget 2013 | Variance 2013 Budget v 2012 Budget | Variance % |
|---|---|---|---|---|---|
| Office Rent | $ 2,304,257 | $ 2,784,036 | $ 2,516,814 | $ 212,557 | 9.22% |
| Utilities | | | - | - | |
| Maintenance | | | - | - | |
| **Total Office Rent** | **$ 2,304,257** | **$ 2,784,036** | **$ 2,516,814** | **$ 212,557** | **9.22%** |

## Office Costs

### Table B-7

| Office Costs | Budget 2012 | Projection 2012 | Budget 2013 | Variance 2013 Budget v 2012 Budget | Variance % |
|---|---|---|---|---|---|
| Telephone | $ 441,280 | $ 664,900 | $ 527,000 | $ 85,720 | 19.43% |
| Telephone Answering Srv | 2,400 | 2,171 | - | (2,400) | -100.00% |
| Internet | 312,900 | 631,644 | 354,000 | 41,100 | 13.14% |
| Office Supplies | 170,600 | 149,498 | 172,500 | 1,900 | 1.11% |
| Computer Supplies and Maintenance | - | - | - | - | |
| Computers | 37,000 | - | 3,000 | (34,000) | -91.89% |
| Computer Supplies | 91,400 | 178,209 | 116,900 | 25,500 | 27.90% |
| Maintenance & Service Agreements | 1,168,400 | 955,465 | 1,404,265 | 235,865 | 20.19% |
| Software | 130,670 | 19,693 | 38,500 | (92,170) | -70.54% |
| Network Supplies | - | 896 | - | - | |
| Publications & Subscriptions | 50,500 | 76,906 | 73,000 | 22,500 | 44.55% |
| Dues | 33,250 | 40,806 | 42,750 | 9,500 | 28.57% |
| Postage | 24,200 | 17,862 | 20,100 | (4,100) | -16.94% |
| Express Shipping | 49,000 | 52,195 | 64,500 | 15,500 | 31.63% |
| Copying | 139,000 | 125,001 | 135,000 | (4,000) | -2.88% |
| Reports | 3,219 | - | 8,000 | 4,781 | 148.52% |
| Stationary/Forms | 15,000 | - | 15,000 | - | 0.00% |
| Equipment Repair/Service Contracts | 25,000 | 24,769 | 30,000 | 5,000 | 20.00% |
| Bank Charges | 15,000 | 14,404 | 25,000 | 10,000 | 66.67% |
| Taxes | 50,000 | 182 | 50,000 | - | 0.00% |
| Merchant Card Fees | 80,000 | 87,641 | 102,000 | 22,000 | 27.50% |
| **Total Office Costs** | **$ 2,838,819** | **$ 3,042,241** | **$ 3,181,515** | **$ 342,696** | **12.07%** |

## Professional Services

### Table B-8

| Professional Services | Budget 2012 | Projection 2012 | Budget 2013 | Variance 2013 Budget v 2012 Budget | Variance % |
|---|---|---|---|---|---|
| Independent Trustee Fees | $ 980,000 | $ 980,000 | $ 980,000 | $ - | 0.00% |
| Trustee Search Fee | 75,000 | 75,000 | - | (75,000) | -100.00% |
| Outside Legal | 700,000 | 1,316,290 | 900,000 | 200,000 | 28.57% |
| Lobbying Fees | 50,000 | 50,000 | 50,000 | - | 0.00% |
| Accounting & Auditing Fees | 125,000 | 125,000 | 242,278 | 117,278 | 93.82% |
| Insurance Commercial | 75,000 | 75,000 | 110,000 | 35,000 | 46.67% |
| **Total Services** | **$ 2,005,000** | **$ 2,621,290** | **$ 2,282,278** | **$ 277,278** | **13.83%** |

## Other Non-Operating Expenses

### Table B-9

| Other Non-Operating Expenses | Budget 2012 | Projection 2012 | Budget 2013 | Variance 2013 Budget v 2012 Budget | Variance % |
|---|---|---|---|---|---|
| Interest Expense | $ - | $ - | $ - | $ - | |
| Line of Credit Payment | | - | | - | |
| Office Relocation | - | 60,955 | - | - | |
| **Total Non-Operating Expenses** | **$ -** | **$ 60,955** | **$ -** | **$ -** | **100.00%** |

# Section C — Non-Statutory Activity

**NERC has no non-statutory activities.**

# Section D — Supplemental Financial Statements

**Statement of Financial Position**
**2011 Audited, 2012 Projection, and 2013 Budget**

**STATUTORY**

| | (Per Audit) 31-Dec-11 | Projected 31-Dec-12 | Budget 31-Dec-13 |
|---|---|---|---|
| **ASSETS** | | | |
| Cash - unrestricted | 16,603,649 | 17,582,974 | 17,332,975 |
| Cash - restricted | 2,412,500 | 2,412,500 | |
| Trade Accounts receivable, net of allowance for uncollectible accounts of $152,323 (2009) | 3,542,891 | 3,542,891 | 3,542,891 |
| Prepaid expenses and other current assets | 551,841 | 551,841 | 551,841 |
| Security deposit | 114,903 | 114,903 | 114,903 |
| Cash value of insurance policies | 282,098 | 282,098 | 282,098 |
| Property and equipment | 5,088,886 | 4,402,331 | 4,594,630 |
| Total Assets | **28,596,769** | **28,889,539** | **26,419,338** |
| **LIABILITIES AND NET ASSETS** | | | |
| Liabilities | | | |
| Accounts payable and accrued expenses | 4,751,337 | 4,393,509 | 4,514,624 |
| Deferred income | 2,644,176 | 2,644,176 | 2,644,176 |
| Regional assessments | 4,675,028 | 4,675,028 | 4,675,028 |
| Deferred compensation | 594,629 | 594,629 | 594,629 |
| Accrued retirement liabilities | 1,682,481 | 1,364,403 | 1,524,265 |
| Accrued incentive compensation | 2,911,359 | 3,587,266 | 3,306,289 |
| Total Liabilities | **17,259,011** | **17,259,011** | **17,259,011** |
| Net Assets - unrestricted | 8,925,258 | 9,218,027 | 9,160,326 |
| Net Assets -temporarily restricted | 2,412,500 | 2,412,500 | |
| Total Liabilities and Net Assets | **28,596,769** | **28,889,539** | **26,419,338** |

**Statement of Cash Flows**
**Unrestricted Fund**
**2011 Audited, 2012 Projection, and 2013 Budget**

**STATUTORY**

| | Audited 12/31/2011 | Projected 12/31/2012 | Projected 12/31/2013 |
|---|---|---|---|
| Cash Flows from Operating Activities | | | |
| Change in assets | 6,131,280 | 292,769 | (57,701) |
| Adjustments to reconcile changes in net assets to net cash provided by operating activities: | | | |
| Depreciation and amortization | 1,217,872 | 1,592,217 | 1,579,801 |
| Bad debt expense | | | |
| Increase (decrease) in cash attributable to changes in operating assets and liabilities: | | | |
| Accounts receivable | (652,100) | - | |
| Prepaid expenses and other assets | (15,320) | - | |
| Accounts payable and accrued expenses | 2,794,635 | (357,828) | 121,115 |
| Deferred rent | 715,382 | | |
| Loss on Disposal of Fixed Assets | 17,476 | | |
| Deferred income | (1,575,354) | | |
| Regional assessments collected in advance | (5,073,605) | | |
| Deferred compensation | (26,332) | | |
| Accrued bonus | | 675,906 | (280,977) |
| Accrued retirement liabilities | 207,568 | (318,078) | 159,862 |
| Net cash provided by operating activities | 3,741,502 | 1,884,986 | 1,522,100 |
| Cash Flows used in Investing Activities | | | |
| Purchases of property and equipment | (4,320,116) | (905,662) | (1,772,100) |
| Security deposits | (14,354) | 0 | |
| Cash value of insurance policies | (29,789) | | |
| Net cash used in investing activities | (4,364,259) | (905,662) | (1,772,100) |
| Net increase (decrease) in unrestricted cash | (622,757) | 979,324 | (250,000) |
| Unrestricted Cash, beginning of year | 17,226,407 | 16,603,650 | 17,582,974 |
| Unrestricted Cash, current period | 16,603,650 | 17,582,974 | 17,332,975 |

# Exhibit A — Common Assumptions

## Shared Business Plan and Budget Assumptions

NERC and the Regional Entities
2013-2015 Planning Period

Commencing in December 2011, NERC and the eight Regional Entities have been collaborating in the development of a common set of business planning goals, objectives and assumptions for the 2013-2015 planning period. This effort included the development of a mutually agreed upon Strategic Plan (http://www.nerc.com/filez/business_plan_2013.html).

As part of the implementation of the Strategic Plan, NERC and the Regional Entities developed a set of common assumptions that are now used to guide resource projections over the planning period for each entity and the ERO overall, recognizing there are often unique factors that drive differences in each organization's final determination of its resource needs and budget. The specific resource needs and budget of NERC and each Regional Entity will continue to be publicly posted for review and approved in open session by NERC's Finance and Audit Committee as part of the annual business plan and budget process.

It continues to be the objective of NERC and the Regional Entities to strive to identify and implement process and other improvements to increase the overall efficiency and effectiveness of the ERO, with due recognition and sensitivity to the cost of compliance by industry and the critical nature of industry support and participation to the success of the ERO regulatory model as contemplated by the Energy Policy Act of 2005. It is neither the goal nor objective of NERC and the Regional Entities to simply expand the scope of program areas or resources. Efforts have been made to focus on assumptions affecting resource requirements versus specific program area goals, objectives and actions. This document is an update to the initial draft of the common business plan and budget assumptions which were posted on NERC's website on February 21, 2012 and reflects consideration of the comments received on that draft, which are also posted on NERC's website.

### Legal and Operating Framework

NERC and the Regional Entities are expected to continue to work under the existing regulatory framework governing the establishment and enforcement of reliability standards for the bulk power system established by applicable governmental authorities in the United States and Canada, as well as the authorizations contained in FERC's order approving NERC as the ERO. No significant changes to this framework are assumed to occur over the planning period. However, the final determination of what constitutes the Bulk Electric System (BES) may affect the scope of ERO jurisdictional facilities. This ~~will~~is not expected to be known until 2013.

The terms of the existing delegation agreements between NERC and the Regional Entities are also assumed to continue to apply over the planning period. With respect to day to day routine operation of the ERO, the Regional Entities are expected to have the primary responsibility for

interactions with registered entities. NERC will provide oversight of the Regional Entities and otherwise ensure that its responsibilities as the ERO are fulfilled. Over the planning period, NERC and the Regional Entities are also expected to refine and revise procedures to eliminate duplication, increase operational efficiencies, enhance ERO-wide consistency, and achieve measureable reliability outcomes, consistent with their respective roles and responsibilities.

**Business Environment**

NERC and the Regional Entities will work collaboratively to identify additional ways to improve efficiency and leverage overall ERO resources. Industry concerns relative to the overall cost of compliance with ERO requirements will likely continue.

Cost pressures may affect stakeholder resources available to participate in NERC and Regional Entity activities. NERC and the Regional Entities business plans, budgets, and resource requirements will continue to be established based upon the assumption of continued industry participation in support of key program areas, including but not limited to standards development, event analysis and reliability assessments. Any significant change in the quality or availability of industry resources will likely affect ERO resource requirements.

General

External factors will continue to affect both resource needs and allocation. These factors will likely include, but not be limited to:

- FERC orders, directives, audits, and performance assessment
- The final definition of the BES, as well as the number of exception requests
- The rate of entity violations
- The assessment of the impact of new technologies
- Proposed and actual changes in applicable laws and regulations, including environmental and others

The activities of the transmission, generator and other forums are expected to compliment ERO activities and place downward pressure on the need to add incremental resources which might otherwise be required in the absence of these forums.

NERC and the Regional Entities expect gains in efficiency, year-upon-year, as programs and initiatives mature, experience is gained, standards are improved and internal process and performance improvements are achieved.

Key Assumptions by Program Area

**Reliability Standards Program**

1. While NERC standards development has historically been managed on a “projects” basis, experience has shown that increased project management discipline is necessary to satisfy standards development goals and priorities, including the assurance of a

requisite level of quality. Examples of efforts to increase project management discipline during the planning period include but are not necessarily limited to:

a. Specific timeframes for standards process milestones;

b. Increased industry resource dedication over shorter periods; and

c. Clear criteria for cancellation of projects that have not yielded timely results.

2. NERC will need to allocate additional resources to support improvements in the quality of standards development and guidance, including related training activities.
3. Review and modifications to the standards process may impact resources within the standards program area. Significant increases in standards processing may create additional resource needs to review and comment on proposed standards, support regulatory filings and oversee new standards as they become effective. However, any incremental resource needs are expected to be offset by improvements in the efficiency of the standards development process.
4. Implementing a cost effectiveness analysis or assessment of proposed standards is likely to impact resource requirements, but the extent of the impact cannot be fully assessed at this time.
5. The number of interpretation and guidance requests is expected to decrease over time, reflecting the impact of the results-based standards initiative and improved standards development process.
6. The number of projects contained in the Reliability Standards Development Plan is expected to increase over the planning period. However, the scope of these projects is generally expected to be narrower than would otherwise exist in the absence of the results-based standards initiative.
7. Activity associated with regional standards development is expected to decrease, together with staffing resources supporting this area.
8. Improvements in the quality of standards drafting and implementation should result in improvements in the efficiency and effectiveness of auditing and enforcement activities towards the end of the planning period.
9. NERC will increase the quality and effectiveness of regulatory filings. Efforts will include but not necessarily be limited to:

   i. Greater use of pre-filing meetings which will include opportunities for regional and stakeholder participation;

   ii. Greater dialogue with regulatory authorities regarding the form and requirements for regulatory filings, including reducing the requirement for exhibits by instead relying on publicly available documentation on NERC's website; and

   iii. Seeking engagement with regulatory authorities to obtain formal regulatory authority input during standards development.

**Compliance Monitoring and Enforcement and Organization Registration and Certification Program**

***Compliance and Enforcement***

1. NERC and Regional Entities will have sufficient staff, supervision, and technical specialists with adequate collective professional competence and other resources, as needed, to perform the compliance work and to meet expected time frames for completing the work.
2. Staffing resources required for compliance and enforcement activities at NERC, are expected to be flat during the planning period; if minor resource additions are required, they will be offset by operating efficiencies in other areas.
3. Staffing resources required for compliance and enforcement activities at the Regional Entities over the planning period will vary based on regional needs and circumstances, with any increases generally expected to be mitigated through operating efficiencies in other areas.
4. Resource implications associated with the Find, Fix and Track (FFT) process are unclear at this time given the nascent state of the program. However, efficiency gains are expected as the program matures.
5. Results of implementation of the FFT process over the planning period will lead to continued refinement, improvement and prioritization of risk based compliance monitoring efforts.
6. Prospective entity impact evaluations will be accomplished using existing resources. Entity impact evaluations were previously titled entity risk assessments but have been changed based on continuing work with industry to further refine this topic.
7. Changes in TFE processing, including equipment class-based exceptions, audit sampling, and elimination of much of the reporting and review burden, must be implemented to improve efficiency.
8. The future use of spots checks will increase as risk-based monitoring is rolled out, but is not expected to affect overall resource requirements.
9. Improvements in consistency among the Regional Entities may facilitate more efficient resource allocation within the compliance and enforcement areas at NERC, as well as potentially reduce compliance costs for some registered entities.
10. Improvements in audit guidance may increase ERO efficiency, support improvements to resource allocation and help mitigate overall compliance costs.
11. Improvements in consistency among Regional Entities, and registered entities is expected from an improved centralized compliance, registration, analysis and tracking system. A significant multiyear investment will be required to develop and implement the system.
12. As risk-based monitoring activities increase, strong consideration will be given to modifying the current three (3) and six (6) year audit cycles for registered entities.

Changes to the three year audit cycle requirement for certified functions will require a change to the Rules of Procedure. The rigor, scope, depth and recurrence of audits and spot checks will be driven by reliability risk and not a predetermined schedule. As standards are improved, the need for clarifying documents, such as Compliance Application Notices (CANs) or interpretations, should decrease. Until the standards have been improved, CAN and interpretation activity is anticipated to occur at current levels.

13. The number of non-CIP violations discovered in 2011 is expected to decrease as most registered entities have now been audited at least once and the standards and their application has matured. The number of CIP violations is not expected to decrease and may increase over the planning period until all entities have undergone a CIP audit and until a measure of stability in the standards is reached.
14. Integration of the assessment of registered entity internal controls programs as part of the compliance monitoring program will allow NERC and the Regional Entities to further prioritize risk-based compliance monitoring activities. Greater emphasis on internal controls provide positive incentives for industry to demonstrative effective management of compliance programs that are focused on reliability, as well as place downward pressure on compliance resource requirements for both industry, NERC and the Regional Entities.
15. Further auditing efficiencies can be achieved by continued refinement of auditing procedures focused on the purpose, intent and reliability risk associated with applicable standards as well as the assessment of evidence.

***Organization Registration and Certification***

1. Implementation of the BES definition may place additional resource demands in the Registration area but the significance cannot be fully assessed at this time. If a high number of BES exceptions are requested, the potential for a backlog situation in the first years of implementation is possible.

**Reliability Assessment and Performance Analysis Program**

1. Implementation of a BES exception process is expected to impact resources requirements in this program area, but the significance of the impact cannot be fully assessed at this time, as resource requirements will be driven by the number of exception requests received. It's also expected that there may be resource impacts at the Regional Entity level. More information regarding these potential impacts will be addressed in the first draft of the NERC and Regional Entities' Business Plans and Budgets.
2. Investments will be needed to develop and implement improved data collection and analysis systems and capabilities and should improve overall ERO resource allocation and efficiency in the long term.

3. Resource impacts associated with new technologies and environmental regulations are uncertain at this point.
4. Implementation of an outcome based approach to achieve measureable improvements in reliability will likely require allocation of resources to this program area, the significance of which from an overall budget perspective cannot be determined at this time.

**Training, Education, and Operator Certification Program**

1. Both NERC and the Regional Entities agree that there are opportunities for improvements in the coordination, content and manner of internal and external training programs.
2. While additional or different resources will be required for certain training initiatives, it is not clear at this time whether these needs will translate into a significant increase in NERC's or any of the Regional Entities' budgets. The general sense at this point is that improvements with minimal budgetary impact can be achieved through better coordination, planning and management of training programs. The possible exception is in the area of additional resources need to support CEA staff auditor training, as further discussed below.
3. Implementation of auditor credentialing may result in resource impacts due to time period required to obtain necessary credentials.

**Situation Awareness and Event Analysis Program**

- NERC will restructure this program area by merging the Situation Awareness function into the Event Analysis department and include the ES-ISAC within the CIP department for budgeting purposes. NERC will budget and manage Event Analysis separately from the Compliance and Enforcement functions. NERC will budget the ES-ISAC as part of its CIP department.
- NERC will propose amendments to the Rules of Procedure to reflect this reorganization.
- NERC will cease providing contracted funding support for GPA and the NASPI initiative at the end of 2013.
- NERC will cease funding the IDC at the conclusion of its existing contract in May 2013 and will provide billing services to the IDC Users Group ~~i~~on a transitional basis, subject to FERC approval.
- NERC will continue to review the appropriateness of continued funding of other reliability tools, with any proposed changes thereto subject to review and input from the Regional Entities, appropriate NERC committees and working groups, and other affected parties.
- SAFNR will provide additional situational awareness capabilities at both NERC and Regional Entity levels. Significant additional resource investments are not anticipated to

be necessary for the Regional Entities to utilize SAFNR. NERC will continue to budget and incur costs to operate and maintain SAFNR.

- The number of "system occurrences" are expected to increase based on recent trends. However, it is unclear whether this increase will lead to an increase in the number of "qualified system events" requiring more detailed analysis. [35]

**Critical Infrastructure Protection**

1. NERC will need to increase CIP resource support for auditor training and credentialing, as well as compliance enforcement activities. The increased support will likely be in retaining outside experts to train/credential NERC and Regional staff as opposed to increasing the size of NERC staff.
2. The ES-ISAC will be budgeted as part of the CIP department.
3. NERC will continue to conduct and budget grid security exercises.

**Information Technology**

1. Significant investments will be required over the planning period to develop and implement program area and enterprise wide applications to support business needs, including compliance, registration and tracking systems and other project, data management and analysis tools to provide greater cost efficiency and uniformity across the ERO. NERC and the Regional Entities have put in place a framework to define business requirements, establish priorities, and define and manage resource requirements associated with ERO IT investments over the planning period. NERC has also established a more rigorous and coordinated program for assessing its own internal IT needs. Further information regarding these frameworks, as well as preliminary projected resource requirements over the planning period, will be included in NERC's draft 2013 Business Plan and Budget.
2. Ongoing investments will be required to develop, implement and maintain enhancements to the NERC and Regional Entity websites.

**Finance and Administrative**

1. It's too early to predict any potential additional resource requirements associated with the implementation of the ERO Risk Management framework, however monies were budgeted for this activity in 2012 and expenditures and resource requirements will at least be at that level. Regional Entities do not anticipate increased resource requirements due to this effort.

[35] The phrase "system occurrences" means events submitted and tracked that do not meet the ERO event analysis process categorization criteria (Category 1-5), Occurrence also include copper theft, substation intrusions and other occurrences on the bulk electric system which may be reported. The phrase "qualified system events" means events affecting the Bulk Electric System which meet the ERO event analysis process categorization criteria (Category 1-5).

2. NERC and the Regional Entities will work cooperatively to reduce overall operating expenses, focusing on opportunities to further reduce and/or improve the efficiency of travel, meeting, conference call, software licensing and hardware purchases, and insurance costs. Efforts will be made to improve the transparency of information regarding these categories of costs as part of the annual business plan and budget process.
3. NERC and the Regional Entities will work to improve budgeting and forecasting capabilities, as well as variance reporting.
4. NERC and the Regional Entities will work cooperatively to establish a common set of principles regarding the determination of working capital and contingency reserve requirements. However, working capital requirements will continue to be established on an entity by entity basis, with the requirements clearly set forth in and subject to review and approval as part of the annual business plan and budget process at the Regional Entity and NERC level.

# Exhibit B — 2013 Contractor and Consultant Budget Detail

| Program | Consultants & Contracts | 2013 BUDGET | INC (DEC) OVER 2012 |
|---|---|---|---|
| | | | |
| | | | |
| **Reliability Standards** | Subject Matter Experts -Std Development | - | (15,000) |
| | SPIG Recommendations | 150,000 | 150,000 |
| | | | |
| | **Total Reliability Standards** | **150,000** | **135,000** |
| | | | - |
| **Compliance Operations** | in Finance) | | - |
| | Procedures, Practices, Tools and reports and reports (Budgeted in Finance) | | - |
| | | | |
| | **Total Compliance Operations** | **-** | **-** |
| | | | - |
| **Events Analysis & Investigation** | SME's - Event Analysis | 120,000 | - |
| | | | |
| | | | |
| | | **120,000** | **-** |
| | | | - |
| **Reliability Assessments, System Analysis, GADS, TADS, & DADS** | | | |
| RAPA | Automatic Reliability Reports (Reclass to Maintenance Agreements) | | (100,000) |
| | Reliability affects of GMD | 250,000 | 50,000 |
| | Benchmarking-Centralized data collection | 50,000 | (25,000) |
| | RADS Assessment Database | 100,000 | 25,000 |
| | Scenario Consultant | 70,000 | - |
| | Publishing Consultant | - | (5,000) |
| | Probabilistic Assessment | | (50,000) |
| | | | |
| | | **470,000** | **(105,000)** |
| | | | |
| System Analysis | Modeling Initiative | | (50,000) |
| | | | |
| | | **-** | **(50,000)** |
| | | | |
| GADS/TADS/DADS | GADS Programming Support | | (200,000) |
| | GADS Maintenance | 42,000 | 42,000 |
| | TADS Change management- Change Order #6 | 50,000 | - |
| | TADS Monthly maintenance | 30,000 | - |
| | Consulting | 30,000 | - |
| | DADS Programming Support | | |
| | DADS Monthly Maintenance | 43,000 | - |
| | Spare Equipment Database | 20,000 | - |
| | | | |
| | | **215,000** | **(158,000)** |
| | | | |
| | **Total Reliability Assessments and Performance Analysis** | **685,000** | **(313,000)** |

| Program | Consultants & Contracts | 2013 BUDGET | INC (DEC) OVER 2012 |
|---|---|---|---|
| | | | |
| **Situation Awareness** | Synchro Phasor (NASPI) | 700,000 | - |
| | | 110,000 | 110,000 |
| | | | |
| | | | |
| | Resource Adequacy (ACE Frequency) Tool | 80,000 | - |
| | Inadvertent Interchange (Srv. Agreement) | 35,000 | - |
| | AIE Monitoring (Srv. Agreement) | 35,000 | - |
| | Frequency Monitoring and Analysis Tool (FMA) | 45,000 | 45,000 |
| | Intelligent Alarms/DARA (Srv. Agreement) | 55,000 | - |
| | | | |
| | Secure Alerting System | 150,000 | 2,180 |
| | Secure Alerting System Help Desk | | (92,386) |
| | Secure Alert Change Management | 50,000 | - |
| | | | |
| | SAFNR - Phase II | 475,500 | 1,904 |
| | | | |
| | **Total Situation Awareness (excluding IDC and Frame Relay)** | **1,735,500** | **66,698** |
| | | | - |
| **Critical Infrastructure** | Cyber Risk Preparedness Assessment | 150,000 | 60,000 |
| | NIST/DOE Risk Guidelines | | (25,000) |
| | ESCC Support | 130,000 | - |
| | | | |
| | GridEx Support | 200,000 | 200,000 |
| | | | |
| | **ES-ISAC** | | |
| | ES-ISAC secure portal platform and annual hosting for | 90,000 | (160,000) |
| | Secure connection to US-CERT for bi-directional information sharing | 25,000 | (25,000) |
| | | | (250,000) |
| | Technical assistance to prepare and deliver Aurora Webinars | 15,000 | 15,000 |
| | Analytic capabilities | 60,000 | 60,000 |
| | Baseline Patterns and Analysis | 30,000 | 30,000 |
| | Integration Support Services for the the Wall of Knowledge | 55,000 | 55,000 |
| | ES-ISAC Members Conference | 30,000 | 30,000 |
| | **TOTAL ES-ISAC** | **305,000** | **(245,000)** |
| | | | |
| | | | |
| | **Total Critical Infrastructure Department** | **785,000** | **(10,000)** |

| Program | Consultants & Contracts | 2013 BUDGET | INC (DEC) OVER 2012 |
|---|---|---|---|
| | | | - |
| **Information Technology** | NERC Website Re-Design | 175,000 | 75,000 |
| | Security vulnerability testing of NERC websiste & network | 200,000 | - |
| | ERO Membership Service Agreement (Maintenance during re-write in 2013) | 24,000 | - |
| | NERC My Account Service Agreement (Maintenance during re-write in 2013) | 30,000 | - |
| | re-write in 2013) | 42,000 | - |
| | Infrastructure Integration and Design | 300,000 | (200,000) |
| | Meeting Manager (Not implemented due to move to SharePoint) | | (5,000) |
| | Compliance Database/IT Tools (CRATS) | 250,000 | (25,000) |
| | Compliance Database -(CITS/CUG) | | (50,000) |
| | Guidance Database Development-User Guided Content | 50,000 | (25,000) |
| | Standards Balloting-Upgrade | | (75,000) |
| | Standards Balloting Maintenance | 20,000 | (22,000) |
| | Contractor Project Manager | 100,000 | 100,000 |
| | Contractor Business Analyst | 100,000 | 100,000 |
| | Contract programming & development support | 100,000 | 100,000 |
| | Maintenance / Change Management - ERO Applications | 250,000 | 250,000 |
| | Outsourced Quality Assurance tester | 50,000 | 50,000 |
| | Data Warehouse design | 250,000 | 250,000 |
| | Common ERO technology platform - (SharePoint / Other) | 500,000 | 500,000 |
| | Studies & Assessments | 100,000 | 100,000 |
| | Disaster Recovery | 150,000 | 150,000 |
| | Iron Mountain Laptop Backup | 30,000 | 30,000 |
| | | **2,721,000** | **1,303,000** |
| **Human Resources** | Executive Training and Development | | - |
| | Strategic consulting on Risk-based, risk-avoidance compliance approach | 75,000 | - |
| | Collaboration and team-building leadership training | 15,000 | (10,000) |
| | **Instruction Technologists-Staff Development** | | (90,000) |
| | Online Training | 40,000 | 40,000 |
| | NERC Staff Project Management training | 12,000 | 12,000 |
| | NERC Staff Communications skills (presentations and writing) | 17,000 | 17,000 |
| | NERC Staff IT applications training | 17,000 | 17,000 |
| | NERC Staff developmental training | 20,000 | 20,000 |
| | Executive Recruiting (Budget $100k 2013 - 2015 in Personnel Expenses) | | (100,000) |
| | Compensation Consulting | 30,000 | 30,000 |
| | Employee, industry and Board Surveys, succession planning | 35,000 | 35,000 |
| | **HR Process Improvements** | | |
| | Single sign-on employee self-service | 20,000 | 20,000 |
| | Paperless HR | 7,500 | 7,500 |
| | | **288,500** | **(1,500)** |

| Program | Consultants & Contracts | 2013 BUDGET | INC (DEC) OVER 2012 |
|---|---|---|---|
| **Finance and Accounting** | Risk Management | 205,000 | (120,000) |
| | Assessment of CIP Auditing Practices and reports (Budgeted in Finance) | 60,000 | 60,000 |
| | Assessment of operations and planning standards Audits: Procedures, Practices, Tools and reports and reports (Budgeted in Finance) | 60,000 | 60,000 |
| | | **325,000** | **-** |
| | **TOTAL CONSULTANTS AND CONTRACTS (excl. IDC and Frame Relay)** | **7,809,834** | **1,441,834** |
| | | | - |
| **Situation Awareness** | **Contract - IDC** | | |
| | IDC Billing (46000) | | |
| | IDC Base Contract | 367,200 | (1,095,220) |
| | Generation-to-Load Reporting (CO-283) | 40,170 | 40,170 |
| | Incentive availability performance | 11,016 | 11,016 |
| | NERC Factor Viewer | 4,500 | (13,500) |
| | SDX Maintenance (2010 - using on CO-283) | 15,000 | (45,000) |
| | SDX 2010 Deferred Change Orders | | |
| | DF Support Services Agreement. | 12,500 | (37,500) |
| | Book of Flowgate Database | 7,200 | (21,600) |
| | Book of Flowgate Database-Maintenance (2010 - using on CO-283) | | |
| | **Contracts - IDC Total** | **457,586** | **(1,161,634)** |
| **Situation Awareness** | Frame Relay Billing (46100) | | |
| | Frame Relay-RC's | 300,094 | |
| | **Contracts - Total Frame Relay** | **300,094** | **-** |
| | **TOTAL CONSULTANTS, CONTRACTS, IDC AND FRAME RELAY** | **8,567,514** | **280,200** |

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## Exhibit C

## Proposed Form of Working Capital and Operating Reserve Policy

This policy governs the determination of the company's annual working capital and operating reserve requirements and the authorization of management to access these funds.

The company's working capital requirement shall be the amount necessary to satisfy projected annual cash flow and cash balance requirements. Annual cash flow and cash balance requirements shall be determined based on a review of (a) the company's projected cash flow needs over the applicable year and (b) cash balances required to satisfy any covenant under the terms of any loan, credit or other agreement to which the company is a party. To the extent that during the year the cash balances required to satisfy covenant obligations under the terms of any loan, credit or other agreement are reduced, such excess cash balance will be transferred to the company's operating reserve for unforeseen contingencies described below.

The company's operating reserves shall include (1) an amount necessary to satisfy known contingencies where the specific timing and amount is uncertain, (2) an amount available to be utilized for unforeseen contingency and (3) excess funds applicable to the Personnel Certification and Operator Training Program.

The amount of the company's working capital and operating reserves, by category, shall be separately identified and quantified each year in the business plan and budget submitted to and approved by the Board of Trustees. Transfers of working capital to operating reserves and transfers of operating reserve funds between categories shall require approval of the Board of Trustees, after review and recommendation by the Finance and Audit Committee.

The following guidelines shall apply to the determination of the company's operating reserves.

(1) Known Contingencies Where the Amount and Timing Are Uncertain
This category of operating reserves represents estimated funding reserves known contingencies where the timing and amount of funding to satisfy the contingency when it materializes is uncertain. An example would be the need for additional resources to address a requirement or process where regulatory or other governmental authorizations or directives are pending or anticipated but an order has not yet been issued so the amount of the impact and timing is uncertain, but management has nevertheless concluded that additional resources are likely to be required.

(2) Unforeseen Contingencies
This category of operating reserves represents a funding reserve for unknown contingencies which were not anticipated at the time of preparation and approval of the business plan and budget. Examples of unforeseen contingencies might include supplemental resources required to assist in the evaluation of significant unforeseen events affecting the bulk power system, such as the February Cold Weather Event and Southwest Outage or to address unforeseen regulatory directives.

(3) Excess Funds applicable to the Personnel Certification and Operator Training Program
In the event the company realizes higher levels of funding from operator certification and training above incurred expenses, this excess funding shall constitute a separate category of operating reserve and shall be used solely for operator training and certification needs, as determined by the company and the Personnel Certification Governance Committee. This is consistent with the intent of Section 604.4.10 of the Rules of Procedures.

**Guidelines and Authorities Applicable to Expenditures of Working Capital and Operating Reserves**

The following guidelines, limitations and authorities shall apply to expenditures of working capital and operating reserves.

1. The Chief Financial and Administrative Officer shall have the authority to draw on budgeted working capital reserves to the extent necessary to satisfy daily cash flow requirements. Any such draws of working capital reserves shall to the extent possible be promptly replenished from future excess cash flow.
2. For expenditures of operating reserves for budgeted known contingencies, the company's president and chief executive officer is authorized to expend such reserves up to the amount set forth in the company's budget.
3. For budgeted expenditures of excess funds associated with the Personnel Certification and Operator Training Program, the company's president and chief executive officer is authorized to expend such reserves up to the amount set forth in the company's budget.
4. For expenditure of operating reserves budgeted for unforeseen contingencies and for unbudgeted expenditures of excess funds associated with the Personnel Certification and Operator Training Program:
   i. The president and chief executive officer shall have authority to make expenditures up to $250,000;
   ii. For expenditures greater than $250,000 but less than $500,000 prior approval of the Finance and Audit Committee is required; and
   iii. For expenditures in excess of $500,000 approval of the Board of Trustees is required, after notice to and recommendation by the Finance and Audit Committee.
5. Any expenditure of funds in excess of the company's approved budget, inclusive of budgeted working capital and operating reserves, requires the prior approval of the Board of Trustees, after notice to and recommendation of the Finance and Audit Committee.

All expenditures of contingency funds are subject to other applicable company policies and procedures, including currently effective procurement policies and delegations of authority,

and 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 the company's website.

The procedures set forth in Section 1108 of the Rules of Procedure, including Board of Trustees and FERC approval, shall continue to apply in circumstances where the company requires funding between normal annual budget cycles in excess of amounts available through approved assessments, working capital and operating reserve resources.

**Guidelines and Authorities Required to Reallocate Budgeted Expenditures on an Intra-year Basis**

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.

**Addition of Unbudgeted FTE or Headcount Additions**

Any FTE or headcount additions, regardless of the source of and availability of funding, which are in excess of the total FTEs or total headcount, respectively, set forth in the company's approved business plan and budget for the applicable budget year shall require approval of the Board of Trustees, after review by the Corporate Governance and Human Resources Committee and the Finance and Audit Committee.

Proposed 2013 Working Capital and Operating Reserve Amounts

Working Capital- $700k

Based upon its 2013 cash flow projection and taking into account the historic manner in which NERC's assessments have been billed and paid, including the fact that WECC collects and pays its annual allocated share of the NERC assessments during the 1st quarter of the year, NERC does not anticipate needing access to working capital in 2013 to meet monthly cash flow needs. In the unlikely event NERC need experiences a temporary cash flow shortage it has the ability to either request authorization from the Finance and Audit Committee and Board of Trustees to temporarily access operating reserve funds or draw on its $4M line of credit so long as NERC is in compliance with the covenants under its bank credit agreement.

NERC's credit agreement currently requires NERC to maintain a minimum of $700k in net assets (total assets minus intangible assets minus total liabilities) and a minimum interest coverage ratio of 3 to 1.[36] While management expects that the company will be capable fo meeting this requirement without maintaining additional working capital reserves, management recommends that an amount equal to the minimum net assets required pursuant to the credit agreement be maintained as working capital in order to ensure that NERC's $4M line of credit remains available.

NERC has also posted letters of credit totaling approximately $134,146 in lieu of cash security deposits in connection with its offices leases. In the event these lines of credit get drawn on, NERC is required to reimburse the draws in full. Management does not recommend at this time that working capital be maintained as security for this reimbursement obligation.

Operating Reserves- $3.450M (Known Contingency Category-$1.350M + Unforeseen Contingency Category $1M + Personnel Certification and Operating Training Excess Revenues $1.75M)

Operating reserve amounts are divided into three categories: (1) known contingencies, (2) unknown contingencies and (3) excess revenues from the Personnel Certification and Operator Training Programs. Management's proposal with respect to the amount of 2013 reserves for each of these categories is set forth below.

(1) Known Contingencies where timing and amount uncertain[37] -$1.350M representing 50% of the maximum aggregate estimated cost of $2.7M for the following known contingencies:

[36] These covenants are currently under review by the lender and may be revised in the future to potentially increase the required minimum net assets covenant and eliminate the interest coverage covenant. In the event the minimum net assets covenant is increased, management proposes the amount of working capital would be also be increased on a dollar for dollar basis.

[37] To the extent that proposed reserves in this category become unnecessary due, for example, the terms and conditions of a FERC order, pursuant to the proposed Working Capital and Operating Reserve Policy management could make a request to the NERC Finance and Audit Committee and Board of Trustees to set aside funds for other

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a. SAFNR- vendor changes orders- $0-$50k
b. BES implementation- Outside contractor (subject matter experts) support- $0-$300k. Software application for submittal, processing and management of exclusion requests. $0-$300k
    i. NERC will be in a better position to develop a more informed forecast of this need after the FERC issues an order on the proposed definition of BES pending in FERC Docket RM12-6-000.
c. Implementation of NERC's revision to the Transmission Planning Reliability Standard, TPL-002-ob, Table 1, footnote b (FERC Docket No. RM11-18-000)- - Outside contractor (subject matter expert) support-$0-$250k
    i. NERC will be in a position to develop a more informed forecast of this need once the results of the NERC Rules of Procedure Section 1600 Data Request, regarding the use of Table 1, footnote b (*i.e.,* planned load shed in the event of a single contingency) have been received and reviewed.
d. Events Information database to enable NERC and the Regional Entities to uniquely identify eache vent, track documentation, critical dates and status and provide for secure transfers of information between NERC and the Regional Entities- $0-$300k
e. Automated system to collect reliability assessment data used for RAPA BPS assessments, reducing administrative burdens associated with collection of 500,000 data points annually - $0-$200k
f. Generation protection and controls modeling support to the extent DOE funding is no longer available- $0-$50k
g. FERC audit implementation- $0-$1.250M
    i. Compensation studies-$0-$200k
    ii. Accounting system upgrades- $0-$500k
    iii. Additional accounting staff- $0-$100k
    iv. Consultants- $0-$350k
    v. Additional CIP audit support is required in excess of 2013 budgeted internal CIP resources and external audit budget under Risk Management under Finance and Accounting- $25k per audit- $0-$100k

(2) Unforeseen Contingencies-$1M
(3) Personnel Certification and Operator Training Program- $1.75M[38]

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specific contingencies which became known after Board approval of the budget or request that all or a portion of the amount be transferred to the Unforeseen Contingencies category.

[38] Amount will be trued up in 2013 to reflect actual excess revenues at the end of 2012 based on 2012 audited financial statements, with the difference added to or subtracted from the Unforeseen Contingency operating reserve

a. In 2010 and 2011, the System Operator and Certification Program generated $1.4M in excess revenues over expenses

b. In 2012, the Program is projected to generate approximately $350k in excess revenues over expenses

Total Working Capital + Operating Reserves- $4.8M

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budget. Note that approximately $600k of these funds are proposed to be used for a multiyear upgrade of the System Operator and Certification database, as further described under the Training and Education Department section of the draft 2013 Business Plan and Budget and recommended in the Three Year Assessment.

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## Exhibit C

## Outline of Proposed IDC Billing Agency Structure

1. NERC and the IDC users (the "IDC Users Group") will enter into a agreement (the "Billing Services Agreement") pursuant to which NERC will provide the IDC Users Group with the services described below.
2. The IDC Users Group will be a party to an agreement with OATI with respect to the license, use, operation and maintenance of the IDC services presently provided to NERC by OATI (the "OATI IDC Agreement"), as well as any other contract needed to operate and maintain the IDC.
3. NERC will neither be a party to nor have any liabilities or obligations, financial or otherwise, under OATI IDC Agreement or with respect to any other agreement or undertaking involving the IDC.
4. NERC will act as a billing agent on behalf of the IDC Users Group and will allocate the IDC costs to and invoice Load Serving Entities ("LSEs") using the methodology which NERC presently uses to allocate IDC costs to LSEs. These costs will be included in the NERC's annual assessments to LSE's and other entities through the term of the Billing Services Agreement.
5. NERC and the IDC Users Group will develop a schedule for the preparation of the cost information and invoices to LSEs for IDC costs. The cost information shall include the OATI Contract Costs, the costs of the contract between of the IDC Users group and the Independent Electricity Operator with respect to the maintenance of IDC data bases and the book of flow gates, and NERC's administrative fee discussed further below. NERC will submit this cost information, together with a schedule of amounts to be billed to LSEs on behalf of the IDC Users Group, to the FERC, either as a separate filing or as part of its annual business plan and budget, and request FERC approval under Section 215 of the Federal Power Act.
6. Term- the agreement will have a limited duration, will be transitional in nature and at the end of the term the IDC Users Group will be responsible for putting in effect other arrangements to recover the costs of operating and maintaining the IDC without NERC's assistance. NERC has proposed that the term of the Agreement be through December 31, 2013.
7. The IDC Users Group will pay NERC a fixed fee (to be negotiated) for providing these services. This fee will be structured to include NERC's administrative costs in preparing the IDC cost allocation information and invoices, together with NERC's costs in obtaining FERC approval of the billing services arrangement and invoices. This fee will be included as part of the invoice NERC issues to the LSEs to recover the costs of the IDC on behalf of the IDC Users Group. During the term of the agreement, NERC will include this fee as revenue and a funding source under its annual business plan and budget submitted to the NERC Board of Trustees and FERC for approval.
8. The agreement will include indemnification and other provisions which are customary in similar commercial agreements.

9. The Billing Services Agreement and NERC's obligation to provide these services will be subject to the prior approval of FERC and NERC's obligations to provide the billing services shall also be subject to FERC's ongoing authorization for NERC to bill and collect the IDC costs from the LSEs under Section 215 of the Federal Power Act.

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May 24, 2012

On behalf of our member companies, the Edison Electric Institute (EEI) appreciates the opportunity to provide the following comments and observations on the proposed NERC 2013 budget and business plan.

**EEI has consistently raised the following themes over the past four years in its comments to NERC with regard to budgets and business plans:**

NERC should be applauded for standing up the Electric Reliability Organization and its organizational framework. The deadlines set by FERC for implementing Section 215 were extremely aggressive. The volume and pace of work was extremely challenging, nevertheless, deadlines were met and the work was performed. The speed of this work and the rapid growth required to support this work defined many of the challenges NERC faces today.

In light of this development history, EEI has consistently recommended that NERC focus its management attention and resources on the core program areas: standards development, and compliance and enforcement. Success in the core program areas is vital to NERC's long-term success. While seeking to engage a more diverse set of interesting activities, it is critically important to not distract limited NERC and Industry resources from the core mission. When the core program areas have matured, NERC will be ready to consider new areas of work within the scope of Section 215 and should have the management discipline upon which to build other sustainable program areas. Companies set limits on the scope of their work efforts to ensure that the commitments can be successfully produced and because there are practical limits for their expertise and resources, and NERC should do the same.

The compliance and enforcement program area has been significantly challenged from the outset. First, by an immediate and large backlog, second, by an apparent policy that all violations must be processed under an administratively bureaucratic one-size-fits-all enforcement tool, and third, by the development of varying approaches to compliance and enforcement by the regions. Companies strongly believe that the costs to NERC and the regions, and to companies, to process documentation and paperwork far outweigh any potential benefit to system reliability. Companies also are very frustrated by the ever-growing need to distract limited pools of highly specialized

expertise to the processing of unnecessary compliance-related paperwork. It is urgent that NERC return a realistic balance in the management of this program area.

The NERC Critical Infrastructure Program (CIP) needs strong management and a strategic focus. EEI and its member companies sometimes have been confused by what NERC is doing, the goals and objectives of various activities, when and where activities are taking place, and how to engage or support them. NERC CIP activities need to be coordinated with other industry work.

Specifically, NERC as the ES-ISAC has been an object of concern for four reasons. First, the ISAC structure is the product of a series of Presidential Directives that were issued prior to September 11, 2001, and which apply only in the United States. Second, most electricity delivery takes place at the local distribution level, which is not the expertise or focus of NERC, and is subject to the regulatory jurisdiction of the states.[1] Third, even considering the policy statement adopted by the NERC Board in February 2012, companies remain concerned over conducting sensitive or confidential discussions on any issue within the same organization that has legal responsibilities to conduct compliance and enforcement. Fourth, other industry sector ISAC activities have matured as self-funded standalone structures with strong relationships with the government. We believe our reasoning does not suggest a criticism of NERC performance but instead a strong sense that the ISAC function needs a high level discussion to ensure that the function is appropriately supported and positioned within the industry.

**Comments specific to the proposed 2013 NERC budget and business plan:**

We offer brief observations. In EEI comments on the 2012 budget we asked that NERC apply greater transparency and appreciate that in the 2013 budget NERC has applied many of our suggestions. In the proposed 2013 budget we find more details and greater specificity over what had been previously provided. For example, we note that efforts were made to provide greater clarity and more details in the area of contracts and consultants. We also appreciate efforts to better explain significant deviations from approved budgets and projected spending for the current year to add to greater budget transparency. A suggestion, that NERC consider adding information on the previous year's budget, including year-end totals as another piece of information that would help stakeholders assess ERO performance.

[1] Other areas such as business continuity in response to a pandemic require skills even further outside of NERC's expertise.

EEI is encouraged that NERC plans to include three-year projections in the second budget package planned for early June. All companies' strategic planning examines longer term spending plans in order to support management decisionmaking, support analyses of directional matters, and evaluate program success and we are pleased NERC will conform to this standard planning approach. We believe this is reflective of a maturing organization noting that NERC has grown to a level where management and the Board of Trustees, and stakeholders, have a clearer sense of longer term budget issues.

Another area where we believe additional work should be considered is in the development of measurable goals and priorities. With the exception of the Reliability Assessment and Performance Analysis group, the current list of priorities and goals will be very challenging to measure performance against stated goals for the year. EEI finds most of the work descriptions to be vaguely defined. EEI believes that more specificity would enable NERC to develop performance metrics which could be used to better communicate performance to stakeholders, the Board of Trustees, and to FERC. Stakeholders are particularly concerned that NERC has not sufficiently developed measurable goals and priorities for standards development in the context of staffing and technological upgrades. Although the Standards Committee along with NERC has developed goals and priorities for standards development, there seems to be a constraint based on NERC staffing levels and technology that holds back the processing of interpretations, standards and the related filings at FERC, as well as the quality of information provided on the NERC website. EEI suggests that NERC consider that over the next three to five years there are a large number of standards projects, interpretations and the like that will need support, in the form of short-term contactors or longer term permanent staff, as well as upgrades to its internet site. It may also be wise to consider the staffing and technology issues in light of the recent decision to revise the Standards Development Process, and whether the new process will require additional NERC resources and technology.

EEI continues to believe that the Situation Awareness program area needs much better strategic definition and clear boundaries. In NERC's 2012 budget it was stated that NERC would, as a "Key Deliverable," work with the Industry to develop a long term strategy for SAFNR. Presently this program lacks sufficient transparency for stakeholders to judge whether NERC has made noticeable efforts to develop or possibly refine the long term strategy for this program. We are concerned that there is no indication that the Industry has been engaged as promised. We further note that NERC plans to maintain the funding level for this program on par with 2012 levels with the only notable change being the termination of the IDC support contract which is a cost which is simply being shifted out of NERC to IDC users.

EEI recommends that NERC not provide resources for the human performance activity. While this appears to be small in terms of the overall budget, we believe this provides a clear example of NERC continuing to add various tasks and initiatives that potentially distract both NERC management and stakeholders from attending to the core program areas. As we have asked for several years, NERC should hold to a sustained emphasis on standards development, and compliance and enforcement, and avoid adding yet another new set of activities that will require time and attention of company personnel to monitor and manage.

Stakeholders have not seen a plan for the goals and objectives of this new activity, making measurements of success difficult to perform. It is also very difficult to understand what NERC plans to accomplish with one FTE, who we might imagine will conduct webinars and participate in various committee meetings. To the extent 'human performance' needs explicit attention, we recommend that a good start might be to consider including consideration of human error issues in existing training and certification programs.

NERC should not take this as a suggestion that consideration of 'human performance' – related activity is unimportant or should not be pursued. Human error is a significant challenge and a contributor to various system disturbances and events. To the extent explicit work is envisioned, we believe that this kind of activity is much better suited to the scope and mission of the North American Transmission Forum. In NERC decides to retain the activity, stakeholders deserve to participate in the development of a clearly stated plan with measurable goals and objectives.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

**Michael Walker**
**Senior Vice President and Chief Financial and Administrative Officer**

June 6, 2012

RE: Second Draft of the NERC 2013 Business Plan and Budget — Further Extension of Time Period for Stakeholder Comments

Dear Stakeholders,

In order to provide stakeholders with additional time to review and provide input on the second draft of NERC's 2013 Business Plan and Budget, we are further extending the time period for comments until Friday, July 6, 2012.

Questions or comments regarding NERC's draft 2013 Business Plan and Budget should be directed to me at Michael.walker@nerc.net.

As always we look forward to and appreciate your input.

Michael Walker
Senior Vice President and
Chief Financial and Administrative Officer

**3353 Peachtree Road NE**
**Suite 600, North Tower**
**Atlanta, GA 30326**
**404-446-2560 | www.nerc.com**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Michael Walker
Senior Vice President and Chief Financial and Administrative Officer

June 4, 2012

RE: Draft 2 of NERC 2013 Business Plan and Budget

Dear Stakeholders,

NERC has posted the second draft of its 2013 Business Plan and Budget [Clean Version], [Redline Version]. The following is a brief summary of the significant changes and additions from the prior draft:

- Refines and updates departmental information, including more specific detail regarding goals and objectives, including management focus on key responsibilities, as well as provides additional departmental operating cost information.
- Provides additional detail regarding NERC's Human Performance initiatives, SAFNR and the ES-ISAC.
- Incorporates significant additional detail regarding the IT operating and capital budgets.
- Updates the 2013 projection to reflect a combined operating and capital cost increase of $735k or 1.5 percent over 2012, which is slightly lower than the previous draft.
- Includes preliminary assessment calculations of an estimated 4.7 percent decrease for U.S entities, a 2.5 percent increase for Canadian entities and a 3.6 percent increase for entities in Mexico. These projections will be updated in the future to reflect the application of NERC policies regarding the allocation of certain compliance and enforcement costs.
- Provides projections for 2014 and 2015 which are relatively flat with 2013, with projected increases of .3 and 2.1 percent for 2014 and 2015, respectively.
- Includes an updated working capital and operating reserve policy and guidelines, together with details regarding 2013 proposed reserve amounts.
- Describes the proposed IDC billing services arrangement as part of the transition in NERC's direct involvement in incubating and funding the development of this important reliability tool to its present successful commercial state of use.

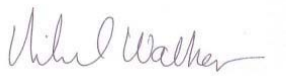
On May 30, 2012, NERC also filed the 2011 NERC and Regional Entities' true up filing with FERC. This filing provides a comparison of actual to budgeted costs for 2011 based on each Entity's year-end audited financial statements. This information, together with ongoing 2012 operating cost information, is utilized by both NERC and the Regional Entities in the formulation of their 2013 budgets and projections. A copy of this filing is posted on NERC's website at [2011 NERC True Up Filing].

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Questions or comments regarding the second draft of NERC's 2013 Business Plan and Budget should be directed to me at Michael.walker@nerc.net. We would like to have any written comments on or before Friday, June 29 which is an extension from the previous comment due date of June 25.

NERC's Finance and Audit Committee will conduct a conference call on July 19 to review the second draft of NERC's 2013 Business Plan and Budget and the final Regional Entities' 2013 Business Plans and Budgets, including any stakeholder comments.

As always we look forward to and appreciate your input.



Michael Walker
Senior Vice President and Chief Financial and Administrative Officer

**From:** Tina McClellan
**To:** Tina McClellan
**Subject:** NERC: POSTED: 2013 NERC Business Plan and Budget Comment Period Extension
**Date:** Thursday, June 07, 2012 1:28:58 AM

# POSTED

## NERC 2013 Business Plan and Budget Comment Period Extension

**To: Industry Stakeholders**

The following documents have been posted in relation to NERC's 2013 Business Plan and Budget:

- Comment Period Extension Memorandum from Michael Walker, Senior Vice President and Chief Financial and Administrative Officer
- EEI Comments to First Draft of NERC 2013 Business Plan and Budget

Questions and/or comments may be submitted to Michael Walker at michael.walker@nerc.net.

For more information or assistance, please contact Tina McClellan (via email) or 404-446-2564.

**3353 Peachtree Road NE**
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*Tina McClellan*
*Assistant Corporate Secretary*
*Manager of Corporate Support Services*
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**From:** Tina McClellan
**To:** Tina McClellan
**Subject:** NERC: POSTED: Second Draft of NERC"s 2013 Business Plan and Budget
**Date:** Monday, June 04, 2012 4:35:13 PM

# POSTED for Review and Comment

## NERC 2013 Business Plan and Budget — DRAFT 2

**To: Industry Stakeholders**

NERC has posted the following documents for review and/or comment:

- Cover Letter from Michael Walker, Senior Vice President and Chief Financial and Administrative Officer
- NERC 2013 Business Plan and Budget – DRAFT 2 (CLEAN)
- NERC 2013 Business Plan and Budget – DRAFT 2 (REDLINE)

Questions and/or comments may be submitted to Michael Walker at michael.walker@nerc.net.

For more information or assistance, please contact Tina McClellan (via email) or 404-446-2564.

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**From:** Philip A. Fedora
**To:** rcc
**Cc:** jtfc
**Subject:** FW: NERC - 2012 Emerging Issues Survey for Long Term Reliability Assessment
**Date:** Monday, July 02, 2012 7:16:47 AM
**Attachments:** 2012_EI_Background.docx
2012_EI_Issue_1.docx
2012_EI_Issue_2.docx
2012_EI_Issue_3.docx
2012_EI_Issue_4.docx
2012_EI_Issue_5.docx
2012_EI_Issue_6.docx
2012_EI_Issue_7.docx
2012_EI_Issue_8.docx
**Importance:** High

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To: RCC

NERC PC members are being asked to respond to the annual NERC "Emerging Issues" survey (see below).

Attached are word versions of the eight 2012 Emerging Issues for the LTRA that NERC and the RAS are surveying for your input.

Please return your completed word versions to me by Monday, July 23rd. I will consolidate the responses received and respond to the PC survey on behalf of NPCC on or before the July 27th deadline.

Thanks!

Phil

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**From:** Michelle Marx [mailto:Michelle.Marx@nerc.net]
**Sent:** Tuesday, June 26, 2012 1:21 PM
**To:** Michelle Marx
**Cc:** eric.rollison@nerc.net
**Subject:** NERC - 2012 Emerging Issues Survey for Long Term Reliability Assessment

# Announcement:

## 2012 Emerging Issues Survey for Long Term Reliability Assessment

**Survey Begins: June 26, 2012**
**Survey Ends: July 27, 2012**

**Survey Link**

Ladies and Gentlemen:

As part of the annual Long Term Reliability Assessment, the NERC staff along with industry input, identifies and analyzes the impact of key issues and trends that may affect reliability in the future, such as market practices, industry developments, potential technical challenges, technology implications, and policy changes.

NERC investigates these issues through structured technical committees and leveraged the expertise of the electric industry's broad knowledge base to identify areas for future work. The Reliability Assessment Subcommittee of the NERC Planning Committee has identified the following issues for ranking in 2012:

1. Environmental Regulations
2. Accommodating Variable Resources in System Operations
3. Gas-Electric Interdependency
4. Geomagnetic Disturbance Impacts to System Operations and Communications
5. Transmission Siting and Permitting
6. Potential Operational Risks Associated with Interaction of SPS/RAS
7. Global Supply Chains and Fuel Reliability
8. Assessment of Fault-Induced Delayed Voltage Recovery (FIDVR) Simulations

The survey asks respondents to determine both the *Probability of Occurrence* and *Impact to Reliability* in the 1 to 5 year time horizon and the 6 to 10 year time horizon.

If survey participants are unable to click the above link, the direct link to the survey is:
https://www.surveymonkey.com/s/6CGGWM5

Unlike previous years, the survey is available on-line and there are no word documents to complete.

All demographic information submitted with the survey will be considered confidential and results will not report any identifying information about participants

If you have any questions about the 2012 Emerging Issues survey, please contact:
**John Moura** at john.moura@nerc.net or **Eric Rollison** at eric.rollison@nerc.net

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**Suite 600, North Tower**
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2012 Long Term Reliability Assessment
Emerging Issues Survey – Background

**Background**
As part of the annual Long Term Reliability Assessment, NERC staff along with industry input, identifies and analyzes the impact of key issues and trends that may affect reliability in the future, such as market practices, industry developments, potential technical challenges, technology implications, and policy changes.

The Long-Term Reliability Assessment forms the basis for the NERC reference case. This reference case incorporates known policy and regulation changes expected to take effect throughout the ten-year timeframe assuming a variety of factors such as economic growth, weather patterns, and system equipment behavior.

A set of scenarios can then be developed from risk assessment of emerging reliability issues. These scenarios can then be compared to the reference case to measure and identify any significant changes to the bulk power system that may be required to maintain reliability.

For this reason, NERC investigates these issues through structured technical committees and leveraged the expertise of the electric industry's broad knowledge base to identify areas for future work.

The 2012 Emerging Issues are the following:
1. Environmental Regulations
2. Accommodating Variable Resources in System Operations
3. Gas-Electric Interdependency
4. Geomagnetic Disturbance Impacts to System Operations and Communications
5. Transmission Siting and Permitting
6. Potential Operational Risks Associated with Interaction of SPS/RAS
7. Global Supply Chains and Fuel Reliability
8. Assessment of Fault-Induced Delayed Voltage Recovery (FIDVR) Simulations

***Demographic Information***
**1. Demographic Information (will not be used in development of results).**

**Name**: Click here to enter text.
**Company:** Click here to enter text.
**Email Address:** Click here to enter text.

**2. Please identify which NERC Committee you represent:**

- Planning Committee
- Operating Committee
- Critical Infrastructure Protection Committee
- Member Representatives Committee
- NERC Stakeholder - No Affiliation to above Committees

**Emerging Issue 1: Environmental Regulations**

In the United States, several regulations are in the process of being proposed by the U.S. Environmental Protection Agency (EPA) that directly affects the electric industry. Depending on the outcome of any or all of these potential regulations, the results could accelerate the retirement of a significant number of fossil-fired power plants. EPA is currently developing rules that would mandate existing power suppliers to either retrofit environmental controls at existing generating plants or retire them. The most significant proposed EPA rules have been in development for over ten years and are currently undergoing court-ordered revisions that must be implemented within mandatory timeframes.

Emerging Issue #RAS-1: Environmental Regulations Background PDF

Definition of Adequate Level of Reliability

1. **Which Adequate Level of Reliability (ALR) characteristics would this emerging issue have an impact on (multiple selections below are allowed).**

☐ The System is controlled to stay within acceptable limits during normal conditions

☐ The System performs acceptably after credible Contingencies

☐ The System limits the impact and scope of instability and cascading outages when they occur

☐ The System's Facilities are protected from unacceptable damage by operating them within Facility Ratings

☐ The System's integrity can be restored promptly if it is lost

☐ The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components

2. **Does this Emerging Issue impact Resource Adequacy in the 10 year horizon?**

● Extremely High Impact to Reliability of bulk power system

● High Impact to Reliability of bulk power system

● Medium Impact to Reliability of bulk power system

● Low Impact to Reliability of bulk power system

● Extremely Low Impact to Reliability of bulk power system

● No Impact to Reliability of bulk power system

**3. Does this Emerging Issue impact Real-Time Operations in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**4. Does this Emerging Issue impact Long-Term Planning in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**5. What is the Probability of Occurrence of this issue during the 1 to 5 year time horizon (2013 through 2018)?**

- Very Rare (Once per hundred years or probability of 0.000001)
- More Rare (Once per ten years or probability of 0.00001)
- Rare (Once per year or probability of 0.0001)
- Less Likely (Once in forty days or probability of 0.001)
- Likely (Once in four days or probability of 0.01)
- Very likely (Once in ten hours or probability of 0.1)

**6. What is the Probability of Occurrence of this issue during the 6 to 10 year time horizon (2019 through 2023)?**

- Very Rare (Once per hundred years or probability of 0.000001)
- More Rare (Once per ten years or probability of 0.00001)
- Rare (Once per year or probability of 0.0001)
- Less Likely (Once in forty days or probability of 0.001)
- Likely (Once in four days or probability of 0.01)
- Very likely (Once in ten hours or probability of 0.1)

**7. What is the Impact to Reliability during the 1 to 5 year time horizon (2013 through 2018)?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**8. What is the Impact to Reliability during the 6 to 10 year time horizon (2019 through 2023)?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**Emerging Issue 2: Variable Resources in System Operations**

The expected significant increase in variable generation additions to the bulk power system will increase the amount of uncertainty that a system operator must factor into operating decisions. To manage this increased uncertainty, the system operator must have access to advanced variable generation forecasting techniques and have access to sufficient flexible resources to mitigate the added variability and uncertainty associated with the large scale integration of variable generation. In this respect, operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures and tools must be enhanced to assist operators in maintaining bulk power system reliability.

Emerging Issue #RAS-2: Accommodating Variable Resources in System Operations Background PDF

Definition of Adequate Level of Reliability

1. **Which Adequate Level of Reliability (ALR) characteristics would this emerging issue have an impact on (multiple selections below are allowed).**

- ☐ The System is controlled to stay within acceptable limits during normal conditions
- ☐ The System performs acceptably after credible Contingencies
- ☐ The System limits the impact and scope of instability and cascading outages when they occur
- ☐ The System's Facilities are protected from unacceptable damage by operating them within Facility Ratings
- ☐ The System's integrity can be restored promptly if it is lost
- ☐ The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components

2. **Does this Emerging Issue impact Resource Adequacy in the 10 year horizon?**

- ● Extremely High Impact to Reliability of bulk power system
- ● High Impact to Reliability of bulk power system
- ● Medium Impact to Reliability of bulk power system
- ● Low Impact to Reliability of bulk power system
- ● Extremely Low Impact to Reliability of bulk power system
- ● No Impact to Reliability of bulk power system

**3. Does this Emerging Issue impact Real-Time Operations in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**4. Does this Emerging Issue impact Long-Term Planning in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**5. What is the Probability of Occurrence of this issue during the 1 to 5 year time horizon (2013 through 2018)?**

- Very Rare (Once per hundred years or probability of 0.000001)
- More Rare (Once per ten years or probability of 0.00001)
- Rare (Once per year or probability of 0.0001)
- Less Likely (Once in forty days or probability of 0.001)
- Likely (Once in four days or probability of 0.01)
- Very likely (Once in ten hours or probability of 0.1)

**6. What is the Probability of Occurrence of this issue during the 6 to 10 year time horizon (2019 through 2023)?**

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- Rare (Once per year or probability of 0.0001)
- Less Likely (Once in forty days or probability of 0.001)
- Likely (Once in four days or probability of 0.01)
- Very likely (Once in ten hours or probability of 0.1)

**7. What is the Impact to Reliability during the 1 to 5 year time horizon (2013 through 2018)?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**8. What is the Impact to Reliability during the 6 to 10 year time horizon (2019 through 2023)?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**Emerging Issue 3: Gas-Electric Interdependency**

The majority of new North American generating capacity projected for the next ten years will rely on natural gas as its primary fuel. With a shift to unconventional gas production in North America, the potential to increase availability of supply makes gas-fired generation a premier choice for new generating capacity in the future, overtaking and replacing coal-fired capacity. However, increased dependence on natural gas for generating capacity can amplify the bulk power system's exposure to interruptions in natural gas fuel supply and delivery. Mitigating strategies, such as storage, firm fuel contracting, alternate pipelines, dual-fuel capability, access to multiple natural gas basins, nearby plants using other fuels, or additional transmission lines from other areas,can contribute to managing this risk.

Emerging Issue #RAS-3: Gas-Electric Interdependency Background PDF

Definition of Adequate Level of Reliability

1. **Which Adequate Level of Reliability (ALR) characteristics would this emerging issue have an impact on (multiple selections below are allowed).**

☐ The System is controlled to stay within acceptable limits during normal conditions

☐ The System performs acceptably after credible Contingencies

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☐ The System's Facilities are protected from unacceptable damage by operating them within Facility Ratings

☐ The System's integrity can be restored promptly if it is lost

☐ The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components

2. **Does this Emerging Issue impact Resource Adequacy in the 10 year horizon?**

● Extremely High Impact to Reliability of bulk power system

● High Impact to Reliability of bulk power system

● Medium Impact to Reliability of bulk power system

● Low Impact to Reliability of bulk power system

● Extremely Low Impact to Reliability of bulk power system

● No Impact to Reliability of bulk power system

**3. Does this Emerging Issue impact Real-Time Operations in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**4. Does this Emerging Issue impact Long-Term Planning in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**5. What is the Probability of Occurrence of this issue during the 1 to 5 year time horizon (2013 through 2018)?**

- Very Rare (Once per hundred years or probability of 0.000001)
- More Rare (Once per ten years or probability of 0.00001)
- Rare (Once per year or probability of 0.0001)
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- Likely (Once in four days or probability of 0.01)
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**6. What is the Probability of Occurrence of this issue during the 6 to 10 year time horizon (2019 through 2023)?**

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- More Rare (Once per ten years or probability of 0.00001)
- Rare (Once per year or probability of 0.0001)
- Less Likely (Once in forty days or probability of 0.001)
- Likely (Once in four days or probability of 0.01)
- Very likely (Once in ten hours or probability of 0.1)

**7. What is the Impact to Reliability during the 1 to 5 year time horizon (2013 through 2018)?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**8. What is the Impact to Reliability during the 6 to 10 year time horizon (2019 through 2023)?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**Emerging Issue 4: Geomagnetic Disturbance Impacts to System Operations and Communications**

The NERC GMDTF Interim Report forecast that the most likely result from a strong geomagnetic disturbance is voltage collapse. NERC also accepted that particularly large geomagnetically induced current (GIC) flows can result in transformer damage, and may ultimately result in the failure of some transformers. The industry is well-equipped to face a small number of transformer failures; however, due to the concerns about an extreme GMD event causing a larger than expected number of failures, it is important to carefully quantify the nature of the reliability risk.

Emerging Issue #RAS-4: Geomagnetic Disturbance Impacts to System Operations and Communications Background PDF

Definition of Adequate Level of Reliability

1. **Which Adequate Level of Reliability (ALR) characteristics would this emerging issue have an impact on (multiple selections below are allowed).**

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☐ The System performs acceptably after credible Contingencies

☐ The System limits the impact and scope of instability and cascading outages when they occur

☐ The System's Facilities are protected from unacceptable damage by operating them within Facility Ratings

☐ The System's integrity can be restored promptly if it is lost

☐ The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components

2. **Does this Emerging Issue impact Resource Adequacy in the 10 year horizon?**

● Extremely High Impact to Reliability of bulk power system

● High Impact to Reliability of bulk power system

● Medium Impact to Reliability of bulk power system

● Low Impact to Reliability of bulk power system

● Extremely Low Impact to Reliability of bulk power system

● No Impact to Reliability of bulk power system

**3. Does this Emerging Issue impact Real-Time Operations in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**4. Does this Emerging Issue impact Long-Term Planning in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**5. What is the Probability of Occurrence of this issue during the 1 to 5 year time horizon (2013 through 2018)?**

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- Very likely (Once in ten hours or probability of 0.1)

**6. What is the Probability of Occurrence of this issue during the 6 to 10 year time horizon (2019 through 2023)?**

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- Likely (Once in four days or probability of 0.01)
- Very likely (Once in ten hours or probability of 0.1)

**7. What is the Impact to Reliability during the 1 to 5 year time horizon (2013 through 2018)?**

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- Extremely Low Impact to Reliability of bulk power system
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**8. What is the Impact to Reliability during the 6 to 10 year time horizon (2019 through 2023)?**

- Extremely High Impact to Reliability of bulk power system
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- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**Emerging Issue 5: Transmission Siting and Permitting**

Siting difficulties have always been difficult for utilities. Siting of new bulk power transmission lines brings with it unique challenges due to the high visibility, their span through multiple states and/or provinces and, potentially, the amount of coordination/cooperation required among multiple regulating agencies and authorities. Lack of consistent and agreed upon cost allocation approaches (specific to transmission construction), coupled with public opposition due to land-use and property valuation concerns, have, at times, resulted in long delays in transmission construction. When construction is delayed, special operating procedures to maintain bulk power system reliability may be needed. For example, it took the American Electric Power Company fourteen years to obtain siting approval for a 90-mile 765 kV transmission project, while it required only two to construct it.

Emerging Issue #RAS-5: Transmission Siting and Permitting Background PDF

Definition of Adequate Level of Reliability

1. **Which Adequate Level of Reliability (ALR) characteristics would this emerging issue have an impact on (multiple selections below are allowed).**

- ☐ The System is controlled to stay within acceptable limits during normal conditions
- ☐ The System performs acceptably after credible Contingencies
- ☐ The System limits the impact and scope of instability and cascading outages when they occur
- ☐ The System's Facilities are protected from unacceptable damage by operating them within Facility Ratings
- ☐ The System's integrity can be restored promptly if it is lost
- ☐ The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components

2. **Does this Emerging Issue impact Resource Adequacy in the 10 year horizon?**

- ● Extremely High Impact to Reliability of bulk power system
- ● High Impact to Reliability of bulk power system
- ● Medium Impact to Reliability of bulk power system
- ● Low Impact to Reliability of bulk power system
- ● Extremely Low Impact to Reliability of bulk power system
- ● No Impact to Reliability of bulk power system

**3. Does this Emerging Issue impact Real-Time Operations in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**4. Does this Emerging Issue impact Long-Term Planning in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**5. What is the Probability of Occurrence of this issue during the 1 to 5 year time horizon (2013 through 2018)?**

- Very Rare (Once per hundred years or probability of 0.000001)
- More Rare (Once per ten years or probability of 0.00001)
- Rare (Once per year or probability of 0.0001)
- Less Likely (Once in forty days or probability of 0.001)
- Likely (Once in four days or probability of 0.01)
- Very likely (Once in ten hours or probability of 0.1)

**6. What is the Probability of Occurrence of this issue during the 6 to 10 year time horizon (2019 through 2023)?**

- Very Rare (Once per hundred years or probability of 0.000001)
- More Rare (Once per ten years or probability of 0.00001)
- Rare (Once per year or probability of 0.0001)
- Less Likely (Once in forty days or probability of 0.001)
- Likely (Once in four days or probability of 0.01)
- Very likely (Once in ten hours or probability of 0.1)

**7. What is the Impact to Reliability during the 1 to 5 year time horizon (2013 through 2018)?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**8. What is the Impact to Reliability during the 6 to 10 year time horizon (2019 through 2023)?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**Emerging Issue 6: Potential Operational Risks Associated with Interaction of SPS/RAS**
Increasingly, Special Protection Systems (SPS) are being installed in lieu of transmission facilities. While an SPS is a less costly alternative to new transmission facilities, and faster to install, there are instances where an SPS has failed to operate and in other instances where activating an SPS has resulted in additional unforeseen operational issues with negative reliability consequences. The deployment of an SPS often results in adding operational complexity to the grid operators. The lack of a modeling guide for planning SPS may have contributed to incomplete evaluation of the operational impacts of an SPS on the reliability of the power system.

Emerging Issue #RAS-6: Potential Operational Risks Associated with Interaction of SPS/RAS Background PDF

Definition of Adequate Level of Reliability

1. **Which Adequate Level of Reliability (ALR) characteristics would this emerging issue have an impact on (multiple selections below are allowed).**

☐ The System is controlled to stay within acceptable limits during normal conditions

☐ The System performs acceptably after credible Contingencies

☐ The System limits the impact and scope of instability and cascading outages when they occur

☐ The System's Facilities are protected from unacceptable damage by operating them within Facility Ratings

☐ The System's integrity can be restored promptly if it is lost

☐ The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components

2. **Does this Emerging Issue impact Resource Adequacy in the 10 year horizon?**

● Extremely High Impact to Reliability of bulk power system

● High Impact to Reliability of bulk power system

● Medium Impact to Reliability of bulk power system

● Low Impact to Reliability of bulk power system

● Extremely Low Impact to Reliability of bulk power system

● No Impact to Reliability of bulk power system

**3. Does this Emerging Issue impact Real-Time Operations in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**4. Does this Emerging Issue impact Long-Term Planning in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**5. What is the Probability of Occurrence of this issue during the 1 to 5 year time horizon (2013 through 2018)?**

- Very Rare (Once per hundred years or probability of 0.000001)
- More Rare (Once per ten years or probability of 0.00001)
- Rare (Once per year or probability of 0.0001)
- Less Likely (Once in forty days or probability of 0.001)
- Likely (Once in four days or probability of 0.01)
- Very likely (Once in ten hours or probability of 0.1)

**6. What is the Probability of Occurrence of this issue during the 6 to 10 year time horizon (2019 through 2023)?**

- Very Rare (Once per hundred years or probability of 0.000001)
- More Rare (Once per ten years or probability of 0.00001)
- Rare (Once per year or probability of 0.0001)
- Less Likely (Once in forty days or probability of 0.001)
- Likely (Once in four days or probability of 0.01)
- Very likely (Once in ten hours or probability of 0.1)

**7. What is the Impact to Reliability during the 1 to 5 year time horizon (2013 through 2018)?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**8. What is the Impact to Reliability during the 6 to 10 year time horizon (2019 through 2023)?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**Emerging Issue 7: Global Supply Chains and Fuel Reliability**

Supply chains are used in almost every industry to coordinate sourced resources from supplier to customer. Supply chains are systematic, incorporating a series of organizations, people, technology, activities, and information. Risk management theory tells us that supply chain disruptions are a function of the vulnerabilities associated with a given chain. Furthermore, vulnerabilities are a function of chain length and weakness—the more "chains" there are in the supply chain, the greater the likelihood there may be for a disruption; consequently, the weaker the "chains" are, the greater the likelihood there may be for a disruption.

Emerging Issue #RAS-7: Global Supply Chains and Fuel Reliability Background PDF

Definition of Adequate Level of Reliability

1. **Which Adequate Level of Reliability (ALR) characteristics would this emerging issue have an impact on (multiple selections below are allowed).**

☐ The System is controlled to stay within acceptable limits during normal conditions

☐ The System performs acceptably after credible Contingencies

☐ The System limits the impact and scope of instability and cascading outages when they occur

☐ The System's Facilities are protected from unacceptable damage by operating them within Facility Ratings

☐ The System's integrity can be restored promptly if it is lost

☐ The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components

2. **Does this Emerging Issue impact Resource Adequacy in the 10 year horizon?**

● Extremely High Impact to Reliability of bulk power system

● High Impact to Reliability of bulk power system

● Medium Impact to Reliability of bulk power system

● Low Impact to Reliability of bulk power system

● Extremely Low Impact to Reliability of bulk power system

● No Impact to Reliability of bulk power system

**3. Does this Emerging Issue impact Real-Time Operations in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**4. Does this Emerging Issue impact Long-Term Planning in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**5. What is the Probability of Occurrence of this issue during the 1 to 5 year time horizon (2013 through 2018)?**

- Very Rare (Once per hundred years or probability of 0.000001)
- More Rare (Once per ten years or probability of 0.00001)
- Rare (Once per year or probability of 0.0001)
- Less Likely (Once in forty days or probability of 0.001)
- Likely (Once in four days or probability of 0.01)
- Very likely (Once in ten hours or probability of 0.1)

**6. What is the Probability of Occurrence of this issue during the 6 to 10 year time horizon (2019 through 2023)?**

- Very Rare (Once per hundred years or probability of 0.000001)
- More Rare (Once per ten years or probability of 0.00001)
- Rare (Once per year or probability of 0.0001)
- Less Likely (Once in forty days or probability of 0.001)
- Likely (Once in four days or probability of 0.01)
- Very likely (Once in ten hours or probability of 0.1)

**7. What is the Impact to Reliability during the 1 to 5 year time horizon (2013 through 2018)?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**8. What is the Impact to Reliability during the 6 to 10 year time horizon (2019 through 2023)?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**Emerging Issue 8: Assessment of Fault-Induced Delayed Voltage Recovery (FIDVR) Simulations**
Fault-Induced Delayed Voltage Recovery (FIDVR) events are characterized by a depressed voltage for 5 to 30 seconds following a fault. These events are of concern because they show a temporary loss of voltage control in an area, and they pose a risk of cascading to a larger area, especially if another unexpected event occurs while the voltage is depressed. These events have been studied and are believed to be initiated by the stall of low-inertia induction motors during the fault. Motors at risk of stalling include compressor-driving loads such as air conditioners. The subject of FIDVR events, their causes and solutions is covered in a NERC white paper on this topic

Emerging Issue #RAS-8: Assessment of Fault-Induced Delayed Voltage Recovery (FIDVR) Simulations Background PDF

Definition of Adequate Level of Reliability

1. **Which Adequate Level of Reliability (ALR) characteristics would this emerging issue have an impact on (multiple selections below are allowed).**

☐ The System is controlled to stay within acceptable limits during normal conditions

☐ The System performs acceptably after credible Contingencies

☐ The System limits the impact and scope of instability and cascading outages when they occur

☐ The System's Facilities are protected from unacceptable damage by operating them within Facility Ratings

☐ The System's integrity can be restored promptly if it is lost

☐ The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components

2. **Does this Emerging Issue impact Resource Adequacy in the 10 year horizon?**

● Extremely High Impact to Reliability of bulk power system

● High Impact to Reliability of bulk power system

● Medium Impact to Reliability of bulk power system

● Low Impact to Reliability of bulk power system

● Extremely Low Impact to Reliability of bulk power system

● No Impact to Reliability of bulk power system

**3. Does this Emerging Issue impact Real-Time Operations in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**4. Does this Emerging Issue impact Long-Term Planning in the 10 year horizon?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**5. What is the Probability of Occurrence of this issue during the 1 to 5 year time horizon (2013 through 2018)?**

- Very Rare (Once per hundred years or probability of 0.000001)
- More Rare (Once per ten years or probability of 0.00001)
- Rare (Once per year or probability of 0.0001)
- Less Likely (Once in forty days or probability of 0.001)
- Likely (Once in four days or probability of 0.01)
- Very likely (Once in ten hours or probability of 0.1)

**6. What is the Probability of Occurrence of this issue during the 6 to 10 year time horizon (2019 through 2023)?**

- Very Rare (Once per hundred years or probability of 0.000001)
- More Rare (Once per ten years or probability of 0.00001)
- Rare (Once per year or probability of 0.0001)
- Less Likely (Once in forty days or probability of 0.001)
- Likely (Once in four days or probability of 0.01)
- Very likely (Once in ten hours or probability of 0.1)

**7. What is the Impact to Reliability during the 1 to 5 year time horizon (2013 through 2018)?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

**8. What is the Impact to Reliability during the 6 to 10 year time horizon (2019 through 2023)?**

- Extremely High Impact to Reliability of bulk power system
- High Impact to Reliability of bulk power system
- Medium Impact to Reliability of bulk power system
- Low Impact to Reliability of bulk power system
- Extremely Low Impact to Reliability of bulk power system
- No Impact to Reliability of bulk power system

## Emerging Issue #RAS-1: *Environmental Regulations*

| Emerging Issue | Item | Specifics |
|---|---|---|
| Horizon | **Number of years** | Within 2 to 10 Years |
| Status | **Emerging or Standing** | Standing |
| | **Technical Group** | Reliability Assessment Subcommittee (RAS) |
| Background | **Description** | In the United States, several regulations are in the process of being proposed by the U.S. Environmental Protection Agency (EPA) that directly affects the electric industry. Depending on the outcome of any or all of these potential regulations, the results could accelerate the retirement of a significant number of fossil-fired power plants. EPA is currently developing rules that would mandate existing power suppliers to either retrofit environmental controls at existing generating plants or retire them. The most significant proposed EPA rules have been in development for over ten years and are currently undergoing court-ordered revisions that must be implemented within mandatory timeframes.<br><br>This emerging issue section is will be a follow-on/updated assessment of the 2010 NERC Special Reliability Assessment and the 2011 Long-Term Reliability Assessment's update section. |
| | **What changes during the 10-year horizon?** | • Potential loss of significant amounts of generation<br>• Unit outages for maintenance due to retrofits<br>• Acceleration of new unit construction |
| | **What is the impact to regional reliability?** | • A significant amount of generation retirements and de-rates associated with environmental controls may severely impact reserve margins if replacement resources cannot be built or acquired by proposed deadlines.<br>• Potential loss of a significant amount of generation, either through retirements or de-rates associated with environmental controls equipment, during a short time frame (2014-2015)<br>• Unit outages for maintenance due to retrofits<br>  o Capability to retrofit existing plants to meet required emission targets<br>  o Ability for industry to coordinate the necessary outages in order to perform the retrofit<br>• Load pocket areas (i.e., major metropolitan areas) may be impacted by the loss of "critical" bulk power resources.<br>• Off-peak vulnerabilities when units are out of service for maintenance |

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|---|---|---|
| Assessment Factors | **Resource Adequacy Considerations** [Yes/No]? | Yes. Early retirement of multiple units in the short-run can stress the bulk power system if plans are not in place to add resources. This can affect both short- and long-term planning strategies and reduce Planning Reserve Margins. Sufficient Planning Reserve Margins must be maintained to provide reliable electric service. With fewer resources, flexibility is reduced and the risk of a capacity shortage may increase, unless additional resources are available. Where Planning Reserve Margins fall below targets or requirements, resources in a specific area may not be sufficient to meet future demands. |
| | **Transmission Adequacy Considerations** [Yes/No]? | Yes. As replacement generation is constructed, new transmission may be needed to interconnect new generation. Additionally, existing generation that may not be deliverable due to transmission limitations. Enhancements may be needed to the transmission system in order to support firm and reliable transmission service to support potentially new generation dispatch patterns. Transmission system enhancements and reconfiguration may be necessary in some areas, which create additional timing issues as new transmission facilities take relatively longer to construct than generation. Second tier effects include impacts to system stability, short-circuit, and deliverability. |
| | **Resource Siting Impacts** [Yes/No]? | Yes. Additional generation siting may be necessary to support the construction of new replacement generation. In some cases, existing sites will be used for replacement generation—for others, new sites will have to be developed. Each situation will have unique characteristics that determine how long the permitting process may actually last. This is of particular importance to the resource assessment due to the constricted compliance timelines associated with the potential rules. |
| | **Operations Impacts** [Yes/No]? | Yes. Along with other drivers, potential environmental regulations can change the overall fuel-mix, ultimately changing the inherent operating characteristics of a given resource portfolio. For example, with less coal-fired capacity, more gas-fired generation may need to provide base-load services. As a result, the interdependency of gas and electric supply, transport, and delivery must be further assessed to ensure reliability is not degraded. |
| | **Remaining Uncertainties** | • EPA waiver and exceptions used to keep generators online to maintain reliability<br>• Finalization of coal combustion residual and cooling water rules (mid-2012)<br>• Retirement announcements<br>• Transmission retrofits to accommodate new resources |

## Emerging Issue #RAS-2: *Accommodating Variable Resources in System Operations*

| Emerging Issue | Item | Specifics |
|---|---|---|
| Horizon | **Number of years** | Current and On-Going |
| Status | **Emerging or Standing** | Standing |
| | **Technical Group** | Integration of Variable Generation Task Force (IVGTF) |
| Background | **Description** | The expected significant increase in variable generation additions to the bulk power system will increase the amount of uncertainty that a system operator must factor into operating decisions. To manage this increased uncertainty, the system operator must have access to advanced variable generation forecasting techniques and have access to sufficient flexible resources to mitigate the added variability and uncertainty associated with the large scale integration of variable generation. In this respect, operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures and tools must be enhanced to assist operators in maintaining bulk power system reliability.<br><br>This emerging issue will include the on-going work of the Integration of Variable Generation Task Force, as well as recent reports on bulk power system operations.<br><br>• **Operating Practices, Procedures, and Tools**<br>• **Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation**<br>• **Variable Generation Power Forecasting for Operations** |
| | **What changes during the 10-year horizon?** | • Operational procedures<br>• Operating reserve requirements<br>• Dispatching methods<br>• Forecasting<br>• Flexibility needs |
| | **What is the impact to regional reliability?** | Improved operating practices, procedures and tools are critical to integrate variable generation into the power system, as well as improve the control performance and reliability characteristics of the power system. System resources supporting reliability, such as flexible generation and responsive load, are finite. Operating practices, procedures, and tools that maximize the effective use of limited responsive resources improve reliability and facilitate variable generation integration. |
| Assessment Factors | **Resource Adequacy Considerations** [Yes/No]? | Yes. Impacts to operating reserve margins and ancillary service requirements may affect short-term operational planning. Considerations for start-up times of fossil fueled resources will have to be included in operational planning for the variable resources. Impacts to long-term planning may be affected as well. |

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| | **Transmission Adequacy Considerations** [Yes/No]? | Yes. Within a balancing area, as the level of variable generation increases, the variability individually or when coupled with extreme events, such as system-wide high-rate ramping (up or down), may not be manageable with the existing conventional generation resources within the balancing area alone. If there is sufficient bulk power transmission, this situation may be managed by obtaining ancillary services and flexible resources from a larger generation base, such as through participation in wider-area balancing management or balancing area consolidation. Transmission planning and operations techniques, including economic inter-area planning methods, should be used for inter-area transmission development to provide access to and sharing of flexible resources.<br><br>Therefore, the composite capacity value of variable generation resources significantly improves when inter-area transmission additions enable variable generators across much wider geographic areas to interact with one another, hence improving overall system operational reliability. |
| | **Resource Siting Impacts** [Yes/No]? | Yes. Even if equivalent capacity of the new resources is placed in the same location on the system, there are still potential impacts due to the change in performance characteristics. |
| | **Operations Impacts** [Yes/No]? | Yes. An increase in variable generation resources may require changes to the dispatch as well as the types and amounts of operating reserves to compensate for the variability and uncertainty of the new resources. Additional sophistication is needed in EMS tools to incorporate weather and wind forecasts as well as locational dispatch for system stability to compensate for the different performance characteristics of the new resources. As more variable resources are added to the system before necessary changes can be made, challenges for system operators can be created.<br><br>There are significant differences in the actual scope and implementation of individual operator tools, which can be mainly attributed to the differences in the systems and associated markets for which the tools were developed. Some of the tools are intended to provide comprehensive information about existing system operating conditions and expected short-term changes, so that the operator can decide the most appropriate control action (operator training). These operator tools include additional visualization displays and calculation of system performance metrics for determining what measures should be undertaken to mitigate possible adverse effects. |
| | **Remaining Uncertainties** | • Availability of appropriate ancillary services to accommodate steep ramps from variable generation<br>• Real-time flexibility is unknown |

## Emerging Issue #RAS-3: *Gas-Electric Interdependency*

| Emerging Issue | Item | Specifics |
|---|---|---|
| Horizon | **Number of years** | Current and On-Going |
| Status | **Emerging or Standing** | Standing |
| | **Technical Group** | Reliability Assessment Subcommittee (RAS) |
| Background | **Description** | The majority of new North American generating capacity projected for the next ten years will rely on natural gas as its primary fuel. With a shift to unconventional gas production in North America, the potential to increase availability of supply makes gas-fired generation a premier choice for new generating capacity in the future, overtaking and replacing coal-fired capacity. However, increased dependence on natural gas for generating capacity can amplify the bulk power system's exposure to interruptions in natural gas fuel supply and delivery. Mitigating strategies, such as storage, firm fuel contracting, alternate pipelines, dual-fuel capability, access to multiple natural gas basins, nearby plants using other fuels, or additional transmission lines from other areas, can contribute to managing this risk.<br><br>In addition, going forward the electric sector will be responsible for most of the growth in natural gas demand. The combination of this growth in gas demand within the electric sector and its changing status among the gas consuming sectors has increased significantly the interdependences of the two industries, and caused many within both industries to focus more sharply on the interface between the two industries. A key element of this focus on the interface between the two industries is the need for increased coordination between the two industries, particularly at a regional level. |
| | **What changes during the 10-year horizon?** | Over the next ten years, a significant amount of gas-fired generation is projected—45 GW of Planned and an additional 48 GW of Conceptual capacity. |
| | **What is the impact to regional reliability?** | • Increased dependence on natural gas<br>• Just-in-time fuel source<br>• Contracting practices resulting in insufficient supplies for electric generators<br>• Large, common-mode failure on pipeline resulting in multiple unit outages<br>• Insufficient communication and coordination between the two industries could result in real-time and emergency challenges, as well as lack of integrated long-term planning. |

| | | |
|---|---|---|
| Assessment Factors | **Resource Adequacy Considerations** [Yes/No]? | Yes. Real-time availability of gas-fired generation could be hampered by insufficient gas-supplies stemming from production (e.g., well-head freeze offs), contracting practices (e.g., non-firm, interruptible service), and uncoordinated response to pipeline system conditions (e.g., pipeline fractures, pressure limits). |
| | **Transmission Adequacy Considerations** [Yes/No]? | Yes. Transmission must be considered as new gas-fired generation comes online. |
| | **Resource Siting Impacts** [Yes/No]? | Yes. Siting new gas plants at existing locations (coal brown-field sites for example) may be difficult due to pipeline availability/capacity in the area. The current layout of the gas pipeline network and the transmission network would make it difficult (economically) to site generation without considering the limitations of both. This is especially true if the new gas plant is not purchasing a long-term firm contract for gas delivery and transportation. |
| | **Operations Impacts** [Yes/No]? | Yes. Real-time availability of gas-fired generation could be hampered by insufficient gas-supplies stemming from production (e.g., well-head freeze offs), contracting practices (e.g., non-firm, interruptible service), and uncoordinated response to pipeline system conditions (e.g., pipeline fractures, pressure limits).<br><br>Communications and coordination between two industries are hampered by the incompatibility between the traditional gas day, traditional electric day, and the market day (in market areas), which increases the difficulty of the gas industry providing the needed services to its largest consumer. Additionally, pipeline communications and coordination have generally continued between pipeline system operators and its customers—generators, not Reliability Coordinators or Balancing Authorities.<br><br>Contracting practices also make it difficult to plan the flexibility needed for both industries' reliable operation. A coordinated approach for engaging the two industries to come together and develop compromising solutions to address operational strategies, operational changes, and tariff changes is critical. In some cases, vital information needed for the reliable operation of the bulk power system is not exchanged or shared with system operators from both industries.<br><br>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, the outages and derates from inadequate gas supply during the cold weather event totaled 1,294 MW, compared to a peak net capacity reduction of 14,453 MW. While gas supply to Salt River Project and El Paso Electric was compromised due to problems at the Chevron Keystone Storage Facility, those utilities' generators failed for other reasons. However, during the 2003 cold weather event, there were significant gas curtailments to electric generators in Texas, which affected generating capacity. |

| | | |
|---|---|---|
| | **Remaining Uncertainties** | • Federal policies for mitigating dependency on any one fuel, regulatory changes, and tariff modifications to reflect growing concern of interdependency |

## Emerging Issue #RAS-4: *Geomagnetic Disturbance Impacts to System Operations and Communications*

| Emerging Issue | Item | Specifics |
|---|---|---|
| Horizon | **Number of years** | On-going and beyond |
| Status | **Emerging or Standing** | Emerging |
| | **Technical Group** | Geomagnetic Disturbance Task Force |
| Background | **Description** | The NERC GMDTF Interim Report forecast that the most likely result from a strong geomagnetic disturbance is voltage collapse. NERC also accepted that particularly large geomagnetically induced current (GIC) flows can result in transformer damage, and may ultimately result in the failure of some transformers. The industry is well-equipped to face a small number of transformer failures; however, due to the concerns about an extreme GMD event causing a larger than expected number of failures, it is important to carefully quantify the nature of the reliability risk. |
| | **What changes during the 10-year horizon?** | The solar peak occurs in May 2013, but large earth directed solar flares can occur at any time and could have widespread impact on bulk power system operations. |
| | **What is the impact to regional reliability?** | Regions that are situated on top of areas with high ground conductivity may be at greater risk for the introduction of GIC into the bulk power system. These currents can impact real-time operations and equipment, depending on the duration and severity of the occurrence. |
| Assessment Factors | **Resource Adequacy Considerations** [Yes/No]? | Yes. System study and analysis is needed to determine the potential contingencies that may develop and the impact of units' availability to be dispatched to provide reactive support during the onset of a large geomagnetic storm. |
| | **Transmission Adequacy Considerations** [Yes/No]? | Yes. System study and analysis is needed to determine the potential contingencies that may develop from the introduction of large GIC into the bulk power system. |
| | **Resource Siting Impacts** [Yes/No]? | No |
| | **Operations Impacts** [Yes/No]? | Yes. Real-time operations could be impacted as reactive demands increase as transformers experience thermal heating from geomagentically induced currents. If reactive demands and geomagnetic currents are not properly monitored, situations could develop where an uncontrolled cascade of the bulk power system due to the introduction of geomagnetically induced currents ultimately resulting in voltage collapse. |

| | | |
|---|---|---|
| | **Remaining Uncertainties** | Yes. NERC will be performing a wide-area transformer vulnerability assessment to determine the potential impacts to the bulk power system from a large geomagnetic disturbance. The results of this work will be reviewed through the Geomagnetic Disturbance Task Force and the NERC Planning Committee and Operating Committee. |
| Additional Comments | | For more information and background on the impact of Geomagnetic Disturbances, please reference the *2012 Special Assessment: GMDTF Interim Report – Affects of Geomagnetic Disturbances on the bulk power system.* |

## Emerging Issue #RAS-5: Transmission Siting and Permitting

| Emerging Issue | Item | Specifics |
|---|---|---|
| Horizon | **Number of years** | On-going and beyond |
| Status | **Emerging or Standing** | Standing |
| | **Technical Group** | Reliability Assessment Subcommittee |
| Background | **Description** | Siting difficulties have always been difficult for utilities. Siting of new bulk power transmission lines brings with it unique challenges due to the high visibility, their span through multiple states and/or provinces and, potentially, the amount of coordination/cooperation required among multiple regulating agencies and authorities. Lack of consistent and agreed upon cost allocation approaches (specific to transmission construction), coupled with public opposition due to land-use and property valuation concerns, have, at times, resulted in long delays in transmission construction. When construction is delayed, special operating procedures to maintain bulk power system reliability may be needed. For example, it took the American Electric Power Company fourteen years to obtain siting approval for a 90-mile 765 kV transmission project, while it required only two to construct it.<br><br>Province and State Renewable Portfolio Standards (RPS) will increase renewable resources located where wind power densities and solar development are favorable. U.S. federal RPS is also under consideration in Congress. Grid expansion is needed to support the dispersed nature of renewable resources. Finally, additional generation sources, especially large plants such as nuclear facilities, may require grid expansion to assure deliverability. The limited timeframe provided to meet RPS mandates requires that the current siting and approval processes be expedited to ensure meeting mandated energy requirements. |
| | **What changes during the 10-year horizon?** | Significant change in resource mix |
| | **What is the impact to regional reliability?** | Lack of sufficient transmission to support a changing resource mix |
| Assessment Factors | **Resource Adequacy Considerations** [Yes/No]? | Yes. Should needed transmission not be completed in time, generating capacity may not be fully deliverable and derates in resources could occur. |
| | **Transmission Adequacy Considerations** [Yes/No]? | Yes. Transmission projects missing target completion dates could result in insufficient transmission potentially causing transmission constraints. |
| | **Resource Siting Impacts** [Yes/No]? | Yes. Difficulties in transmission siting is the primary concern. |

| | | |
|---|---|---|
| | **Operations Impacts** [Yes/No]? | Yes. Operational measures and procedures may need to be implemented where transmission is not available. |
| | **Remaining Uncertainties** | • Permitting and approval process<br>• Project timeline<br>• Project costs |

## Emerging Issue #RAS-6: Potential Operational Risks Associated with Interaction of SPS/RAS

| Emerging Issue | Item | Specifics |
|---|---|---|
| Horizon | **Number of years** | On-going and beyond |
| Status | **Emerging or Standing** | Emerging |
| | **Technical Group** | System Protection and Control Subcommittee (SPCS) |
| Background | **Description** | Increasingly, Special Protection Systems (SPS) are being installed in lieu of transmission facilities. While an SPS is a less costly alternative to new transmission facilities, and faster to install, there are instances where an SPS has failed to operate and in other instances where activating an SPS has resulted in additional unforeseen operational issues with negative reliability consequences.<br><br>The deployment of an SPS often results in adding operational complexity to the grid operators. The lack of a modeling guide for planning SPS may have contributed to incomplete evaluation of the operational impacts of an SPS on the reliability of the power system.<br><br>The objective of this emerging issue is to:<br>1) Evaluate historical and future trends in SPS deployment,<br>2) Identify operational risks associated with SPS deployment and proliferation,<br>3) Propose a framework for assessing consequences associated with SPS deployment, and<br>4) Propose modeling and assessment needs. |
| | **What changes during the 10-year horizon?** | • Risks of failure,<br>• Planning and operational complexity |
| | **What is the impact to regional reliability?** | Inadequate modeling and analysis of an impact of SPS operations and interactions may result in more optimistic results in both operational and planning time frames. |
| Assessment Factors | **Resource Adequacy Considerations** [Yes/No]? | No. |
| | **Transmission Adequacy Considerations** [Yes/No]? | Yes. |
| | **Resource Siting Impacts** [Yes/No]? | No. |

| | | |
|---|---|---|
| | **Operations Impacts** [Yes/No]? | Yes. The complexity of operating with SPSs may increase. |
| | **Remaining Uncertainties** | |

## Emerging Issue #RAS-6: Potential Operational Risks Associated with Interaction of SPS/RAS

| Emerging Issue | Item | Specifics |
|---|---|---|
| Horizon | **Number of years** | On-going and beyond |
| Status | **Emerging or Standing** | Emerging |
| | **Technical Group** | System Protection and Control Subcommittee (SPCS) |
| Background | **Description** | Increasingly, Special Protection Systems (SPS) are being installed in lieu of transmission facilities. While an SPS is a less costly alternative to new transmission facilities, and faster to install, there are instances where an SPS has failed to operate and in other instances where activating an SPS has resulted in additional unforeseen operational issues with negative reliability consequences.<br><br>The deployment of an SPS often results in adding operational complexity to the grid operators. The lack of a modeling guide for planning SPS may have contributed to incomplete evaluation of the operational impacts of an SPS on the reliability of the power system.<br><br>The objective of this emerging issue is to:<br>1) Evaluate historical and future trends in SPS deployment,<br>2) Identify operational risks associated with SPS deployment and proliferation,<br>3) Propose a framework for assessing consequences associated with SPS deployment, and<br>4) Propose modeling and assessment needs. |
| | **What changes during the 10-year horizon?** | • Risks of failure,<br>• Planning and operational complexity |
| | **What is the impact to regional reliability?** | Inadequate modeling and analysis of an impact of SPS operations and interactions may result in more optimistic results in both operational and planning time frames. |
| Assessment Factors | **Resource Adequacy Considerations** [Yes/No]? | No. |
| | **Transmission Adequacy Considerations** [Yes/No]? | Yes. |
| | **Resource Siting Impacts** [Yes/No]? | No. |

| | | |
|---|---|---|
| | **Operations Impacts** [Yes/No]? | Yes. The complexity of operating with SPSs may increase. |
| | **Remaining Uncertainties** | |

## Emerging Issue #RAS-7: Global Supply Chains and Fuel Reliability

| Emerging Issue | Item | Specifics |
|---|---|---|
| Horizon | **Number of years** | On-going and beyond |
| Status | **Emerging or Standing** | Emerging |
| | **Technical Group** | None |
| Background | **Description** | Supply chains are used in almost every industry to coordinate sourced resources from supplier to customer. Supply chains are systematic, incorporating a series of organizations, people, technology, activities, and information. Risk management theory tells us that supply chain disruptions are a function of the vulnerabilities associated with a given chain. Furthermore, vulnerabilities are a function of chain length and weakness—the more "chains" there are in the supply chain, the greater the likelihood there may be for a disruption; consequently, the weaker the "chains" are, the greater the likelihood there may be for a disruption.<br><br>Reliance on global supply chains for fuel and other products used to generate electricity must be managed with a common goal of reducing the risk of a prolonged disruption. The electric industry has a reputation for risk adversity; therefore, discrete or short disruptions in the supply chain are less likely to cause great issue—operational and strategic plans are often put in place to deal with a low occurrence event. However, large and prolonged supply chain impacts could disrupt the ability for a given power plant, or group of power plants, to produce electricity and, therefore, cause significant reliability concerns.<br><br>Of specific concern are global supply chains that are made up of weak chains (e.g., political uncertainty and instability, war stricken states, weak ties to North American foreign affairs). Currently, there are two known supply chains of specific concern to the electric power industry: 1) scarcity of rare earth metals for nuclear generation[1] and 2) liquefied natural gas imports from the middle east. |
| | **What changes during the 10-year horizon?** | Fuel quality/availability for electric generators; potential for disruption or inability to acquire fuel and/or other supplies |
| | **What is the impact to regional reliability?** | Prolonged disruptions could impact the ability of multiple generators to produce electricity. |
| Assessment Factors | **Resource Adequacy Considerations** [Yes/No]? | Yes. Prolonged disruptions could impact the ability of multiple generators to produce electricity. |

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|---|---|---|
| | **Transmission Adequacy Considerations** [Yes/No]? | No. |
| | **Resource Siting Impacts** [Yes/No]? | No. |
| | **Operations Impacts** [Yes/No]? | Yes. Prolonged disruptions could impact the ability of multiple generators to produce electricity. |
| | **Remaining Uncertainties** | • Availability of supplies<br>• Domestication of supplies<br>• Energy security policies |

# Emerging Issue #RAS-8: Assessment of Fault-Induced Delayed Voltage Recovery (FIDVR) Simulations

| Emerging Issue | Item | Specifics |
|---|---|---|
| Horizon | **Number of years** | On-going and beyond |
| Status | **Emerging or Standing** | Standing |
| | **Technical Group** | System Analysis and Modeling Subcommittee |
| Background | **Description** | Fault-Induced Delayed Voltage Recovery (FIDVR) events are characterized by a depressed voltage for 5 to 30 seconds following a fault. These events are of concern because they show a temporary loss of voltage control in an area, and they pose a risk of cascading to a larger area, especially if another unexpected event occurs while the voltage is depressed. These events have been studied and are believed to be initiated by the stall of low-inertia induction motors during the fault. Motors at risk of stalling include compressor-driving loads such as air conditioners. The subject of FIDVR events, their causes and solutions is covered in a NERC white paper on this topic.[1]<br><br>The following recurring issues need to be addressed:<br>• The FIDVR phenomenon must be more universally broadcast and understood throughout the electric utility planning community.<br>• Dynamic load models adequate for FIDVR studies should be developed, communicated, and appropriately customized for local use by grid planners.<br>• Post Event Analysis has been vital in finding model deficiencies and implementing corresponding improvements and should be promoted.<br>• Understanding and proper planning of power system protection and control action is important in preventing FIDVR events, which often are initiated by single-phase-to-ground faults that progress to multi-phase-to-ground faults because of protection inadequacy or failure.<br>• The degree of urgency that should be assigned to FIDVR studies is directly related to the degree of air conditioning load penetration. Guidelines or standards should not be issued to require the same level of effort from Alaskan planners as from those in California, Texas, Arizona, or Florida.<br>• Unit level protection should be standardized for residential air conditioners to remove them from service for under-voltage conditions and lower FIDVR risk. |

[1] http://www.nerc.com/docs/pc/tis/FIDV_R_Tech_Ref_V1-1_PC_Approved.pdf

| | | |
|---|---|---|
| | **What changes during the 10-year horizon?** | Load characteristics (increasing low-inertia air conditioning loads without compressor under-voltage protection) that may increase FIDVR risk. |
| | **What is the impact to regional reliability?** | Insufficient dynamic planning models do not accurately assess FIDVR risk. Significant load loss due to motor protective device action can result, as can significant loss of generation, with a potential secondary effect of high system voltage due to load loss. A severe event can result in fast voltage collapse. |
| Assessment Factors | **Resource Adequacy Considerations** [Yes/No]? | No. This issue is more related to operational reliability and system security. |
| | **Transmission Adequacy Considerations** [Yes/No]? | Yes. FIDVR events expose transmission risks. New transmission can reduce FIDVR vulnerability. However, in some cases, new transmission can also allow a fault to reduce voltages over a wider area during the fault, so each situation needs to be carefully analyzed. This information can be used to install transmission based dynamic Mvars, or for targeting regions for potential new generation. |
| | **Resource Siting Impacts** [Yes/No]? | Yes. The effectiveness of dynamic support is very dependent on its location. Dynamic simulation studies should be conducted to determine sites where dynamic support will provide optimal FIDVR mitigation. This information can be used to install transmission based dynamic Mvars, or for targeting regions for potential new generation. |
| | **Operations Impacts** [Yes/No]? | Yes. Special Protection Schemes (SPS) may be used as a safety net to confine the area impacted by FIDVR. If a voltage collapse develops in a load center because of a multi-contingency event, an SPS can contain the disturbance from spreading to larger grid. |
| | **Remaining Uncertainties** | • Planning studies have not been able to replicate FIDVR events very accurately due to inaccurate modeling of loads. Uncorrected, this modeling deficiency has a two-fold detrimental effect. First, it can result in studies that do not adequately identify potential FIDVR events. Second, it can give false confidence in mitigation plans designed to prevent reoccurrence of events.<br>• Synchrophasor use for operational preparations and FIDVR mitigation |

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

June 20, 2012

Members, Reliability Coordinating Committee
and
Members, Task Force on Coordination of Operation
Members, Task Force on Coordination of Planning
Members, Task Force on Infrastructure Security and Technology
Members, Task Force on System Protection
Members, Task Force on System Studies

Re: Minutes of the March 1, 2012 Reliability Coordinating Committee Meeting

Sir / Madam:

Attached are the minutes of the March 1, 2012, meeting of the NPCC Reliability Coordinating Committee, as approved at the June 13, 2012 meeting.

Sincerely,

*Phil Fedora*

Philip A. Fedora
Assistant Vice President-Reliability Services

cc: NPCC Staff

**NORTHEAST POWER COORDINATING COUNCIL**
**Reliability Coordinating Committee Minutes**
**March 1, 2012**

Mr. Gates called the meeting of the Reliability Coordinating Committee (RCC), held at Consolidated Edison, New York, New York, on March 1, 2012 to order at 10:00 am.

## Attendance

**Officers of the Reliability Coordinating Committee**

| | |
|---|---|
| Donald L. Gates, Chair | ISO-New England |
| Alden Briggs, Co-Vice Chair | New Brunswick System Operator |
| Michael Schiavone, Co-Vice Chair | National Grid USA |

**Sector 1 - Transmission Owners**

| | |
|---|---|
| Central Hudson Gas & Electric Corp. | Thomas Duffy (via phone) |
| Central Maine Power Company | Dave Conroy - Alternate |
| Consolidated Edison Company of New York, Inc. | Peter Yost - Alternate |
| Hydro One Networks Inc. | Paul Tremblay |
| Long Island Power Authority | (proxy to Anie Philip) |
| National Grid USA | Michael Schiavone |
| New Brunswick Power Transmission Corporation | Randy MacDonald – Alternate (via phone) |
| New York Power Authority | Michael Parisi – Alternate (via phone) |
| New York State Electric & Gas Corp. | (proxy to John Allen - via phone) |
| Northeast Utilities | Brad Bentley |
| Nova Scotia Power Incorporated | Paul Casey |
| Rochester Gas & Electric Corporation | John Allen (via phone) |
| United Illuminating Company | Jonathan Appelbaum – Alternate (via phone) |
| Vermont Transco | Paul Renaud |

**Sector 2 – Reliability Coordinators**

| | |
|---|---|
| Hydro-Québec TransÉnergie | (via written proxy) |
| Independent Electricity System Operator | Barbara Constantinescu (via phone) |
| ISO-New England, Inc. | Donald L. Gates |
| New Brunswick System Operator | Alden Briggs |
| New York Independent System Operator | Henry Chao |

**Sector 3 – Transmission Dependent Utilities, Distribution Companies and Load Serving Entities**

| | |
|---|---|
| Hydro-Québec Distribution | Stephane Dufrense (via phone) |
| Long Island Power Authority | Anie Philip - Alternate |

| | |
|---|---|
| New York Power Authority | (proxy to Mike Parisi) |
| Northeast Utilities | Dwayne Basler |

**Sector 4 Generation Owners**

| | |
|---|---|
| Dominion Energy Marketing, Inc. | Mike Garton (via phone) |
| Dynegy, Inc. | James Watson (via phone) |
| Entergy Nuclear Northeast | Tom Czerniewski |
| Long Island Power Authority | (proxy to Anie Philip) |
| New York Power Authority | (proxy to Mike Parisi – via phone) |
| NextEra Energy Resources | (via written proxy) |
| Northeast Utilities | (proxy to Dwayne Basler) |
| Ontario Power Generation, Inc. | David Ramkalawan |

**Sector 5 – Marketers, Brokers, and Aggregators**

| | |
|---|---|
| Constellation Energy Commodities Group, Inc. | Glen McCartney (via phone) |
| Hydro-Quebec energy Marketing, Inc. | (proxy to Scott Leuthauser) |
| Hydro Québec Energy Services (US) Inc. | Scott Leuthaser – Alternate (via phone) |
| Long Island Power Authority | (proxy to Anie Philip) |
| New York Power Authority | (proxy to Mike Parisi – via phone) |
| PPL EnergyPlus LLC | Bradley Weghorst (via phone) |
| Utility Services | (via written proxy) |

**Sector 6 – State and provincial Regulatory and/or Governmental Authorities**

| | |
|---|---|
| New York Power Authority | (proxy to Mike Parisi – via phone) |
| New York State Department of Public Service | Ed Schrom |

**Sector 7 – Sub-Regional Reliability Councils, Customers, other Regional Entities and Interested Entities**

| | |
|---|---|
| New York State Reliability Council, LLC | (via written proxy) |

**NPCC Staff**

| | |
|---|---|
| Javier Echevarria | Information Technology Specialist |
| Maritza Feliciano | Office Manager & Executive Assistant |
| Phil Fedora | Assistant Vice President, Reliability Services |
| Brian Hogue | Information Systems & Security Management |
| Donal Kidney | Manager, System Studies |

| | |
|---|---|
| Stanley Kopman | Assistant Vice President of Compliance Registration & Enforcement |
| Quoc Le | Manager, System Planning & Protection |
| John Mosier, Jr. | Assistant Vice President of System Operations |
| Frantz Roc | Manager, Information Technologies |
| Paul Roman | Manager, Operations Planning |
| Edward A. Schwerdt | President & Chief Executive Officer |
| Guy Zito | Assistant Vice President, Standards |

**Guests**

| | |
|---|---|
| Nickesha Carrol | Consolidated Edison |
| David A. Daley | Chair, Task Force on Coordination of Operation |
| Gregory Goodrich | Chair, Task Force on Infrastructure Security & Technology |
| Pedro Rebellon | IESO |
| Daren Verner (via phone) | Chair, Task Force on System Protection |
| Isen Widjaja (via phone) | Chair, SS-38 Working Group |

## Quorum Statement

Mr. Fedora indicated that a quorum had been achieved, by member attendance, proxy or alternate designation. He also noted having received the following written proxies:

Sector 2 – Reliability Coordinators
Pierre Paquet – Hydro-Quebec TransEnergie

Sector 5 – Marketers, Brokers and Aggregators
Brian Evans-Mongeon – Utility Services

## Antitrust Guidelines for NPCC Meetings

Mr. Fedora reviewed the NPCC Antitrust Guidelines in the Agenda package, and suggested contacting NPCC Inc.'s Assistant Secretary, Andrianne S. Payson, at (212) 424-8218 for further information.

## President & CEO Report

Mr. Schwerdt reported that the NERC Board of Trustees unanimously approved the NPCC Regional Reliability Standard on Underfrequency Load Shedding (UFLS) at its February 9, 2012 meeting. That approval came after a series of questions from the

NERC Board of Trustees regarding the specifics of NPCC's UFLS standard, including: the provision for compensating load shedding (a concept that seemed foreign to many in the room). Additionally, with its approval of Regional Reliability UFLS Standards for SERC and now NPCC, the NERC Board questioned the level of coordination occurring in other Regional Entities. From an NPCC perspective, this is a good thing and will potentially move the NERC framework of Planning Coordinator UFLS plans (there are some 81 PCs in North America), to a more regionally focused approach. Lastly, the NERC Board of Trustees asked more generically about the status of the fill-in-the-blank standards, and a report on regional standards efforts will be presented at the May 2012 NERC Board meeting.

With regards to the 2012–2015 ERO-wide Strategic Plan, NERC management and the Regional Entity executives, working collaboratively, developed a strategic plan that is designed to move from a regime of legalistic-based, check the box compliance enforcement to a risk-informed reliability performance focused approach. The NPCC Board, at its February 1, 2012 meeting, concurred that that vision was directionally correct, especially when coupled with a commitment to improved efficiencies and the cost effective use of resources. The challenge will be to get there from here. In its Regional Entity implementation of the ERO Strategy in 2012, it is NPCC's goal by this time next year to have advanced standards development, focused compliance, established reliability assessment metrics that are meaningful to measure, and to have in place a Bulk Electric System implementation and exception process that is efficient, technically sound and minimally disruptive to NPCC's continuing commitment to reliability excellence.

As a part of that commitment to reliability excellence, NPCC staff has been tasked to work collaboratively with the Task Force on System Protection's SP-7 Working Group on Protection System Misoperation Review to initiate an outreach program to the membership targeting the causes of relay-misoperations, with the objective of achieving measureable reductions in the quarterly reported data for NPCC. Distributed with the agenda package for today's meeting are relay misoperation statistics for portions of 2011, both from a NERC perspective and from an NPCC perspective. While NPCC does not itself have a significant problem in the relay misoperations area, neighboring Regional Entities clearly do. As NPCC addresses its issues, exporting those lessons learned could go a long way to decreasing the likelihood of a power tsunami once again invading the Northeast. The NERC Performance Analysis Subcommittee (PAS) during a recent presentation on common and dependent mode transmission outage trends identified failed protection system equipment as contributing factors in both common mode and dependent mode outages. Disturbingly, the NERC PAS found that there was not a correlation between those outages and violations of PRC-005 (the relay maintenance standard). This could suggest that the standard isn't "scratching the itch" and that

targeted PRC-005 enforcement to address relay misoperations isn't a sure pathway to increased reliability. It may be, more appropriately, time to re-engineer a solution to relay misoperations, and the excellence of NPCC's performance and technical expertise in this area puts NPCC at the forefront. The challenge is there for NPCC to accept. He strongly recommended NPCC wholehearted accept that challenge.

## Chair Report

**Meeting Agenda**

Mr. Gates stated there were no changes to the Agenda provided in the Agenda Package.

**The RCC then approved the Agenda.**

**NPCC website password change**

Mr. Fedora reminded the RCC that the NPCC website password now changes every 90 days; notice to the NPCC membership will be provided on that basis.

**RCC Scope**

Mr. Fedora indicated the NPCC Board approved a conforming change to the RCC Scope to reflect that the members of the RCC will be appointed by the NPCC Board of Directors, in accordance with the sectors outlined in the *Amended and Restated Bylaws of Northeast Power Coordinating Council, Inc.*, effective January 1, 2012.

**RCC 2012-2013 RCC Work Plan**

Mr. Fedora stated the NPCC Board approved 2012-2013 RCC Work Plan has been included in the Agenda package.

**Location of June and September RCC Meetings**

Mr. Fedora indicated that the June and September RCC Meetings will be held at the New York Office of Dewey, Lebouef; details regarding the arrangements will be provided prior to the meetings.

## Consent Agenda

The Reliability Coordinating Committee approved (with one abstention – Brian Evans-Mongeon, Utility Services) the following Consent Agenda items:

**November 29, 2011 Meeting Minutes**

The Draft-For-Approval Minutes of the November 29, 2011 Reliability Coordinating Committee were approved with corrections noted.

NPCC, Inc.

**NORTHEAST POWER COORDINATING COUNCIL**
**Reliability Coordinating Committee Minutes**
**March 1, 2012**

## RCC Membership Changes

Approved at the NPCC February 1, 2012 Board Meeting:

Sector 3 - Transmission Dependent Utilities ("TDUs"), Distribution Companies and Load, -Serving Utilities

- ✓ Ms. Anie Philip of Long Island Power Authority as an alternate, replacing Mr. Steve Marron.

Approved at the November 30, 2011 NPCC Board Meeting:
Sector 4 - Generator Owners

- ✓ Mr. Allen D. Schriver, P.E. of NextEra Energy Resources as a member, replacing Mr. Benjamin Church.

## Task Force Roster Changes

The following changes to Task Force and Working Group memberships were approved:

### Task Force on System Studies

- ✓ Ms. Joy Brake of Nova Scotia Power, Inc. will serve as the alternate.
- ✓ Mr. Alex Rost steps down as the NBSO representative; pending changes within New Brunswick's electricity sector, he will not be replaced by another NBSO employee.

### Task Force on System Protection

- ✓ Mr. Jacob Wernhoff replaces Mr. Frank Ettori as the member, both of Vermont Electric Power Company, Inc.
- ✓ Ms. Gian Pauletto of Vermont Electric Power Company, Inc. will serve as the alternate.
- ✓ Mr. Robert Austenfeld will serve as the alternate representing Central Maine Power Company, New York State Electric and Gas Corporation and Rochester Gas & Electric Corporation.
- ✓ Mr. Jay Nair of Nova Scotia Power, Inc. will serve as the alternate.
- ✓ Mr. Ovidiu Vasilachi of Independent Electricity System Operator will serve as the alternate.

### Task Force on Coordination of Planning

- ✓ Mr. Brad Bentley of Northeast Utilities replaces Mr. Alden Briggs of New Brunswick System Operator as Chair.
- ✓ Mr. Scott Brown replaces Mr. Alden Briggs as the member, both of New Brunswick System Operator.
- ✓ Mr. Alden Briggs replaces Mr. Scott Brown as the alternate.
- ✓ Mr. Marc Dusseault of HQ TransEnergie replaces Mr. Brad Bentley of Northeast Utilities as Vice-Chair.
- ✓ Mr. Mario Pilot of HQ TransEnergie will serve as the alternate.

**CP-8 Working Group on Review of Resource and Transmission Adequacy**

- ✓ Mr. Dragan Pecurica of Nova Scotia Power, Inc. will serve as the alternate.

**SS-37 Working Group on Base Case Development**

- ✓ Ms. Ting Zhang replaces Ms. Joy Brake as a member, both of Nova Scotia Power Inc.
- ✓ Ms. Joy Brake of Nova Scotia Power Inc. will serve as the alternate.
- ✓ Mr. Mahmoud Matar Bayoumi replaces Mr. Ted Slugocki as the alternate, both of the Independent Electricity System Operator.

**SS-38 Working Group on Inter-Area Dynamic Analysis**

- ✓ Mr. Sunil Palla replaces Mr. Han Huang as the member, both of New York Power Authority.
- ✓ Mr. Alex Rost steps down as the NBSO representative; due to pending changes within New Brunswick's electricity sector, Alex will not be replaced by another NBSO employee.

**CO-12 Operations Planning Working Group**

- ✓ Ms. Kamala Rangaswamy of Nova Scotia Power, Inc. will serve as the alternate.
- ✓ Mr. Yan Bechamp of the IESO will replace Ms. Griselda Matos as the IESO CO-12 representative and will replace Mr. Rod Hicks of New Brunswick System Operator as the CO-12 Chair.

**CO-2 System Operator Training Working Group**

- ✓ Mr. Stephen George of ISO-New England will become the ISO-New England representative and will serve as the new Chair, replacing Mr. Rod Pettenuzzo of IESO.
- ✓ Ms. Sarah Stainton will replace Mr. Rod Pettenuzzo as the IESO CO-2 representative.

**New York Interim Transmission Review of Resource Adequacy**

Approved as provided in the Agenda package.

**Updated SS-38 Working Group Scope**

Approved as provided in the Agenda package, with corrections noted.

**2011 NPCC Long Range Adequacy Overview**

Approved as provided in the Agenda package.

**TFSS-SPS List, Major Projects List, BPS list, and DCT Exclusions List**

Approved as provided in the Agenda package.

# Reliability Coordinating Committee Actions

**Modification of the Bruce Type I Special Protection System (SPS)**

Mr. Gates asked the RCC to consider holding a brief teleconference on April 30, 2012 (at 1:00 pm EDT) to consider an additional change to this SPS to coordinate with the commissioning of two new 500 kV Bruce to Milton circuits.

Mr. Rebellon explained the enhancements detailed in the Agenda package to the existing Bruce SPS required to accommodate the return to service of the remaining two generating units at the Bruce complex, while also providing the capability to arm appropriate responses for an expanded range of contingency conditions.

He explained that these proposed enhancements and modifications are necessary to ensure that the system in the Bruce area can continue to be operated reliably with up to eight generating units in-service at the Bruce Complex, together with all of the committed wind-turbine generating facilities being installed in the same area.

He indicated that the Task Force on Coordination of Planning concurred with the findings of the other Task Forces that these enhancements of the Bruce SPS continue to be Type I, and recommends RCC approval.

Mr. Rebellon further informed the RCC that two new 500 kV circuits from the Bruce nuclear complex to the Milton SS will be included in the Bruce Type I SPS. With the commissioning of these new circuits it is anticipated that the Bruce SPS will be armed only during transmission outages, depending on system conditions.

Given that the in-service date of these new circuits has been advanced from late 2012 to spring 2012, the IESO is planning to present this modification to the Task Force on Coordination of Operation on March 27, 2012, the Task Force on System Studies on March 29, 2012, and the Task force on Coordination of Planning on April 17, 2012. This change has already been reviewed and approved by the Task Force on System Protection. Assuming the other Task Force approvals, the IESO will be seeking RCC approval of this SPS modification at a conference call meeting scheduled for April 30, 2012.

**The NPCC Reliability Coordinating Committee then approved the Modification of the Bruce Type I SPS NPCC (with one abstention– Brian Evans-Mongeon, Utility Services), as provided in the Agenda package, and agreed to consider an change associated with the operation of the new Bruce to Milton circuits at a teleconference scheduled for April 30, 2010 at 1:00 pm.**

Ms. Constantinescu expressed her thanks to the RCC for accommodating the IESO request.

**SS-38 Load Modeling White Paper – Terms of Reference and Study Schedule**

Mr. Widjaja presented the Terms of Reference and Study Schedule for the subject Load Modeling White Paper, as described in the Agenda package. The white paper will be developed by the SS-38 Working Group and will be reviewed with TFSS prior to its submission for approval at the November 2012 RCC meeting.

**The RCC approved (with one abstention – Brian Evans-Mongeon, Utility Services) the SS-38 Working Group Load Modeling White Paper Terms of Reference and Study Schedule as provided in the Agenda package.**

**NPCC Directory No. 6 – Reserve Sharing**

Mr. Daley reviewed the draft of NPCC Directory No. 6 - Reserve Sharing provided in the Agenda package. He explained that Directory No. 6 was developed by the Task Force on Coordination on Operation (TFCO) in order to provide the criteria for NPCC Balancing Authorities to participate in a Reserve Sharing Group. Directory No. 6 provides the specific requirements that individual agreements governing Reserve Sharing Groups' will conform to and it replaces NPCC Procedure C-38 *Procedure for Operating Reserve Assistance* which was retired in 2010.

He explained Directory No. 6 was posted to the NPCC Open Process Review for a 45 day comment period from September 8, 2011 to October 24. 2011 and the TFCO has responded to all comments received. Pending RCC approval, the draft Directory No. 6 will be submitted to the NPCC Full Members for ballot approval.

He provided the following clarifications discussed at the NPCC Task Force Chairs review yesterday:

R2.1
NPCC Members of an RSG shall obtain Reliability Coordinating Committee (RCC) approval prior to going into effect, including any future changes developed by the RSG.

Replace With:

New RSG Agreements, and future changes to existing RSG agreements, must be approved by the Reliability Coordinating Committee (RCC).

R3
The Balancing Authorities (BAs) participating in a Reserve Sharing Group (RSG) shall be adjoining BAs, unless they have a wheeling agreement with the intermediary BA, or BAs.

The, "or BAs", was added to the end of R3

Mr. Schwerdt stated asked that reference to the January 1, 2012 NPCC Bylaws be included.

**The NPCC Reliability Coordinating Committee then approved (with one abstention – Brian Evans-Mongeon, Utility Services) the NPCC Directory No. 6 – Reserve Sharing for NPCC membership ballot, with the clarifying corrections presented.**

**A-10 Implementation Plan and Waiver Requests**
Mr. Gates asked the RCC to deferred action on this item (to the June meeting), pending additional reliability analysis supporting the waiver requests.

**The RCC agreed to defer consideration of this Agenda Item until the June 13, 2012 RCC meeting.**

**2012 NPCC Summer Reliability Assessment**
Mr. Roman gave a presentation of the preliminary finding of the NPC 2012 Summer Reliability Assessment provided in the Agenda package; Mr. Fedora reviewed the preliminary results of the corresponding NPCC Multi-Area Probabilistic Reliability Assessment and the schedule for Task Force and RCC approval.

Mr. Fedora added that the Media Event releasing the 2012 NPCC Summer Reliability Assessment has been scheduled for May 3, 2011 at 11:00 am. A summary of the assessment will be provided at the May 1, 2012 NPCC Board meeting.

## Status Reports

Mr. Gates referred the RCC to the materials provided in the Agenda package; the RCC discussed the following Agenda items:

**NPCC Regional Standards Committee (RSC) Report**
Mr. Zito highlighted the following items from the materials provided in the Agenda package:

- ✓ The Underfrequency Loadshedding NPCC Regional Standard was approved by the NERC Board of Trustees on February 9, 2012 ; he thanked the SS-38 Working Group

and the Task Force on System Studies for the significant effort they expended in the review of this Regional Standard.

- ✓ The NPCC Board approved the revised Scope for Regional Standard Committee – it calls for active Task Force technical assistance in the review of Compliance Application Notices (CANS) as they are issued.
- ✓ Beginning in January, 2012 a triage process has been adopted; the RSC will be soliciting technical input from the Task Forces regarding specific aspects of the draft Standards.

**NPCC Reliability Directory Status**

Mr. Zito reported on Task Force activities supporting the Phase 2 Directory development.

**NPCC Compliance Committee Report**

Mr. Kopman highlighted two activities related to the materials provided in the Agenda package:

- ✓ NERC Reliability Registered Entity Risk Assessment (a/k/a Entity Impact Evaluation).
- ✓ Enforcement violation processing and the development of metrics.

**Task Force on Coordination of Operations (TFCO) Directory No. 5 Follow-up**

Mr. Daley reviewed the status report provided in the Agenda package; the TFCO will respond to the one comment received from the Open Posting and will be working on revisions to the Appendices.

**2012-2013 Task Force Work Plan Progress**

Task Force on Coordination of Operation (TFCO)

Mr. Daley highlighted the TFCO's progress on Directories No. 6 and No. 5, as well as the work with the Task Force on Coordination of Planning on Directory No.1. He added that a Reserve Sharing Drafting Team has been formed.

Task Force on Coordination of Planning (TFCP)

Mr. Bentley provided an update on the status of Directory No. 1 work.

Task Force on Infrastructure Security & Technology (TFIST)

Mr. Hogue stated that the CIP version 5 will be posted at least once more for comment – NERC intends to send to FERC by the September timeframe. He also noted plans for a TFIST CIP version 5 November/December Workshop.

Task Force on System Protection (TFSP)

Mr. Vernen referred the RCC to the TFSP report provided in the Agenda package.

Task Force on System Studies (TFSS)
Mr. Conroy highlighted the completion of the updates to the annual lists; the Maritimes Area Comprehensive Transmission Review is expected to be approved at the June RCC Meeting.

**NPCC Reliability Assessment Program (NRAP) Highlights Report**
Mr. Fedora indicated that the NPCC Reliability Assessment Program Highlights Report has been be updated as of February 24, 2012 and is posted on the NPCC website.

## NERC Highlights and Agenda Items

**Operating Committee (OC)**
Mr. Mosier reviewed three approval items on the March 2012 Operating Committee Agenda:

- ✓ ACE Diversity Interchange White Paper
- ✓ Severe Impact Resiliency Task Force Report
- ✓ Event Driven Index White Paper

**Planning Committee (PC)**
Mr. Fedora said that the Severe Impact Resiliency Task Force Report and the Event Driven Index White Paper are also on the March 2012 NERC Planning Committee Agenda for approval, as well as approval for the following topics:

- ✓ Reliability Assessment Data Working Group Scope
- ✓ Model Validation Working Group Scope
- ✓ Systems Analysis and Modeling Subcommittee Scope
- ✓ Bulk Electric System Phase 2 Standard Drafting Team assignments to address the technical justifications for:
  - the 100 kV voltage level;
  - the 20/75 MVA generator threshold;
  - the reactive resource threshold level; and,
  - power flow out of Local Networks.

**Critical Infrastructure Protection Committee (CIPC)**
Mr. Hogue highlighted the following topics on the March 2012 NERC Critical Committee Agenda:

- ✓ Coordinated Action Plan related activities:
  - Formation of a Cyber Attack Task Force;
  - CIPC endorsement of the Severe Impact Resiliency Task Force Report;
  - Update on the Geomagnetic Disturbance Task Force; and,
  - Discussion of the Spare Equipment Data Base Task Force.
- ✓ Update on CIP version 5
- ✓ Compliance Application Notices – CAN 17 concerns (CIP requirements on passwords)
- ✓ Creation of new CIPC Subgroups

## Informational Items

Mr. Gates referred the RCC to the materials included in the Agenda package. The following Informational Items were discussed at the meeting:

**Events Analysis Program**

Mr. Mosier reported that following the past Events Analysis field trails, the NERC Board of Trustees approved a final process document for this effort at its February meeting. He indicated it is expected that NERC will be scheduling future Webinars to roll out the process.

Mr. Schwerdt mentioned that there was a suggestion that the Events Analysis process be codified into the NERC Rules of Procedure; the NERC Board of Trustees deferred action on that suggestion, so that NERC would not be locked into a procedural document that would require FERC approval to change.

He stated that NPCC remains committed to timely dissemination of the lessons learned from the events to the industry.

**NERC Geomagnetic Disturbance Task Force (GMDTF) Report**

Mr. Fedora said that the GMDTF report has been approved by the NERC Board of Trustees, and was publically released yesterday. One of the recommendations/call to action regards the modeling and simulation of the expected impacts from these types of disturbances. He referred the RCC to a public PESRC WebEx on this topic; the details of the WebEx were previously distributed to the RCC.

**NERC Bulk Electric System Definition**

Mr. Fedora summarized the materials provided in the Agenda package regarding the status of the revision to the Bulk Electric System Definition and related Phase 2 activities of the Standard Drafting Team.

**FERC staff Mercury and Air Toxics Standards (MATS) White Paper**

Mr. Fedora said that the White Paper in included in the Agenda package outlines the FERC staff's position on how the Commission should advise the EPA (under the EPA's Policy Memorandum) regarding requests for extensions of time to comply with EPA's Mercury and Air Toxics Standards.

**NPCC Operational Highlights**

Mr. Roman reported on the Task Force of Coordination of Operation's discussion of the recent occurrence of off-peak high transmission voltages and the voltage control practices used to control them.

**Eastern Interconnection Planning Collaborative (EIPC)**
Mr. Gates provided an overview of the EIPC activities provided in the Agenda package.

**Eastern Interconnection Reliability Assessment Group (ERAG)**
Mr. Roman explained the ERAG efforts to improve the modeling and simulation of Eastern Interconnection frequency response and initiatives aimed at industry entities (Generator Owners and Operators and Transmission Owners and Operators) to improve the accuracy of models used for dynamic simulations.

## Other Matters

Having no other items to consider, the RCC meeting was then adjourned.

| **Next RCC Meeting Date** | **Location** |
|---|---|
| April 30, 2012 (1:00 pm EDT) | Teleconference |
| June 13, 2012 | Dewey Lebouef , New York, NY |

**Distribution of Approved Minutes**
NPCC Full & General Member Representatives and Alternates
Members, NPCC Board of Directors
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Members, NPCC Public Information Committee
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Members, NPCC Regional Standards Committee
Members, NPCC Task Force on Coordination of Operation
Members, NPCC Task Force on Coordination of Planning
Members, NPCC Task Force on Infrastructure Security and Technology
Members, NPCC Task Force on System Protection
Members, NPCC Task Force on System Studies
NPCC Officers
NPCC Staff
Andrew J. Fawbush, Esq.
Catherine P. McCarthy, Esq.
Andrianne S. Payson, Esq.
and
Federal Energy Regulatory Commission – Joseph McClelland
La Régie de L'Énergie – Caroline Dupuis
Ontario Energy Board – Peter Fraser
United States Department of Energy – David Meyer
New Brunswick Department of Energy – Stephen Waycott
Nova Scotia Utility & Review Board – S. Bruce Outhouse, Q.C.

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

June 20, 2012

Members, Reliability Coordinating Committee
and
Members, Task Force on Coordination of Operation
Members, Task Force on Coordination of Planning
Members, Task Force on Infrastructure Security and Technology
Members, Task Force on System Protection
Members, Task Force on System Studies

Re: Minutes of the April 30, 2012 Reliability Coordinating Committee Meeting

Sir / Madam:

Attached are the minutes of the April 30, 2012 meeting of the NPCC Reliability Coordinating Committee, as approved at the June 13, 2012 meeting.

Sincerely,

*Phil Fedora*

Philip A. Fedora
Assistant Vice President-Reliability Services

cc: NPCC Staff

**NORTHEAST POWER COORDINATING COUNCIL**
**Reliability Coordinating Committee Minutes**
**April 30, 2012**

Mr. Gates called the meeting of the Reliability Coordinating Committee (RCC), held via teleconference on April 30, 2012 to order at 1:00 pm.

## Attendance (via teleconference)

**Officers of the Reliability Coordinating Committee**

| | |
|---|---|
| Donald L. Gates, Chair | ISO-New England |
| Alden Briggs, Co-Vice Chair | New Brunswick System Operator |
| Mike Schiavone, Co-Vice Chair | National Grid USA |

**Sector 1 - Transmission Owners**

| | |
|---|---|
| Central Hudson Gas & Electric Corp. | (proxy to Frank Pace) |
| Central Maine Power Company | Dave Conroy (Alternate) |
| Consolidated Edison Company of New York, Inc. | Mike Forte |
| Hydro One Networks Inc. | Paul Tremblay |
| Long Island Power Authority | (proxy to Anie Philip) |
| National Grid USA | Mike Schiavone |
| New York Power Authority | Michael Parisi – Alternate |
| New York State Electric & Gas Corp. | Raymond Kinney |
| Northeast Utilities | Brad Bentley |
| Nova Scotia Power Incorporated | David Stanford -Alternate |
| Rochester Gas & Electric Corporation | John Allen |
| United Illuminating Company | Jonathan Appelbaum – Alternate |
| Vermont Transco | Paul Renaud |

**Sector 2 – Reliability Coordinators**

| | |
|---|---|
| Hydro-Québec TransÉnergie | Pierre Parquet |
| Independent Electricity System Operator | Barbara Constantinescu |
| ISO-New England, Inc. | Donald L. Gates |
| New Brunswick System Operator | Alden Briggs |
| New York Independent System Operator | Henry Chao |

**Sector 3 – Transmission Dependent Utilities, Distribution Companies and Load Serving Entities**

| | |
|---|---|
| Hydro-Québec Distribution | Stephane Dufrense |
| Long Island Power Authority | Anie Philip - Alternate |
| New York Power Authority | (proxy to Mike Parisi) |
| Northeast Utilities | (proxy to Brad Bentley) |

**Sector 4 Generation Owners**

| | |
|---|---|
| Dominion Energy Marketing, Inc. | Mike Garton |
| Dynegy, Inc. | (via written proxy) |
| Entergy Nuclear Northeast | Tom Czerniewski |
| Long Island Power Authority | (proxy to Anie Philip) |
| New York Power Authority | (proxy to Mike Parisi) |
| NextEra Energy Resources | (via written proxy) |
| Northeast Utilities | (proxy to Brad Bentley) |

**Sector 5 – Marketers, Brokers, and Aggregators**

| | |
|---|---|
| Constellation Energy Commodities Group, Inc. | (via written proxy) |
| Hydro Québec Energy Services (US) Inc. | Scott Leuthaser – Alternate |
| Long Island Power Authority | (proxy to Anie Philip) |
| New York Power Authority | (proxy to Mike Parisi) |
| PPL EnergyPlus LLC | Bradley Weghorst |
| Utility Services | (via written proxy) |

**Sector 6 – State and provincial Regulatory and/or Governmental Authorities**

| | |
|---|---|
| New York Power Authority | (proxy to Mike Parisi) |
| New York State Department of Public Service | Ed Schrom |

**Sector 7 – Sub-Regional Reliability Councils, Customers, other Regional Entities and Interested Entities**

| | |
|---|---|
| New York State Reliability Council, LLC | Roger Clayton |

**NPCC Staff**

| | |
|---|---|
| Jack Alvarez | Senior Engineer |
| Phil Fedora | Assistant Vice President, Reliability Services |
| Paul Roman | Manager, Operations Planning |

**Guests**

| | |
|---|---|
| Pedro Rebellon | IESO |
| Howard Tarler | New York ISO |

## Quorum Statement

Mr. Fedora indicated that a quorum had been achieved, by member attendance, proxy or alternate designation. He also noted having received the following written proxies:

Sector 4 – Generator Owners
James Watson – Dynegy Inc.
Allen Schriver – NextEra Energy Resources

Sector 5 – Marketers, Brokers and Aggregators
Glen McCartney – Constellation Energy Commodities Group, Inc.
Brian Evans-Mongeon – Utility Services

## Antitrust Guidelines for NPCC Meetings

Mr. Fedora reviewed the NPCC Antitrust Guidelines in the Agenda package, and suggested contacting NPCC Inc.'s Assistant Secretary, Andrianne S. Payson, at (212) 424-8218 for further information.

## Chair Report

**Meeting Agenda**

Mr. Gates stated there were no changes to the Agenda as provided in the Agenda Package.

**The RCC then approved the Agenda.**

## Reliability Coordinating Committee Actions

**Modification of the Bruce Type I Special Protection System (SPS)**

Ms. Constantinescu explained the enhancements to the Bruce Type I SPS due to the anticipated completion of the two new 500 kV circuits between the Bruce nuclear complex and the Milton S/S. With the commissioning of these new circuits in the spring of 2012, it is anticipated that the Bruce SPS will need to be armed only to manage transmission outages, depending on system conditions.

Mr. Rebellon reviewed the technical modification to this SPS and the operating conditions that will be included in its functionality that was provided in the Agenda package. As indicated in the transmittal letter provided in the Agenda package, the modification of this SPS was reviewed and accepted by the Task Force on System Protection, the Task Force on System Studies and the Task Force on Coordination Operations. The Task Force on Coordination of Planning concurred with the findings of the other Task Force and recommends RCC approval.

**The NPCC Reliability Coordinating Committee then approved the Modification of the Bruce Type I SPS NPCC, as provided in the Agenda package, with two abstentions (Glen McCartney, Constellation Energy Commodities Group, Inc. and Brian Evans-Mongeon, Utility Services).**

**NPCC Reliability Assessment for Summer 2012**

Mr. Gates offered the following revisions (shown by ~~strikethrough~~ and highlight below) due to recent developments in New England.

In the Executive Summary (Page 2):

> New England forecasts a summer peak demand of 26,462 MW with a minimum projected 3,023 MW net margin for its peak week, which is the same as the forecasted coincident NPCC peak week. The margin does not include the short-term capacity and energy purchases from neighboring systems that are anticipated to help serve the electrical demands on the system. Reduced and uncertain fuel supplies to Northeast Massachusetts/Boston resources will cause local capacity margins to be tight under high load conditions.

In the Executive Summary (Page 3):

> Delete bullet that reads:
>
> ~~No particular fuel deliverability problem is foreseen by any of the Reliability Coordinator areas.~~

In the New England Paragraph (Page 26):

> Historically, fuel supply and delivery options have been readily available to generators within New England during the summer months. For the summer of 2012, ISO New England does not foresee ~~any~~ system-wide fuel supply or delivery constraints. In the Northeast Massachusetts/Boston area, reduced and uncertain fuel supplies to Northeast Massachusetts /Boston resources will cause localized capacity margins to be tight under high load conditions. ~~However~~ In addition, New England's dependence on natural gas to fire combined cycle generation requires close coordination with natural gas pipeline companies as well as major LNG companies as part of its communications protocol.

Mr. Chao reported on clarifying corrections to the assumptions associated with the New York extreme load forecast since the posting of the subject report in the Agenda package.

Mr. Fedora also indicated that editorial changes had been received and would also be incorporated into the report.

**The NPCC Reliability Coordinating Committee then approved the NPCC Reliability Assessment for Summer 2012 as provided in the Agenda package and discussed at the meeting, with one abstention (Brian Evans-Mongeon, Utility Services).**

## Other Matters

Mr. Fedora noted the following change in location for the next RCC Meetings:

| RCC Meeting Date(s) | Location |
|---|---|
| June 13, 2012 | **RCC PreMeeting** - NPCC Board Room, 1040 Avenue of the Americas, FL 10, New York, NY 10018 from 8:00 a.m. to 9:30 a.m. |
| September 12, 2012 | **RCC Meeting** - Residence Inn by the Marriott, (located diagonally across the NPCC Offices) at 1033 Avenue of the Americas, FL 3, New York, NY from 10:00 a.m. to 3:00 p.m. |

Having no other items to consider, the RCC meeting was then adjourned.

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