From: Goodman, Kathleen
To: ben@benli.ca; david.kiguel@HydroOne.com
Cc: rscmembers
Subject: Standards Committee Items
Date: Monday, December 19, 2011 11:00:09 AM

Guys:

One item came up this morning w/r/t the CIP Standard V5. There is no general "catch all" question on the comment form as we have seen in the past. There are very pointed questions – and MANY of them – but none that says "anything else you want to tell us?" The RSC would like this to be brought to the Standards Committee as a general process issue.

Also, I have a general concern with the concurrent voting and commenting on every standards project that is posted. I had thought the industry supported this approach for getting projects through that are in "jeopardy" and not for every project. I believe this is making the process less effective and would like the SC to have a general discussion about the intent of the concurrent balloting.

Thanks.

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From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Regional Reliability Standards Announcement - Comment Period Open for BAL-004-WECC-02 | January 23 – March 9, 2012
Date: Monday, January 23, 2012 12:27:50 PM

Regional Reliability Standards Announcement

Comment Period Open for BAL-004-WECC-02
January 23 – March 9, 2012

Regional Project: Now available

Proposed Standard for the Western Electricity Coordinating Council (WECC)
WECC has requested NERC to post regional reliability standard BAL-004-WECC-02 Contingency Reserves for a 45-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 Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the regional standards development page.

Background
BAL-004-WECC-02 retains the requirement for Balancing Authorities to compute the Automatic Time Error Correction and Primary Inadvertent Interchange by 50 minutes after the hour and requires that Balancing Authorities have the ability to operate their Automatic Generation Control in other modes. In addition, Balancing Authorities are required to recalculate Primary Inadvertent Interchange when hourly and month-end adjustments are made.

In Version 3 in order to prevent the stranding of Secondary Inadvertent Interchange the drafting team added a Requirement R8 that restrictions the payback of Inadvertent Interchange to using ATEC rather than through bilateral and unilateral payback methods.

The proposed BAL-004-WECC-02 will replace the Automatic Time Error Correction definition in the NERC Glossary of Terms in the WECC Regional Definitions section. The WECC definitions for Primary Inadvertent Interchange and Secondary Inadvertent Interchange will be retained under the WECC Regional Definitions in the Glossary of Terms Used in NERC Reliability Standards. A new definition "Automatic Timer Error Correction – ATEC" is included in this standard.

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.

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~~Standard BAL-004-WECC-01 — Automatic Time Error Correction~~

~~A. Introduction~~

~~Title: Automatic Time Error Correction~~

Document Title	WECC Standard BAL-004-WECC-02
File Name	
Category	(X) Regional Reliability Standard ( ) Regional Criterion ( ) Policy ( ) Guideline ( ) Report or other ( ) Charter
Document date	
Adopted/approved by	
Date adopted/approved	
Custodian (entity responsible for maintenance and upkeep)	
Stored/filed	Physical location: Web URL:
Previous name/number	(if any)
Status	( ) in effect ( ) usable, minor formatting/editing required ( ) modification needed ( ) superseded by _____ ( ) other _____ ( ) obsolete/archived)

Version Control

Version	Date	Action	Change Highlights
1	4/15/2011	Version 1 Posted	Addressed FERC Order 723
2		Version 2 Posted 11/4/11	Addressed comments from Version 1 posting
3		Version 3 Posted 12/15/11	Addressed comments from Version 2 posting
4		Standing Committee Approval	
5		WECC Board Approval	

WECC 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.

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Development Steps Completed:

Completed Actions	Completion Date
1. Request received	09/26/2009
2. Requested deemed Complete/Valid/Team Site created	10/06/2009
3. Pre-SRRC announcement	10/16/2009
4. SRRC notified	10/26/2009
5. SRRC assigned the Request to Standing Committee 6. Due to lack of manpower/resources this Request was placed on hold until July 2010 by Mr. Don Watkins, OC chair	11/2009
7. Assigned to the Performance Work Group by Mr. Hulls, incoming OC chair	07/16/2010
8. Drafting team (DT) announced / notice sent to DT members	07/16/2010
9. Notice of development / first 30-day notice	09/2/2010
10. New committee chair orientation meeting	08/18/2010
11. First DT meeting	11/10/2010
12. Notice of Concurrence sent by DT (see step 3) 13. New meeting announcement / also included in first meeting minutes	11/10/2010
14. DT meetings completed	12/15/10 01/18/11 02/10/11 03/11–12/11 03/24/11 04/11/11
15. Complete first draft and Complete Quality Control Checklist	04/13/2011
16. Post first draft for 45-day comment period	04/15/2011
17. Meet to answer to comments, address impact statement and draft responses	06/2-3/2011 06/14/2011 06/23/2011 06/29/2011
18. Post responses to comments received during 45-day comment period	06/29/2011
19. Meet to answer to comments, address impact statement and draft responses	08/8/2011 08/15/2011 08/30/2011 11/01/2011
20. Post the Version 2 for a 30-day comment period	11/04/2011
21. Post consideration of comments of Version 2	12/15/2011
22. Post the third dart for 30-day comment period	12/15/2011
23. Project WECC-0068 Version 3 Comments were due	01/16/2012
24. Meeting to answer comments, address impact statement, draft	01/18/2012

Completed Actions	Completion Date
responses	
25. Post responses to comments	02/13/2012
26. Post for Operating Committee approval	02/24/2012

Description of Current Draft:

On May 21, 2009, the Federal Energy Regulatory Commission (Commission or FERC) issued a Final Rule approving WECC Regional Reliability Standard BAL-004-WECC-1 – Automatic Time Error Correction (BAL-004-WECC-1) and directing WECC to make several clarifying modifications to the standard using the FERC-approved Process for Developing and Approving WECC Standards.[1] In addition, WECC staff identified additional modifications to BAL-004-WECC-1 that would clarify the intent without changing the requirements. Finally, the industry has commented that there is confusion concerning BAL-004-WECC-1 Requirement R3 that requires that the Area Control Error (ACE) equation used for North American Electric Reliability Corporation (NERC) reports shall be the same ACE equation as that used during Automatic Generation Control (AGC) mode. This seems to conflict with NERC's comments in response to the Notice of Proposed Rulemaking regarding the interpretation of NERC Reliability Standard BAL-001-0.1a – Real Power Balancing Control Performance (BAL-001-0.1a)[2] wherein NERC stated that entities may use an Automatic Time Error Correction (ATEC) ACE equation for control but should use raw ACE for CPS reporting.[3] As part of this filing WECC has submitted a proposed regional variance to BAL-001-0.1a to address this conflict.

The purpose of the refinements to BAL-004-WECC-1 as proposed in WECC Regional Reliability Standard BAL-004-WECC-2 – Automatic Time Error Correction (BAL-004-WECC-2) is to implement the directives in FERC Order 723 and to make other clarifications to BAL-004-WECC-1 as the industry deems necessary, while maintaining the Western Interconnection's reliability. The FERC Order 723 directives are as follows:

1. "The Commission is concerned that the phrases 'large accumulation' and 'in such a situation' as used in Requirement R1.2 leaves to individual interpretation when a 'large' amount of primary inadvertent has accumulated. The ERO and WECC agree that the provision could benefit from further clarity. Accordingly, the Commission adopts its NOPR proposal and directs WECC to develop revisions to the provision so that a balancing authority will know with specificity the circumstances that trigger the actions required by Requirement R1.2."[4]
2. "Consistent with the NOPR, pursuant to section 215(d) (5) of the FPA, the Commission directs WECC to develop a modification to the regional Reliability Standard consistent with WECC's and NERC's explanation that the limit set forth in Requirement 2 of '24 hours per calendar quarter' is an accumulated total for the period, resulting from either a singular event or a cumulative time limit from a number of events."[5]
3. "[The Commission] direct[s] that the violation risk factors assigned to BAL-004-WECC-01, Requirements R1, R2, R3, and R4 be modified from 'lower' to 'medium.' The ERO and WECC must submit a filing within 60 days of the effective date of this Final Rule that

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[1] *Western Electricity Coordinating Council Regional Reliability Standard Regarding Automatic Time Error Correction*, Order No. 723, 127 FERC Stats. & Regs. ¶ 61,176, 74 Fed. Reg. ¶ 25,422 (2009) (hereafter Order 723).

[2] *Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards*, Notice of Proposed Rulemaking, 123 FERC Stats. & Regs. ¶ 61,064, 73 Fed. Reg. ¶ 22,856 (2008).

[3] *Comments of the North American Electric Reliability Corporation on the Notice of Proposed Rulemaking regarding Interchange and Transmission Loading Relief under RM08-7*, pgs 9-10, FERC Docket No. RM08-7-000, filed June 12, 2008.

[4] Order 723 at ¶ 30.

[5] *Id* at ¶ 34.

includes the directed modifications."[6] These modifications were addressed in a compliance filing dated August 28, 2009. [7]

4. "The Commission adopts its NOPR proposal and directs the ERO and WECC to submit violation severity levels for each Requirement and sub-Requirement that has been assigned a violation risk factor. To allow adequate time for the development of the violation severity levels, the ERO and WECC must submit a filing within 120 days of the effective date of this Final Rule that includes the directed violation severity levels."[8] These modifications were addressed in a compliance filing date October 23, 2009.[9]
5. In response to Xcel comments, FERC referenced their approval, in Order No. 713, of an ERO interpretation stating that as long as Balancing Authorities use raw ACE for Control Performance Standard (CPS) reporting purposes and WECC ATEC (ATEC) ACE for control, it is not a violation of BAL-001-0.1a, Requirement 1.[10]. WECC Stakeholders believe it is more appropriate to use the ATEC ACE for control and CPS reporting. To clarify this difference, WECC has developed a regional variance BAL-001-0.1a.

The implementation of an ATEC ACE is part of a regional variance to BAL-001-0.1a associated with this posting. The purpose of this filing is to meet the directives of FERC Order 723 while refining for clarity the existing requirements of BAL-004-WECC-1. Refinements to BAL-004-WECC-1 include:

1. A requirement that defines the large accumulation at 150% of previous year's peak demand or peak generation for generation-only Balancing Authorities. The action required is that the Balancing Authority shall not permit the PII_{accum} to exceed the defined value, which is demonstrated at the end of each month.
2. A clarification in response to the FERC order that the accumulated time for ATEC out of service shall not exceed 24 hours during a calendar quarter.

BAL-004-WECC-2 retains the requirement for Balancing Authorities to compute the Automatic Time Error Correction and Primary Inadvertent Interchange by 50 minutes after the hour and requires that Balancing Authorities have the ability to operate their Automatic Generation Control in other modes. In addition, Balancing Authorities are required to recalculate Primary Inadvertent Interchange when hourly and month-end adjustments are made.

In Version 3 in order to prevent the stranding of Secondary Inadvertent Interchange the drafting team added a Requirement R8 that restrictions the payback of Inadvertent Interchange to using ATEC rather than through bilateral and unilateral payback methods.

The proposed BAL-004-WECC-2 will replace the Automatic Time Error Correction definition in the NERC Glossary of Terms in the WECC Regional Definitions section. The WECC definitions for Primary Inadvertent Interchange and Secondary Inadvertent Interchange will be retained under the WECC Regional Definitions in the *Glossary of Terms Used in NERC Reliability Standards*.

Development Plan:

Anticipated Actions	Anticipated Date
1. Post draft standard for 45-day NERC comment period	02/01/2012
2. NERC comment period ends	03/27/2012

[6] *Id* at ¶ 51.

[7] Compliance Filing of the North American Electric Reliability Corporation in response to Paragraphs 26 and 51 of Order No. 723 – Directed Modification of Violation Risk Factors for Regional Reliability Standard BAL-004-WECC-1, Automatic Time Error Correction, Docket No. RM08-12-000, filed August 28, 2009

[8] Order 723 at ¶ 54.

[9] Compliance Filing of the North American Electric Reliability Corporation in response to Paragraphs 26 and 54 of Order No. 723, Docket No. RM08-12-000, filed October 23, 2009

[10] Order 723 at ¶ 44-45.

3. Operating Committee approves proposed standard	03/27/2012
4. DT completes review and consideration of industry comments to NERC posting	04/27/2012
5. Post draft standard for WECC Board approval	05/01/2012
6. WECC Board approval	06/21/2012
7. Post draft standard for 15-day NERC comment period	06/25/2012
8. NERC 15-day comment period ends	07/2012
9. DT completes review and consideration of industry comments to NERC posting	07/2012
10. Submit NERC Board of Trustees approval request	08/2012
11. Receive NERC Board approval	08/2012

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Implementation Plan

The Implementation Plan is to make the WECC Regional Variance to BAL-001-0.1a and BAL-004-WECC-2 effective on the first day of the second quarter, after regulatory approval in areas where applicable. Since entities are already controlling their Balancing Authority Area with the ATEC ACE equation – but are reporting using the NERC raw ACE equation for reporting CPS1 – the transition to controlling and reporting using the ATEC ACE should be minimal. Additionally, it should not take much time to implement the limits to a Balancing Authority's Accumulated Primary Inadvertent Interchange.

Definitions of Terms Used in Regional Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the NERC Glossary under WECC Regional Definitions. In addition the current definitions for "**Primary Inadvertent Interchange**" and "**Secondary Inadvertent Interchange"** will be retained in the Glossary of Terms Used in NERC Reliability Standards under WECC Regional Definitions.*

Automatic Time Error Correction: The addition of a component to the ACE equation that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error.

A. Introduction

1. Title: Automatic Time Error Correction

2. Number: BAL-004-WECC-~~01~~02

3. Purpose: To maintain Interconnection frequency ~~**within a predefined frequency profile under all conditions (i.e. normal and abnormal), and**~~ and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the Interconnection.

4. Applicability~~:~~

4.1. Functional Entities

4.1. ~~1~~ Balancing Authorities ~~**(BA)**~~ that operate synchronously ~~**to**~~in the Western Interconnection.

5. Effective Date: On the first day of the ~~**first**~~second quarter, after applicable regulatory approval~~.~~ has been received (or the Reliability Standard otherwise becomes effective the first day of the fourth quarter following NERC Board adoption where regulatory approval is not required).

~~B. Requirements~~

~~**R1.** Each BA that operates synchronously to the Western Interconnection shall continuously operate utilizing Automatic Time Error Correction (ATEC) in its Automatic Generation Control (AGC) system. [Risk Factor: Lower]~~

$$ACE_{ATEC} = (NI_A - NI'_S) - 10B_i(F_A - F_S) - T_{0b} + I_{ME}$$

Where:

NI_A = Net Interchange Actual (MW).

F_A = Frequency Actual (Hz).

F_S = Frequency Scheduled (Normally 60 Hz).

B_i = Frequency Bias for the Balancing Authority's Area (MW / 0.1 Hz).

T_{0b} = Remaining Bilateral Payback for Inadvertent Interchange created prior to implementing automatic payback (MW).

I_{ME} = Meter Error Correction (MW).

$$NI'_S = NI_S - \frac{H^{on/off\ peak}_{Primary}}{(1 - Y) * H}$$

NI_S = Net Interchange Scheduled (MW).

$Y = B_i / B_S$.

H = Number of Hours used to payback Inadvertent Interchange Energy. The WECC Performance Work Group has set the value of H to 3.

B_S = Frequency Bias for the Interconnection (MW / 0.1 Hz).

$H^{on/off\ peak}_{primary}$ = is the Balancing Authority's accumulated primary inadvertent interchange in MWh. An On-Peak and Off-Peak accumulation accounting is required.

Where:

$$\Pi^{\text{on/off peak}}_{\text{primary}} = \text{last period's } \Pi^{\text{on/off peak}}_{\text{primary}} + (1-Y) * (H_{\text{actual}} - B_i * \Delta TE/6)$$

H_{actual} is the hourly Inadvertent Interchange for the last hour.

ΔTE is the hourly change in system Time Error as distributed by the Interconnection Time Monitor.

Where:

$\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE\ offset)$

TD_{adj} is any operator adjustment to the control center Time Error to correct for differences with the time monitor.

t is the number of minutes of Manual Time Error Correction that occurred during the hour.

TE offset is 0.000 or +0.020 or -0.020.

R1.1. The absolute value of the WECC Automatic Time Error Correction term is limited as follows:

$$\left| \frac{H_{primary}^{on/off\ peak}}{(1-Y)\cdot H} \right| \leq L_{max}$$

Where L_{max} is chosen by the Balancing Authority and is bounded as follows:

$0.20 * |B_i| \leq L_{max} \leq L_{10}$

L_{10} is the Balancing Authority CPS2 limit in MW. If the WECC Automatic Time Error Correction term is less than the upper limit, use the calculated WECC Automatic Time Error Correction term.

R1.2. Large accumulations of primary inadvertent point to an invalid implementation of ATEC, loose control, metering or accounting errors. A BA in such a situation should identify the source of the error(s) and make the corrections, recalculate the primary inadvertent from the time of the error, adjust the accumulated primary inadvertent caused by the error(s), validate the implementation of ATEC, set L_{max} equal to L_{10} and continue to operate with ATEC reducing the accumulation as system parameters allow.

R2. Each BA that is synchronously connected to the Western Interconnection and operates in any AGC operating mode other than ATEC shall notify all other BAs of its operating mode through the designated Interconnection communication system. Each BA while synchronously connected to the Western Interconnection will be allowed to have ATEC out of service for a maximum of 24 hours per calendar quarter, for reasons including maintenance and testing. [Risk Factor: Lower]

6. Background:

In February 2003, the WECC Automatic Time Error Correction (ATEC) Procedure (Procedure) became effective for all Balancing Authorities in the Western Interconnection. The original intent of the Procedure was to minimize the number of Manual Time Error Corrections in the Western Interconnection. ATEC provides the added benefit of a superior approach over the current NERC Reliability Standard BAL-004-0 – Time Error Correction for assigning costs and providing for the equitable payback of Inadvertent Interchange. In October 2006, the Procedure became a WECC Criterion. In May 2009, FERC issued Order No.723 that approved Regional Reliability Standard BAL-004-WECC-1 - Automatic Time Error Correction, as submitted by NERC. In addition, the Commission directed WECC to develop several clarifying modifications to BAL-004-WECC-1 using the FERC-approved Process for Developing and Approving WECC Standards. The Effective Date of the BAL-004-WECC-1 standard was July 1, 2009. BAL-004-WECC-1 required Balancing

Authorities within the Western Interconnection to maintain Interconnection frequency within a predefined frequency profile and to ensure that Time Error Corrections were effectively conducted in a manner that did not adversely affect the reliability of the Interconnection. In September 2009, WECC received WECC Standards/Regional Criterion Request Form (Request) WECC-0068, which was a request for modification of BAL-004-WECC-1. In July 2010, the chair of the WECC Operating Committee assigned the Request to the Performance Work Group (PWG) for development.

B. Requirements and Measures

R1. Following the conclusion of each month each Balancing Authority shall verify that the absolute value of its Accumulated Primary Inadvertent Interchange (PII_{accum}) for both the monthly On-Peak period and the monthly Off-Peak period are each individually less than or equal to:

1.1. For load-serving Balancing Authorities, 150% of the previous calendar year's integrated hourly Peak Demand,

1.2. For generation-only Balancing Authorities, 150% of the previous calendar year's integrated hourly peak generation.

[Violation Risk Factor Medium:] [Time Horizon: Operations Assessment]

M1. Forms of acceptable evidence of compliance with Requirement R1include but are not limited to any one of the following:

- Data, screen shots from the WECC Interchange Tool (WIT),
- Data, screen shots from the internal Balancing Authority tool, or
- Production of data from any other databases, spreadsheets, displays.

R2. Each Balancing Authority shall, upon discovery of an error in the calculation of PII_{hourly}, recalculate within 90 days, the value of PII_{hourly} and adjust the PII_{accum} from the time of the error. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. Forms of acceptable evidence of compliance with Requirement R2 include but are not limited to any one of the following:

- Data, screen shots from the WIT,

Rationale for R1:

Premise: Each Balancing Authority should ensure that the absolute value of its PII_{accum} for both the On-Peak period and the Off-Peak period each individually does not exceed 150% of the previous year's Peak Demand for load-serving Balancing Authorities and 150% of the previous year's peak generation for generation-only Balancing Authorities. The Balancing Authority is required to take action to keep each PII_{accum} period within the limit. For example, the Balancing Authorities actions may include:

- Identifying and correcting the source of any metering or accounting error(s) and recalculating the hourly Primary Inadvertent Interchange (PII_{hourly}) and the PII_{accum} from the time of the error;
- Validating the implementation of ATEC; or
- Setting L_{max} equal to L_{10} until the PII_{accum} is below the limit in Requirement R1.

Justification: PII_{accum} may grow from month-end adjustments and metering errors, even with the inclusion of I_{ATEC} in the ACE equation.

Goal: To limit the amount of PII_{accum} that a Balancing Authority can have at the end of each month.

Rationale for R2:

Premise: When a Balancing Authority finds an error in the calculation of its PII, the Balancing Authority needs time to correct the error and recalculate PII and PII_{accum}.

Justification: The drafting team selected 90 days as a reasonable amount of time to correct an error and recalculate PII and PII_{accum}, since recalculation of PII and PII_{accum} is not a real-time operations reliability issue.

Goal: To promote the timely correction of errors in the calculation of PII and PII_{accum}.

Authority from withdrawing ATEC participation, for example, for economic gain during selected hours. If the limits were increased to 60 hours, a Balancing Authority could technically withdraw ATEC participation for one hour from Monday to Friday.

Goal: To promote fair and timely payback of PII_{accum} balances.

- Data, screen shots from the internal Balancing Authority tool, or
- Production of data from any other databases, spreadsheets, displays.

R3. Each Balancing Authority shall keep its Automatic Time Error Correction (ATEC) in service, with an allowable exception period of less than or equal to an accumulated 24 hours per calendar quarter for ATEC to be out of service. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

M3. Forms of acceptable evidence of compliance with Requirement R3~~. BAs in the Western Interconnection~~ may include, but are not limited to:

- Dated archived files,
- Historical data,
- Other data that demonstrates the ATEC was out of service for less than 24 hours per calendar quarter.

R4. Each Balancing Authority shall compute the following by 50 minutes after each hour:

4.1. PII_{hourly},

4.2. PII_{accum},

4.3. Automatic Time Error Correction term (I_{ATEC}).

[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]

Rationale for R4:

Premise: PII_{hourly}, PII_{accum}, and I_{ATEC} should be determined before the next scheduling hour begins.

Justification: To promote timely calculations 50 minutes was selected because it is before the next hour ramp begins and permits time to collect the data and resolve interchange metering values.

Goal: To promote the timely calculation of PII_{hourly}, PII_{accum}, and I_{ATEC}.

M4. Forms of acceptable evidence of compliance with Requirement R4 include but are not limited to any one of the following:

- Data, screen shots from the WECC Interchange Tool that demonstrate compliance,
- Data, screen shots from internal Balancing Authority tool that demonstrate compliance, or
- Data from any other databases, spreadsheets, displays that demonstrate compliance.

R5. Each Balancing Authority shall be able to change ~~their AGC~~its Automatic Generation Control operating mode between Flat Frequency (for blackout restoration); Flat Tie Line (for loss of frequency telemetry); Tie Line Bias; and Tie Line Bias plus Time Error ~~control~~Control (used in ATEC

Rationale for R5:

Premise: The ACE equation, and hence the AGC mode, will contain any number of parameters based on system operating conditions. Various AGC modes are identified corresponding to those operating conditions, as well as the specific sets of parameters included in the ACE equation.

Justification: Changing to the proper operating mode, corresponding to current operating conditions, affords proper movement of generating units in response to those conditions. The addition of the ATEC term results in an additional AGC mode and a different set of parameters. The inability to correctly calculate the ATEC term would dictate that AGC not be operated in the ATEC mode.

Goal: To set the AGC mode and calculate ACE in a manner that corresponds to the system operating conditions and to accommodate changes in those conditions.

mode~~). The ACE used for NERC reports shall be the same ACE as the AGC~~), to correspond to current operating ~~mode in use. [~~conditions. *[Violation Risk Factor: ~~Lower~~]Medium] [Time Horizon: Real-Time Operations]*

~~**R4.** Regardless~~**M5.** Forms of acceptable evidence of compliance with Requirement R5 include but are not limited to any one of the ~~AGC operating mode each BA in the Western Interconnection~~ following:

- Screen shots from Energy Management System,
- Demonstration using an off-line system.

R6. Each Balancing Authority shall ~~compute its~~ recalculate the PII_{hourly} and PII_{accum} for the On-Peak and Off-Peak periods whenever adjustments are made to hourly ~~Primary~~ Inadvertent Interchange ~~when hourly checkout is complete. If hourly checkout is not complete by 50 minutes after the hour, compute Primary~~ or ΔTE. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M6. Forms of acceptable evidence of compliance with Requirement R6 include but are not limited to any one of the following:

- Data, screen shots from the WECC Interchange Tool that demonstrate compliance,
- Data, screen shots from an internal Balancing Authority tool that demonstrate compliance with, or
- Data from any other databases, spreadsheets, displays that demonstrate compliance.

Rationale for R6:

Premise: Hourly adjustments to hourly Inadvertent Interchange (II) require a recalculation of the corresponding hourly PII value, the corresponding PII_{accum}, and all subsequent PII_{accum} for every hour up to the current hour.

Justification: As PII_{hourly} is corrected, then PII_{accum} should be recalculated.

Goal: To promote accurate, fair and timely payback of accumulated PII balances.

R7. Each Balancing Authority shall make the same adjustment to the PII_{accum} as it did for any month-end meter reading adjustments to Inadvertent Interchange ~~with best available~~. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M7. Forms of acceptable evidence of compliance with Requirement R7 include but are not limited to any one of the following:

- Data, screen shots from the WECC Interchange Tool that demonstrate compliance,

Rationale R7:

Premise: Month-end meter-reading adjustments are made, for example, when a Balancing Authority performs monthly comparisons of recorded month-end Net Actual Interchange (NI_A) values derived from hourly Actual Interchange Telemetered Values against month-end Actual Interchange Register Meter readings.

Justification: Month-end adjustments to II_{accum} are applied as 100% PII_{accum}. 100% was chosen for simplicity to bilaterally assign PII_{accum} to both Balancing Authorities, since the effect of this metering error on system frequency is not easily determined over the course of a month.

Goal: To provide a mechanism by which corresponding month-end II adjustments can be applied to PII_{accum}, when such adjustments cannot be attributed to any one particular hour or series of hours.

- Data, screen shots from an internal Balancing Authority tool that demonstrate compliance,
- Production of data~~. This hourly value shall be added to the appropriate accumulated Primary~~ from any other databases, spreadsheets, displays that demonstrate compliance.

R8. Each Balancing Authority shall payback Inadvertent Interchange ~~balance for either On-Peak or Off-Peak periods. [Risk Factor: Lower~~using ATEC rather than bilateral and unilateral payback. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

Rationale R8:

Premise: ATEC includes automatic unilateral payback of Primary Inadvertent Interchange and Secondary Inadvertent Interchange.

Justification: Additional unilateral and bilateral exchanges disturb the balance and distribution between Primary Inadvertent Interchange and Secondary Inadvertent Interchange throughout the Interconnection; thereby stranding Secondary Inadvertent Interchange.

Goal: To not strand Secondary Inadvertent Interchange.

~~**R4.1.** Each BA in the Western Interconnection shall use the change in Time Error distributed by the Interconnection Time Monitor.~~

~~**R4.2.** All corrections to any previous hour Primary~~ **M8**. Forms of acceptable evidence of compliance with Requirement R8 include but are not limited to historical On-Peak and Off-Peak Inadvertent Interchange ~~shall be added to the appropriate On- or Off-Peak accumulated Primary Inadvertent Interchange.~~

R4.3. Month-end Inadvertent Adjustments are 100% Primary Inadvertent Interchange and shall be added to the appropriate On- or Off-Peak accumulated Primary Inadvertentdata, data from the WECC Interchange, unless such adjustments can be pinpointed to specific hours in which case R4.2 applies. Tool, and ACE data.

R4.4. Each BA in the Western Interconnection shall synchronize its Time Error to the nearest

0.001 seconds of the system Time Error by comparing its reading at the designated time each day to the reading broadcast by the Interconnection Time Monitor. Any difference shall be applied as an adjustment to its current Time Error.

C. **Measures**

M1. For Requirement R1, a BA shall provide upon request a document showing that it is correctly calculating its hourly Primary Inadvertent Interchange number that is used to calculate its accumulated Primary Inadvertent Interchange and how it is used in its ACE equation for Automatic Time Error Correction.

M2. For Requirement R2, a BA shall record the date, time, reason, and notification [to other BAs within the Western Interconnection] for any time it is not operating utilizing Automatic Time Error Correction (ATEC) in its AGC system.

M3. For Requirement R3, a BA in the Western Interconnection must be able to demonstrate its ability to change its AGC operating mode when requested or during compliance audits and readiness reviews.

M4. For Requirement R4, a BA in the Western Interconnection must record its hourly Primary Inadvertent Interchange and keep an accurate record of its accumulation of Primary Inadvertent Interchange for both

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority.

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2 Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.3 Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority in the Western Interconnection shall retain the values of PII_{hourly}, PII_{accum} (On-Peak and Off-Peak ~~accounts. These records must be available for review when requested or during compliance audits and readiness reviews.~~

~~D. Compliance~~

~~1. Compliance Monitoring Process~~

~~1.1. Compliance Monitoring Responsibility~~

~~Regional Entity~~

~~Compliance Monitoring Period and Reset time Frame~~

~~The reporting period for ATEC is one calendar quarter, starting on the first second of the quarter and ending on the final second of the quarter.~~

~~The Performance-reset Period is one calendar quarter.~~

~~1.2. Data Retention~~

~~Each Balancing Authority in the Western Interconnection shall retain its hourly calculation of total and Primary Inadvertent Interchange calculated hourly, as well as the amount of Primary Inadvertent paid back hourly~~), ΔTE and any month-end adjustments for the preceding calendar year (January – December~~**) plus**~~), as well as the current calendar year.

~~Each Balancing Authority in the Western Interconnection shall retain its total accumulated Inadvertent and total Primary Inadvertent, updated hourly, for On- and Off-Peak for the preceding calendar year (January – December) plus the current year.~~

Each Balancing Authority in the Western Interconnection shall retain ~~its record of~~ the amount of time ~~it~~the Balancing Authority operated without ATEC ~~and the notification to the Interconnection of these times~~ for the preceding calendar year (January – December~~) plus~~), as well as the current ~~year.~~

~~The Compliance Monitor shall retain audit data for three~~ calendar ~~years~~year.

1.~~3.~~ 4 Additional Compliance Information

~~The Compliance Monitor shall use quarterly data to monitor compliance. The Compliance Monitor may also use periodic audits (on site, per a schedule), with spot reviews and investigations initiated in response to a complaint to assess performance.~~

~~The Balancing Authority in the Western Interconnection shall have the following documentation available for its Compliance Monitor to inspect during a scheduled, on-site review or within five business days of a request as part of a triggered investigation:~~

~~1.3.1. Source data for calculating Primary Inadvertent.~~

~~1.3.2. Data showing On- and Off-Peak Primary Inadvertent accumulations.~~

~~1.3.3. Data showing hourly payback of Primary Inadvertent.~~

~~1.3.4. Documentation on number of times not on ATEC and reasons for going off ATEC.~~

~~2. Violation Severity Levels~~

~~**2.1. Lower:** Time not in ATEC Mode greater than one day and less than or equal to three days, or if a Balancing Authority in the Western Interconnection operates without ATEC and does not notify other Balancing Authorities in the Western Interconnection 2 times in quarter.~~

~~**2.2. Moderate:** Time not in ATEC Mode greater than three days and less than or equal to five days, or if a Balancing Authority in the Western Interconnection operates without ATEC and does not notify other Balancing Authorities in the Western Interconnection 3 times in quarter.~~

~~**2.3. High:** Time not in ATEC Mode greater than five days and less than or equal to seven days, or if a Balancing Authority in the Western Interconnection operates without ATEC and does not notify other Balancing Authorities in the Western Interconnection 4 times in quarter.~~

~~**2.4. Severe:** Time not in ATEC Mode greater than seven days, or if a Balancing Authority in the Western Interconnection operates without ATEC and does not notify other Balancing Authorities in the Western Interconnection more than 4 times in quarter or Balancing Authority in the Western Interconnection cannot change AGC operating mode or Balancing Authority in the Western Interconnection incorrectly calculates Primary Inadvertent.~~

~~**Standard BAL-004-WECC-01 — Automatic Time Error Correction**~~

~~**Version History**~~

None

Table of Compliance Elements

Version R #	Date Time Horizon	Action VRF	Change Tracking Violation Severity Levels			
1	February 4, 2003	Effective Date.	New Lower VSL	Moderate VSL	High VSL	Severe VSL
1	October 17, 2006	Created Standard from Procedure.	Errata			
1	February 6, 2007	Changed the Standard Version from 0 to 1 in the Version History Table.	Errata			
1 R1	February 6, 2007 Operations Assessment	Medium	The upper limit bounds to the amount of Automatic Time Error Correction term was inadvertently omitted during the Standard Translation. The bound was added to the requirement R1.4. Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 150%, but was less than or equal to 160% of the previous calendar year's Peak Demand or peak	Errata Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 160%, but was less than or equal to 170% of the previous calendar year's Peak Demand or peak generation for generation-only Balancing Authorities.	Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 170%, but was less than or equal to 180% of the previous calendar year's Peak Demand or peak generation for generation-only Balancing Authorities.	Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 180% of the previous calendar year's Peak Demand or peak generation for generation-only Balancing Authorities.

~~Version #~~	~~Date~~Time Horizon	~~Action~~VRF	~~Change Tracking~~Violation Severity Levels			
~~1~~	~~February 4, 2003~~	~~Effective Date.~~	~~New~~Lower VSL	Moderate VSL	High VSL	Severe VSL
			generation for generation-only Balancing Authorities.			
~~1~~R2	~~February 6, 2007~~Operations Assessment	Medium	~~The statement "The Time Monitor may declare offsets in 0.001 second increments" was moved from TEoffset to TDadj and offsets was corrected to adjustments.~~The Balancing Authority did not recalculate PII_{hourly} and adjust the PII_{accum} within 90 days of the discovery of the error; but made the required recalculations and adjustments within 120 days.	~~Errata~~The Balancing Authority did not recalculate PII_{hourly} and adjust the PII_{accum} within 120 days of the discovery of the error; but made the required recalculations and adjustments within 150 days.	The Balancing Authority did not recalculate PII_{hourly} and adjust the PII_{accum} within 150 days of the discovery of the error; but made the required recalculations and adjustments within 180 days.	The Balancing Authority did not recalculate PII_{hourly} and adjust PII_{accum} within 180 days of the discovery of the error.
~~1~~R3	~~February 6, 2007~~Real-Time Operations	Medium	~~The reference to seconds was deleted from the TE offset term.~~The Balancing Authority operated	~~Errata~~The Balancing Authority operated during a calendar quarter without ATEC in service for more	The Balancing Authority operated during a calendar quarter without ATEC in service for more	The Balancing Authority operated during a calendar quarter without ATEC in service for more

~~Version~~R #	~~Date~~Time Horizon	~~Action~~VRF	~~Change Tracking~~Violation Severity Levels			
~~1~~	~~February 4, 2003~~	~~Effective Date.~~	~~New~~Lower VSL	Moderate VSL	High VSL	Severe VSL
			during a calendar quarter without ATEC in service for more than an accumulated 24 hours, but less than or equal to 72 hours.	than an accumulated 72 hours, but less than or equal to 120 hours.	than an accumulated 120 hours, but less than or equal to 168 hours	than an accumulated 168 hours.
~~1~~R4	~~June 19, 2007~~Operations Assessment	Medium	~~The standard number BAL-STD-004-1 was changed to BAL-004-WECC-01 to be consistent with the NERC Regional Reliability Standard Numbering Convention.~~The Balancing Authority did not compute PII_{hourly}, PII_{accum}, and I_{ATEC} within 50 minutes, but made the required calculations in less than or equal to two hours.	~~Errata~~The Balancing Authority did not compute PII_{hourly}, PII_{accum}, and I_{ATEC} within two hours, but made the required calculations in less than or equal to four hours.	The Balancing Authority did not compute PII_{hourly}, PII_{accum}, and I_{ATEC} within four hours, but made the required calculations in less than or equal to six hours.	The Balancing Authority did not compute PII_{hourly}, PII_{accum}, and I_{ATEC} within six hours.
R5	Real-Time Operations	Medium	N/A	N/A	N/A	The Balancing Authority is not able to change its AGC

~~Version #~~	~~Date~~Time Horizon	~~Action~~VRF	~~Change Tracking~~Violation Severity Levels			
~~1~~	~~February 4, 2003~~	~~Effective Date.~~	~~New~~Lower VSL	Moderate VSL	High VSL	Severe VSL
						operating mode between Flat Frequency (for blackout restoration; Flat Tie Line (for loss of frequency telemetry); Tie Line Bias; or Tie Line Bias plus Time Error control (used in ATEC mode).
R6	Operations Assessment	Medium	N/A	N/A	N/A	When making adjustments to hourly Inadvertent Interchange or ΔTE, the Balancing Authority did not recalculate the PII_{hourly} and the PII_{accum} for the On-Peak and Off-Peak periods.
R7	Operations Assessment	Medium	N/A	N/A	N/A	When making any month-end meter reading adjustments to Inadvertent Interchange, the Balancing Authority

~~Version #~~	~~Date~~Time Horizon	~~Action~~VRF	~~Change Tracking~~Violation Severity Levels			
~~1~~	~~February 4, 2003~~	~~Effective Date.~~	~~New~~Lower VSL	Moderate VSL	High VSL	Severe VSL
						did not make the same adjustment to the PII_{accum}.
R8	Operations Assessment	Medium	N/A	N/A	N/A	The Balancing Authority paid back Inadvertent Interchange using bilateral and unilateral payback rather than using ATEC.

~~5 of 5~~

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Requirement R4:

Requirement R5:

Requirement R6:

Requirement R7:

Requirement R8:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Comment Period Open for BAL-004-WECC-02
January 23 – March 9, 2012

Regional Project: Now available

Proposed Standard for the Western Electricity Coordinating Council (WECC)
WECC has requested NERC to post regional reliability standard BAL-004-WECC-02 Automatic Time Error Correction for a 45-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 Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the regional standards development page.

Background
BAL-004-WECC-02 retains the requirement for Balancing Authorities to compute the Automatic Time Error Correction and Primary Inadvertent Interchange by 50 minutes after the hour and requires that Balancing Authorities have the ability to operate their Automatic Generation Control in other modes. In addition, Balancing Authorities are required to recalculate Primary Inadvertent Interchange when hourly and month-end adjustments are made.

In Version 3 in order to prevent the stranding of Secondary Inadvertent Interchange the drafting team added a Requirement R8 that restrictions the payback of Inadvertent Interchange to using ATEC rather than through bilateral and unilateral payback methods.

The proposed BAL-004-WECC-02 will replace the Automatic Time Error Correction definition in the NERC Glossary of Terms in the WECC Regional Definitions section. The WECC definitions for Primary Inadvertent Interchange and Secondary Inadvertent Interchange will be retained under the WECC Regional Definitions in the Glossary of Terms Used in NERC Reliability Standards. A new definition "Automatic Timer Error Correction – ATEC" is included in this standard.

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 Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
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Document Title	WECC Standard BAL-004-WECC-02
File Name	
Category	(X) Regional Reliability Standard ( ) Regional Criterion ( ) Policy ( ) Guideline ( ) Report or other ( ) Charter
Document date	
Adopted/approved by	
Date adopted/approved	
Custodian (entity responsible for maintenance and upkeep)	
Stored/filed	Physical location: Web URL:
Previous name/number	(if any)
Status	( ) in effect ( ) usable, minor formatting/editing required ( ) modification needed ( ) superseded by _____ ( ) other _____ ( ) obsolete/archived)

Version Control

Version	Date	Action	Change Highlights
1	4/15/2011	Version 1 Posted	Addressed FERC Order 723
2		Version 2 Posted 11/4/11	Addressed comments from Version 1 posting
3		Version 3 Posted 12/15/11	Addressed comments from Version 2 posting
4		Standing Committee Approval	
5		WECC Board Approval	

WECC 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.

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Development Steps Completed:

Completed Actions	Completion Date
1. Request received	09/26/2009
2. Requested deemed Complete/Valid/Team Site created	10/06/2009
3. Pre-SRRC announcement	10/16/2009
4. SRRC notified	10/26/2009
5. SRRC assigned the Request to Standing Committee 6. Due to lack of manpower/resources this Request was placed on hold until July 2010 by Mr. Don Watkins, OC chair	11/2009
7. Assigned to the Performance Work Group by Mr. Hulls, incoming OC chair	07/16/2010
8. Drafting team (DT) announced / notice sent to DT members	07/16/2010
9. Notice of development / first 30-day notice	09/2/2010
10. New committee chair orientation meeting	08/18/2010
11. First DT meeting	11/10/2010
12. Notice of Concurrence sent by DT (see step 3) 13. New meeting announcement / also included in first meeting minutes	11/10/2010
14. DT meetings completed	12/15/10 01/18/11 02/10/11 03/11–12/11 03/24/11 04/11/11
15. Complete first draft and Complete Quality Control Checklist	04/13/2011
16. Post first draft for 45-day comment period	04/15/2011
17. Meet to answer to comments, address impact statement and draft responses	06/2-3/2011 06/14/2011 06/23/2011 06/29/2011
18. Post responses to comments received during 45-day comment period	06/29/2011
19. Meet to answer to comments, address impact statement and	08/8/2011 08/15/2011

Completed Actions	Completion Date
draft responses	08/30/2011 11/01/2011
20. Post the Version 2 for a 30-day comment period	11/04/2011
21. Post consideration of comments of Version 2	12/15/2011
22. Post the third dart for 30-day comment period	12/15/2011
23. Project WECC-0068 Version 3 Comments were due	01/16/2012
24. Meeting to answer comments, address impact statement, draft responses	01/18/2012
25. Post responses to comments	02/13/2012
26. Post for Operating Committee approval	02/24/2012

Description of Current Draft:

On May 21, 2009, the Federal Energy Regulatory Commission (Commission or FERC) issued a Final Rule approving WECC Regional Reliability Standard BAL-004-WECC-1 – Automatic Time Error Correction (BAL-004-WECC-1) and directing WECC to make several clarifying modifications to the standard using the FERC-approved Process for Developing and Approving WECC Standards.[1] In addition, WECC staff identified additional modifications to BAL-004-WECC-1 that would clarify the intent without changing the requirements. Finally, the industry has commented that there is confusion concerning BAL-004-WECC-1 Requirement R3 that requires that the Area Control Error (ACE) equation used for North American Electric Reliability Corporation (NERC) reports shall be the same ACE equation as that used during Automatic Generation Control (AGC) mode. This seems to conflict with NERC's comments in response to the Notice of Proposed Rulemaking regarding the interpretation of NERC Reliability Standard BAL-001-0.1a – Real Power Balancing Control Performance (BAL-001-0.1a) [2] wherein NERC stated that entities may use an Automatic Time Error Correction (ATEC) ACE equation for control but should use raw ACE for CPS reporting.[3] As part of this filing WECC has submitted a proposed regional variance to BAL-001-0.1a to address this conflict.

The purpose of the refinements to BAL-004-WECC-1 as proposed in WECC Regional Reliability Standard BAL-004-WECC-2 – Automatic Time Error Correction (BAL-004-WECC-2) is to implement the directives in FERC Order 723 and to make other clarifications to BAL-004-WECC-1 as the industry deems necessary, while maintaining the Western Interconnection's

[1] *Western Electricity Coordinating Council Regional Reliability Standard Regarding Automatic Time Error Correction*, Order No. 723, 127 FERC Stats. & Regs. ¶ 61,176, 74 Fed. Reg. ¶ 25,422 (2009) (hereafter Order 723).

[2] *Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards*, Notice of Proposed Rulemaking, 123 FERC Stats. & Regs. ¶ 61,064, 73 Fed. Reg. ¶ 22,856 (2008).

[3] *Comments of the North American Electric Reliability Corporation on the Notice of Proposed Rulemaking regarding Interchange and Transmission Loading Relief under RM08-7*, pgs 9-10, FERC Docket No. RM08-7-000, filed June 12, 2008.

reliability. The FERC Order 723 directives are as follows:

1. "The Commission is concerned that the phrases 'large accumulation' and 'in such a situation' as used in Requirement R1.2 leaves to individual interpretation when a 'large' amount of primary inadvertent has accumulated. The ERO and WECC agree that the provision could benefit from further clarity. Accordingly, the Commission adopts its NOPR proposal and directs WECC to develop revisions to the provision so that a balancing authority will know with specificity the circumstances that trigger the actions required by Requirement R1.2."[4]
2. "Consistent with the NOPR, pursuant to section 215(d) (5) of the FPA, the Commission directs WECC to develop a modification to the regional Reliability Standard consistent with WECC's and NERC's explanation that the limit set forth in Requirement 2 of '24 hours per calendar quarter' is an accumulated total for the period, resulting from either a singular event or a cumulative time limit from a number of events."[5]
3. "[The Commission] direct[s] that the violation risk factors assigned to BAL-004-WECC-01, Requirements R1, R2, R3, and R4 be modified from 'lower' to 'medium.' The ERO and WECC must submit a filing within 60 days of the effective date of this Final Rule that includes the directed modifications."[6] These modifications were addressed in a compliance filing dated August 28, 2009. [7]
4. "The Commission adopts its NOPR proposal and directs the ERO and WECC to submit violation severity levels for each Requirement and sub-Requirement that has been assigned a violation risk factor. To allow adequate time for the development of the violation severity levels, the ERO and WECC must submit a filing within 120 days of the effective date of this Final Rule that includes the directed violation severity levels."[8] These modifications were addressed in a compliance filing date October 23, 2009.[9]
5. In response to Xcel comments, FERC referenced their approval, in Order No. 713, of an ERO interpretation stating that as long as Balancing Authorities use raw ACE for Control Performance Standard (CPS) reporting purposes and WECC ATEC (ATEC) ACE for control, it is not a violation of BAL-001-0.1a, Requirement 1.[10]. WECC Stakeholders believe it is more appropriate to use the ATEC ACE for control and CPS reporting. To clarify this difference, WECC has developed a regional variance BAL-001-0.1a.

The implementation of an ATEC ACE is part of a regional variance to BAL-001-0.1a associated with this posting. The purpose of this filing is to meet the directives of FERC Order 723 while refining for clarity the existing requirements of BAL-004-WECC-1. Refinements to BAL-004-WECC-1 include:

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[4] Order 723 at ¶ 30.

[5] *Id* at ¶ 34.

[6] *Id* at ¶ 51.

[7] Compliance Filing of the North American Electric Reliability Corporation in response to Paragraphs 26 and 51 of Order No. 723 – Directed Modification of Violation Risk Factors for Regional Reliability Standard BAL-004-WECC-1, Automatic Time Error Correction, Docket No. RM08-12-000, filed August 28, 2009

[8] Order 723 at ¶ 54.

[9] Compliance Filing of the North American Electric Reliability Corporation in response to Paragraphs 26 and 54 of Order No. 723, Docket No. RM08-12-000, filed October 23, 2009

[10] Order 723 at ¶ 44-45.

1. A requirement that defines the large accumulation at 150% of previous year's peak demand or peak generation for generation-only Balancing Authorities. The action required is that the Balancing Authority shall not permit the PII_{accum} to exceed the defined value, which is demonstrated at the end of each month.
2. A clarification in response to the FERC order that the accumulated time for ATEC out of service shall not exceed 24 hours during a calendar quarter.

BAL-004-WECC-2 retains the requirement for Balancing Authorities to compute the Automatic Time Error Correction and Primary Inadvertent Interchange by 50 minutes after the hour and requires that Balancing Authorities have the ability to operate their Automatic Generation Control in other modes. In addition, Balancing Authorities are required to recalculate Primary Inadvertent Interchange when hourly and month-end adjustments are made.

In Version 3 in order to prevent the stranding of Secondary Inadvertent Interchange the drafting team added a Requirement R8 that restrictions the payback of Inadvertent Interchange to using ATEC rather than through bilateral and unilateral payback methods.

The proposed BAL-004-WECC-2 will replace the Automatic Time Error Correction definition in the NERC Glossary of Terms in the WECC Regional Definitions section. The WECC definitions for Primary Inadvertent Interchange and Secondary Inadvertent Interchange will be retained under the WECC Regional Definitions in the *Glossary of Terms Used in NERC Reliability Standards*.

Development Plan:

Anticipated Actions	Anticipated Date
1. Post draft standard for 45-day NERC comment period	02/01/2012
2. NERC comment period ends	03/27/2012
3. Operating Committee approves proposed standard	03/27/2012
4. DT completes review and consideration of industry comments to NERC posting	04/27/2012
5. Post draft standard for WECC Board approval	05/01/2012
6. WECC Board approval	06/21/2012
7. Post draft standard for 15-day NERC comment period	06/25/2012
8. NERC 15-day comment period ends	07/2012
9. DT completes review and consideration of industry comments to NERC posting	07/2012
10. Submit NERC Board of Trustees approval request	08/2012
11. Receive NERC Board approval	08/2012

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Implementation Plan

The Implementation Plan is to make the WECC Regional Variance to BAL-001-0.1a and BAL-004-WECC-2 effective on the first day of the second quarter, after regulatory approval in areas where applicable. Since entities are already controlling their Balancing Authority Area with the ATEC ACE equation – but are reporting using the NERC raw ACE equation for reporting CPS1 – the transition to controlling and reporting using the ATEC ACE should be minimal. Additionally, it should not take much time to implement the limits to a Balancing Authority's Accumulated Primary Inadvertent Interchange.

Definitions of Terms Used in Regional Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the NERC Glossary under WECC Regional Definitions. In addition the current definitions for "**Primary Inadvertent Interchange**" and "**Secondary Inadvertent Interchange"** will be retained in the Glossary of Terms Used in NERC Reliability Standards under WECC Regional Definitions.*

Automatic Time Error Correction: The addition of a component to the ACE equation that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error.

A. Introduction

1. Title: **Automatic Time Error Correction**

2. Number: BAL-004-WECC-02

3. Purpose: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the Interconnection.

4. Applicability

4.1. Functional Entities

4.1.1 Balancing Authorities that operate synchronously in the Western Interconnection.

5. Effective Date: On the first day of the second quarter, after applicable regulatory approval has been received (or the Reliability Standard otherwise becomes effective the first day of the fourth quarter following NERC Board adoption where regulatory approval is not required).

6. Background:

In February 2003, the WECC Automatic Time Error Correction (ATEC) Procedure (Procedure) became effective for all Balancing Authorities in the Western Interconnection. The original intent of the Procedure was to minimize the number of Manual Time Error Corrections in the Western Interconnection. ATEC provides the added benefit of a superior approach over the current NERC Reliability Standard BAL-004-0 – Time Error Correction for assigning costs and providing for the equitable payback of Inadvertent Interchange. In October 2006, the Procedure became a WECC Criterion. In May 2009, FERC issued Order No.723 that approved Regional Reliability Standard BAL-004-WECC-1 - Automatic Time Error Correction, as submitted by NERC. In addition, the Commission directed WECC to develop several clarifying modifications to BAL-004-WECC-1 using the FERC-approved Process for Developing and Approving WECC Standards. The Effective Date of the BAL-004-WECC-1 standard was July 1, 2009. BAL-004-WECC-1 required Balancing Authorities within the Western Interconnection to maintain Interconnection frequency within a predefined frequency profile and to ensure that Time Error Corrections were effectively conducted in a manner that did not adversely affect the reliability of the Interconnection. In September 2009, WECC received WECC Standards/Regional Criterion Request Form (Request) WECC-0068, which was a request for modification of BAL-004-WECC-1. In July 2010, the chair of the WECC Operating Committee assigned the Request to the Performance Work Group (PWG) for development.

B. Requirements and Measures

R1. Following the conclusion of each month each Balancing Authority shall verify that the absolute value of its Accumulated Primary Inadvertent Interchange (PII_{accum}) for both the monthly On-Peak period and the monthly Off-Peak period are each individually less than or equal to:

1.1. For load-serving Balancing Authorities, 150% of the previous calendar year's integrated hourly Peak Demand,

1.2. For generation-only Balancing Authorities, 150% of the previous calendar year's integrated hourly peak generation.

[Violation Risk Factor Medium:] [Time Horizon: Operations Assessment]

M1. Forms of acceptable evidence of compliance with Requirement R1include but are not limited to any one of the following:

- Data, screen shots from the WECC Interchange Tool (WIT),
- Data, screen shots from the internal Balancing Authority tool, or
- Production of data from any other databases, spreadsheets, displays.

R2. Each Balancing Authority shall, upon discovery of an error in the calculation of PII_{hourly}, recalculate within 90 days, the value of PII_{hourly} and adjust the PII_{accum} from the time of the error. *[Violation Risk*

Rationale for R1:

Premise: Each Balancing Authority should ensure that the absolute value of its PII_{accum} for both the On-Peak period and the Off-Peak period each individually does not exceed 150% of the previous year's Peak Demand for load-serving Balancing Authorities and 150% of the previous year's peak generation for generation-only Balancing Authorities. The Balancing Authority is required to take action to keep each PII_{accum} period within the limit. For example, the Balancing Authorities actions may include:

- Identifying and correcting the source of any metering or accounting error(s) and recalculating the hourly Primary Inadvertent Interchange **(**PII_{hourly}) and the PII_{accum} from the time of the error;
- Validating the implementation of ATEC; or
- Setting L_{max} equal to $L_{10.}$until the PII_{accum} is below the limit in Requirement R1.

Justification: PII_{accum} may grow from month-end adjustments and metering errors, even with the inclusion of I_{ATEC} in the ACE equation.

Goal: To limit the amount of PII_{accum} that a Balancing Authority can have at the end of each month.

Rationale for R2:

Premise: When a Balancing Authority finds an error in the calculation of its PII, the Balancing Authority needs time to correct the error and recalculate PII and PII_{accum}.

Justification: The drafting team selected 90 days as a reasonable amount of time to correct an error and recalculate PII and $PII_{accum,}$ since recalculation of PII and PII_{accum} is not a real-time operations reliability issue.

Goal: To promote the timely correction of errors in the calculation of PII and PII_{accum}.

Factor: Medium] [Time Horizon: Operations Assessment]

M2. Forms of acceptable evidence of compliance with Requirement R2 include but are not limited to any one of the following:

- Data, screen shots from the WIT,
- Data, screen shots from the internal Balancing Authority tool, or
- Production of data from any other databases, spreadsheets, displays.

R3. Each Balancing Authority shall keep its Automatic Time Error Correction (ATEC) in service, with an allowable exception period of less than or equal to an accumulated 24 hours per calendar quarter for ATEC to be out of service. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

M3. Forms of acceptable evidence of compliance with Requirement R3 may include, but are not limited to:

- Dated archived files,
- Historical data,
- Other data that demonstrates the ATEC was out of service for less than 24 hours per calendar quarter.

Rationale for R3:

Premise: When a Balancing Authority is not participating in ATEC, payback of PII_{accum} is delayed.

Justification: The limit of 24 hours per quarter discourages a Balancing Authority from withdrawing ATEC participation, for example, for economic gain during selected hours. If the limits were increased to 60 hours, a Balancing Authority could technically withdraw ATEC participation for one hour from Monday to Friday.

Goal: To promote fair and timely payback of PII_{accum} balances.

R4. Each Balancing Authority shall compute the following by 50 minutes after each hour:

- **4.1.** $PII_{\mathbf{hourly}}$,
- **4.2.** PII_{accum},
- **4.3.** Automatic Time Error Correction term (I_{ATEC}).

Rationale for R4:

Premise: $PII_{\mathbf{hourly}}$, PII_{accum}, and I_{ATEC} should be determined before the next scheduling hour begins.

Justification: To promote timely calculations 50 minutes was selected because it is before the next hour ramp begins and permits time to collect the data and resolve interchange metering values.

Goal: To promote the timely calculation of $PII_{\mathbf{hourly}}$, PII_{accum}, and I_{ATEC}.

[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]

M4. Forms of acceptable evidence of compliance with Requirement R4 include but are not limited to any one of the following:

- Data, screen shots from the WECC Interchange Tool that demonstrate compliance,
- Data, screen shots from internal Balancing Authority tool that demonstrate compliance, or
- Data from any other databases, spreadsheets, displays that demonstrate compliance.

R5. Each Balancing Authority shall be able to change its Automatic Generation Control operating mode between Flat Frequency (for blackout restoration); Flat Tie Line (for loss of frequency telemetry); Tie Line Bias; and Tie Line Bias plus Time Error Control (used in ATEC mode), to correspond to current operating conditions. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M5. Forms of acceptable evidence of compliance with Requirement R5 include but are not limited to any one of the following:

- Screen shots from Energy Management System,
- Demonstration using an off-line system.

Rationale for R5:

Premise: The ACE equation, and hence the AGC mode, will contain any number of parameters based on system operating conditions. Various AGC modes are identified corresponding to those operating conditions, as well as the specific sets of parameters included in the ACE equation.

Justification: Changing to the proper operating mode, corresponding to current operating conditions, affords proper movement of generating units in response to those conditions. The addition of the ATEC term results in an additional AGC mode and a different set of parameters. The inability to correctly calculate the ATEC term would dictate that AGC not be operated in the ATEC mode.

Goal: To set the AGC mode and calculate ACE in a manner that corresponds to the system operating conditions and to accommodate changes in those conditions.

R6. Each Balancing Authority shall recalculate the PII_{hourly} and PII_{accum} for the On-Peak and Off-Peak periods whenever adjustments are made to hourly Inadvertent Interchange or ΔTE. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M6. Forms of acceptable evidence of compliance with Requirement R6 include but are not limited to any one of the following:

Rationale for R6:

Premise: Hourly adjustments to hourly Inadvertent Interchange (II) require a recalculation of the corresponding hourly PII value, the corresponding PII_{accum}, and all subsequent PII_{accum} for every hour up to the current hour.

Justification: As $PII_{\mathbf{hourly}}$ is corrected, then PII_{accum} should be recalculated.

Goal: To promote accurate, fair and timely payback of accumulated PII balances.

- Data, screen shots from the WECC Interchange Tool that demonstrate compliance,
- Data, screen shots from an internal Balancing Authority tool that demonstrate compliance with, or
- Data from any other databases, spreadsheets, displays that demonstrate compliance.

R7. Each Balancing Authority shall make the same adjustment to the PII_{accum} as it did for any month-end meter reading adjustments to Inadvertent Interchange. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M7. Forms of acceptable evidence of compliance with Requirement R7 include but are not limited to any one of the following:

- Data, screen shots from the WECC Interchange Tool that demonstrate compliance,
- Data, screen shots from an internal Balancing Authority tool that demonstrate compliance,
- Production of data from any other databases, spreadsheets, displays that demonstrate compliance.

Rationale R7:

Premise: Month-end meter-reading adjustments are made, for example, when a Balancing Authority performs monthly comparisons of recorded month-end Net Actual Interchange (NI_A) values derived from hourly Actual Interchange Telemetered Values against month-end Actual Interchange Register Meter readings.

Justification: Month-end adjustments to II_{accum} are applied as 100% PII_{accum}. 100% was chosen for simplicity to bilaterally assign PII_{accum} to both Balancing Authorities, since the effect of this metering error on system frequency is not easily determined over the course of a month.

Goal: To provide a mechanism by which corresponding month-end II adjustments can be applied to PII_{accum}, when such adjustments cannot be attributed to any one particular hour or series of hours.

R8. Each Balancing Authority shall payback Inadvertent Interchange using ATEC rather than bilateral and unilateral payback. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M8. Forms of acceptable evidence of compliance with Requirement R8 include but are not limited to historical On-Peak and Off-Peak Inadvertent Interchange data, data from

Rationale R8:

Premise: ATEC includes automatic unilateral payback of Primary Inadvertent Interchange and Secondary Inadvertent Interchange.

Justification: Additional unilateral and bilateral exchanges disturb the balance and distribution between Primary Inadvertent Interchange and Secondary Inadvertent Interchange throughout the Interconnection; thereby stranding Secondary Inadvertent Interchange.

Goal: To not strand Secondary Inadvertent Interchange.

the WECC Interchange Tool, and ACE data.

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority.

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2 Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.3 Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority in the Western Interconnection shall retain the values of PII_{hourly}, PII_{accum} (On-Peak and Off-Peak), ΔTE and any month-end adjustments for the preceding calendar year (January – December), as well as the current calendar year.

Each Balancing Authority in the Western Interconnection shall retain the amount of time the Balancing Authority operated without ATEC for the preceding calendar year (January – December), as well as the current calendar year.

1.4 Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment	Medium	Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 150%, but was less than or equal to 160% of the previous calendar year's Peak Demand or peak generation for generation-only Balancing Authorities.	Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 160%, but was less than or equal to 170% of the previous calendar year's Peak Demand or peak generation for generation-only Balancing Authorities.	Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 170%, but was less than or equal to 180% of the previous calendar year's Peak Demand or peak generation for generation-only Balancing Authorities.	Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 180% of the previous calendar year's Peak Demand or peak generation for generation-only Balancing Authorities.
R2	Operations Assessment	Medium	The Balancing Authority did not recalculate PII_{hourly} and adjust the PII_{accum} within 90 days of the discovery of the error; but made the required recalculations and adjustments within 120 days.	The Balancing Authority did not recalculate PII_{hourly} and adjust the PII_{accum} within 120 days of the discovery of the error; but made the required recalculations and adjustments within 150 days.	The Balancing Authority did not recalculate PII_{hourly} and adjust the PII_{accum} within 150 days of the discovery of the error; but made the required recalculations and adjustments within 180 days.	The Balancing Authority did not recalculate PII_{hourly} and adjust PII_{accum} within 180 days of the discovery of the error.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Real-Time Operations	Medium	The Balancing Authority operated during a calendar quarter without ATEC in service for more than an accumulated 24 hours, but less than or equal to 72 hours.	The Balancing Authority operated during a calendar quarter without ATEC in service for more than an accumulated 72 hours, but less than or equal to 120 hours.	The Balancing Authority operated during a calendar quarter without ATEC in service for more than an accumulated 120 hours, but less than or equal to 168 hours	The Balancing Authority operated during a calendar quarter without ATEC in service for more than an accumulated 168 hours.
R4	Operations Assessment	Medium	The Balancing Authority did not compute PII_{hourly}, PII_{accum}, and I_{ATEC} within 50 minutes, but made the required calculations in less than or equal to two hours.	The Balancing Authority did not compute PII_{hourly}, PII_{accum}, and I_{ATEC} within two hours, but made the required calculations in less than or equal to four hours.	The Balancing Authority did not compute PII_{hourly}, PII_{accum}, and I_{ATEC} within four hours, but made the required calculations in less than or equal to six hours.	The Balancing Authority did not compute PII_{hourly}, PII_{accum}, and I_{ATEC} within six hours.
R5	Real-Time Operations	Medium	N/A	N/A	N/A	The Balancing Authority is not able to change its AGC operating mode between Flat Frequency (for blackout restoration; Flat Tie Line (for loss of frequency telemetry); Tie Line Bias; or Tie Line Bias

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						plus Time Error control (used in ATEC mode).
R6	Operations Assessment	Medium	N/A	N/A	N/A	When making adjustments to hourly Inadvertent Interchange or ΔTE, the Balancing Authority did not recalculate the PII_{hourly} and the PII_{accum} for the On-Peak and Off-Peak periods.
R7	Operations Assessment	Medium	N/A	N/A	N/A	When making any month-end meter reading adjustments to Inadvertent Interchange, the Balancing Authority did not make the same adjustment to the PII_{accum}.
R8	Operations Assessment	Medium	N/A	N/A	N/A	The Balancing Authority paid back Inadvertent Interchange using bilateral and unilateral payback rather than

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						using ATEC.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Requirement R4:

Requirement R5:

Requirement R6:

Requirement R7:

Requirement R8:

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Clarification: Regional Reliability Standards Announcement - Comment Period Open for BAL-001-0.1a (WECC Variance) | January 23 – March 9, 2012
Date: Monday, January 23, 2012 3:41:34 PM

Regional Reliability Standards Announcement

Comment Period Open for BAL-001-0.1a (WECC Variance)

January 23 – March 9, 2012 (For clarification purposes in red.)

Regional Project: Now available

Proposed Standard for the Western Electricity Coordinating Council (WECC)
WECC has requested NERC to post **WECC's proposed regional variance to NERC** standard BAL-001-0.1a Real Power Balancing Control Performance (WECC Variance) for a 45-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 Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the regional standards development page.

Background
The purpose of this proposed WECC Regional Variance to BAL-001-01.a (WECC Variance) is to replace Requirements R1 and Section D. Compliance, Subsection 2 of BAL-001-0.1a with three new requirements. In Requirement E.B.1 of the WECC Variance, the drafting team proposes to replace the NERC ACE equation with an ACE equation that includes the ATEC term. Replacing the NERC raw ACE equation with the ATEC ACE equation through a Regional Variance will require Balancing Authorities in the Western Interconnection to use the ATEC ACE for control and CPS reporting purposes. Using the ATEC ACE equation for CPS reporting is more appropriate because, as discussed further below, it is a more accurate measure of how well a Balancing Authority is controlling to its control performance target.

The drafting team for Project WECC-0068 also requests withdrawal of the BAL-001-0.1a Appendix 2 Interpretation of Requirement R1and the BAL-003-0.1b Appendix 1 Interpretation of Requirement R3. By creating a Regional Variance that replaces Requirement R1, these interpretations are no longer needed. The drafting team revised the definition for Area Control Error (ACE) in the WECC Regional Definitions to closely align with NERC definition for ACE while at the same recognizing concept of ATEC.

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.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Reliability Standards Announcement

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For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Document Title	WECC Regional Variance to NERC Standard BAL-001-0.1a
File Name	
Category	(X) Regional Reliability Standard ( ) Regional Criterion ( ) Policy ( ) Guideline ( ) Report or other ( ) Charter
Document date	
Adopted/approved by	
Date adopted/approved	
Custodian (entity responsible for maintenance and upkeep)	
Stored/filed	Physical location: Web URL:
Previous name/number	(if any)
Status	( ) in effect ( ) usable, minor formatting/editing required ( ) modification needed ( ) superseded by _____ ( ) other _____ ( ) obsolete/archived)

Version Control

Version	Date	Action	Change Highlights
1		Version 1 Posted 4/15/11-6/1/11	Addressed FERC Order 723
2		Version 2 Posted 11/4/11	Addressed comments from Version 1 posting
3		Version 3 Posted 12/15/11	Addressed comments from Version 2 posting
4		Standing Committee Approval	
5		WECC Board Approval	

Regional Variance 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:

Completed Actions	Completion Date
1. Request received	09/26/2009
2. Requested deemed Complete/Valid/Team Site created	10/06/2009
3. Pre-SRRC announcement	10/16/2009
4. SRRC notified	10/26/2009
5. SRRC assigned the Request to Standing Committee 6. Due to lack of manpower/resources this Request was placed on hold until July 2010 by Mr. Don Watkins, OC chair	11/2009
7. Assigned to the Performance Work Group by Mr. Hulls, incoming OC chair	07/16/2010
8. Drafting team (DT) announced / notice sent to DT members	07/16/2010
9. Notice of development / first 30-day notice	09/2/2010
10. New committee chair orientation meeting	08/18/2010
11. First DT meeting	11/10/2010
12. Notice of Concurrence sent by DT (see step 3) 13. New meeting announcement / also included in first meeting minutes	11/10/2010
14. DT meetings completed	12/15/10 01/18/11 02/10/11 03/11–12/11 03/24/11 04/11/11
15. Complete first draft and Complete Quality Control Checklist	04/13/2011
16. Post first draft for 45-day comment period	04/15/2011
17. Meeting to answer comments, address impact statement and draft responses	06/2-3/2011 06/14/2011

	06/23/2011 06/29/2011
18. Post responses to comments received during 45-day comment period	06/29/2011
19. Meet to answer to comments, address impact statement and draft responses	08/8/2011 08/15/2011 08/30/2011 11/01/2011
20. Post Version 2 for a 30-day comment period	11/04/2011
21. Post consideration of comments of Version 2	12/15/2011
22. Post Version 3 for 30-day comment period	12/15/2011
23. Project WECC-0068 Version 3 Comments were due	01/16/2012
24. Met to answer to comments, address impact statement, draft responses	01/18/2012
25. Post responses to comments	02/13/2012
26. Post for Operating Committee approval	02/24/2012

Description of Current Draft:

On May 21, 2009, the Federal Energy Regulatory Commission (Commission or FERC) issued a Final Rule approving WECC Regional Reliability Standard BAL-004-WECC-1 – Automatic Time Error Correction (BAL-004-WECC-1) and directing WECC to make several clarifying modifications to the standard using the FERC-approved Process for Developing and Approving WECC Standards.[1] Since the approval of BAL-004-WECC-1 the industry has commented that there is confusion concerning BAL-004-WECC-1 Requirement R3 that requires that the Area Control Error (ACE) equation used for North American Electric Reliability Corporation (NERC) reports shall be the same ACE equation as that used during Automatic Generation Control (AGC) mode. The use of two ACE equations came as a result of NERC's comments in response to the Notice of Proposed Rulemaking regarding the interpretation of NERC Reliability Standard BAL-001-0.1a – Real Power Balancing Control Performance (BAL-001-0.1a)[2] wherein NERC stated that entities may use an Automatic Time Error Correction (ATEC) ACE equation

[1] *Western Electricity Coordinating Council Regional Reliability Standard Regarding Automatic Time Error Correction*, Order No. 723, 127 FERC Stats. & Regs. ¶ 61,176, 74 Fed. Reg. ¶ 25,422 (2009) (hereafter Order 723).

[2] *Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards*, Notice of Proposed Rulemaking, 123 FERC Stats. & Regs. ¶ 61,064, 73 Fed. Reg. ¶ 22,856 (2008).

for control but should use raw ACE for CPS reporting.[3] The industry desires to use the same ACE equation for control and reporting because it provides better a measurement of control performance.

The purpose of this proposed WECC Regional Variance to BAL-001-01.a (WECC Variance) is to replace Requirements R1 and Section D. Compliance, Subsection 2. of BAL-001-0.1a with three new requirements. In Requirement E.B.1 of the WECC Variance, the drafting team proposes to replace the NERC ACE equation with an ACE equation that includes the ATEC term. Replacing the NERC raw ACE equation with the ATEC ACE equation through a Regional Variance will require Balancing Authorities in the Western Interconnection to use the ATEC ACE for control and CPS reporting purposes. Using the ATEC ACE equation for CPS reporting is more appropriate because, as discussed further below, it is a more accurate measure of how well a Balancing Authority is controlling to its control performance target.

The drafting team for Project WECC-0068 also requests withdrawal of the BAL-001-0.1a Appendix 2 Interpretation of Requirement R1and the BAL-003-0.1b Appendix 1 Interpretation of Requirement R3. By creating a Regional Variance that replaces Requirement R1, these interpretations are no longer needed. The drafting team revised the definition for Area Control Error (ACE) in the WECC Regional Definitions to closely align with NERC definition for ACE while at the same recognizing concept of ATEC.

In order to obtain a Regional Variance[4] to a NERC Reliability Standard, it must be demonstrated that:

- The variance is not inconsistent with or less stringent than the NERC reliability standard;
- Is necessitated by a physical difference; or
- Is an alternative methodology with the same reliability objective.

Replacing the NERC ACE equation with an ATEC ACE equation is an alternative methodology with the same reliability objective as the existing BAL-001-0.1a standard. It is a method of automatically scheduling Primary Inadvertent Interchange (PII) back to other Balancing Authorities. The inclusion of the Automatic Time Error Correction term in the ACE equation changes the Balancing Authority's control performance target. The current NERC ACE equation requires that Balancing Authorities control the frequency and Interchange within their Balancing Authority Area to a target point of zero, but it allows the control to stay within a predefined range called L_{max} which is between 0.20 * |B| and $\pm L_{10}$. The proposed ACE equation, with an Automatic Time Error adjustment, works similarly to the NERC equation; however, the target

[3] *Comments of the North American Electric Reliability Corporation on the Notice of Proposed Rulemaking regarding Interchange and Transmission Loading Relief under RM08-7*, pgs 9-10, FERC Docket No. RM08-7-000, filed June 12, 2008.

[4] "Entity variance" means an aspect of a reliability standard that applies only within a particular entity or a subset of entities within a limited portion of a regional entity, such as a variance that would apply to a regional transmission organization or particular market or to a subset of bulk power system owners, operators or users. An entity variance may not be inconsistent with or less stringent than the reliability standards as it would otherwise exist without the entity variance. An entity variance shall be approved only through the NERC standards development procedure and shall be made part of the NERC reliability standards." (Rules of Procedure of the North American Electric Reliability Corporation, Section 200 — Definition of Terms, page 2.)

point for control is adjusted by the ATEC adjustment. The ATEC component defines a new control point and is equivalent to making an interchange schedule that would automatically payback PII. The modification to the ACE equation is equivalent to making an adjustment because of a metering error. Since the amount of the adjustment during any one hour is limited by L_{max1}, Balancing Authorities automatically limit the risk to the interconnection and the amount of the transaction.

The addition of the I_{ATEC} component meets the standard of justification for a Regional Variance as an alternative methodology, with the same reliability objective as the NERC Reliability Standard. In addition, the proposed WECC variance to BAL-001-0.1a is consistent with — or more stringent than — the NERC BAL-001-0.1a Reliability Standard. The reasons the WECC Variance meets the standard of justification are:

1. The addition of I_{ATEC} to the ACE equation and adjustment to the control performance target used for controlling frequency and interchange does not place any addition risk to reliability because limits are set in the magnitude of the I_{ATEC} adjustment.
2. The Regional Variance allows the use of the same control performance target for control and reporting providing a better methodology for measuring performance.
3. It is another control methodology that achieves the same reliability objective as BAL-001-0.1a.

BAL-004-WECC-1 requires Balancing Authorities in the Western Interconnection to use ATEC ACE for control. As proposed in the WECC Variance, Balancing Authorities in the Western Interconnection are required to operate synchronously to the Interconnection, using the ATEC ACE, which automatically corrects time error. The ATEC component in the ACE equation has been effective in mitigating two main issues in the Western Interconnection.

1. It has been used to reduce the number of hours of Manual Time Error Corrections, or the amount of manual adjustments of timing errors that accumulate on clocks, which make certain interconnection scheduled frequency deviations.
2. Since time error is directly related to Inadvertent Interchange, the procedure has been used to reduce accumulated Inadvertent Interchange, or the difference between the actual and scheduled interchange.

The ATEC procedure requires Balancing Authorities in the Western Interconnection to determine their contribution to the Interconnection time error. The Balancing Authority does this by calculating its PII. BAL-001-0.1a Requirement E.B.1 requires that each Balancing Authority calculate its PII_{accum} and I_{ATEC} from its hourly Inadvertent Interchange. When the resulting I_{ATEC} is entered into Balancing Authority's ACE equation, I_{ATEC} continuously corrects for its portion of the time error automatically, as opposed to manually, as specified in the continent-wide standard on Time Error Correction BAL-004-1 Requirement R2. Although the maximum payback is bounded between limits, the continuous correction enables equitable payback of Primary Inadvertent Interchange.

The drafting team is proposing the same Violation Severity Levels for Requirement R1 of the WECC Variance as those in Requirement R1 of BAL-001-01.a because it is a measurement of how well a Balancing Authority is controlling to its control performance target.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post draft standard for 45-day NERC comment period	02/01/2012
2. NERC comment period ends	03/27/2012
3. Operating Committee approves proposed standard	03/27/2012
4. DT completes review and consideration of industry comments to NERC posting	04/27/2012
5. Post draft standard for WECC Board approval	05/01/2012
6. WECC Board approval	06/21/2012
7. Post draft standard for 15-day NERC comment period	06/25/2012
8. NERC 15-day comment period ends	07/2012
9. DT completes review and consideration of industry comments to NERC posting	07/2012
10. Submit NERC Board of Trustees approval request	08/2012
11. Receive NERC Board approval	08/2012

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Implementation Plan

The proposed Implementation Plan is to make the WECC Regional Variance to BAL-001-0.1a and the proposed WECC Regional Reliability Standard BAL-004-WECC-2 effective on the first day of the second quarter, after regulatory approval. Since entities are already controlling with the ATEC ACE equation, but are using the NERC raw ACE equation for purposes of reporting CPS1, the transition to controlling and reporting using the ATEC ACE should be minimal. Additionally, it should not require much time to implement the limits to a Balancing Authority's Accumulated Primary Inadvertent Interchange.

Definitions of Terms Used in Regional Variance to a NERC Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the NERC Glossary under WECC Regional Definitions.

Area Control Error: The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection.

A. Introduction

1. **Title**: **Real Power Balancing Control Performance**

2. **Number**: BAL-001-0.1a

3. **Purpose**: To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.

4. **Applicability**:

   4.1. Balancing Authorities

~~5. **Effective Date:** May 13, 2009~~

5. **Effective Date:** The WECC Regional Variance to NERC Reliability Standard BAL-001-0.1a is to be effective on the first day of the second quarter, after regulatory approval.

B. Requirements

R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε_1^2 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \le \in_1^2 \; or \; \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\in_1^2} \le 1$$

Committee.

The equation for ACE is:

$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$

where:

- NI_A is the algebraic sum of actual flows on all tie lines.
- NI_S is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections.
- I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

R2. Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}.

$$AVG_{10-\text{minute}}(ACE_i) \le L_{10}$$

where:

$L_{10}=1.65 \in_{10} \sqrt{(-10B_i)(-10B_s)}$

ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.

R3. Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.

R4. Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance perspective, the Balancing Authority has shifted all control requirements to the Balancing Authority providing Overlap Regulation Service).

C. Measures

M1. Each Balancing Authority shall achieve, as a minimum, Requirement 1 (CPS1) compliance of 100%.

CPS1 is calculated by converting a compliance ratio to a compliance percentage as follows:

CPS1 = (2 - CF) * 100%

The frequency-related compliance factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the target frequency bound:

$$CF = \frac{CF_{12-\text{month}}}{(\in_1)^2}$$

where: ε_1 is defined in Requirement R1.

The rating index $CF_{12\text{-month}}$ is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, Frequency Error and Frequency Bias Settings.

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for ACE and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\frac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}\right)}{\text{-10B}}$$

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority's clock-minute compliance factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}}\right]$$

Normally, sixty (60) clock-minute averages of the reporting Balancing Authority's ACE and of the respective Interconnection's Frequency Error will be used to compute the respective hourly average compliance parameter.

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$\text{CF}_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(\text{CF}_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]}$$

$$\text{CF}_{\text{month}} = \frac{\sum_{\text{hours-in-day}} [(\text{CF}_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}} [n_{\text{one-minute samples in clock-hour averages}}]}$$

The 12-month compliance factor becomes:

$$\text{CF}_{\text{12-month}} = \frac{\sum_{\text{i=1}}^{12} (CF_{\text{month-i}})(n_{(\text{one-minute samples in month})-\text{i}})]}{\sum_{\text{i=1}}^{12} [n_{(\text{one-minute samples in month})\text{-i}}]}$$

In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and Frequency Deviation samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or Frequency Deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and Frequency Deviation, that one-minute interval shall be excluded from the calculation of CPS1.

M2. Each Balancing Authority shall achieve, as a minimum, Requirement R2 (CPS2) compliance of 90%. CPS2 relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

$$CPS2 = \left[1 - \frac{\text{Violations}_{\text{month}}}{\left(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}}\right)}\right] * 100$$

The violations per month are a count of the number of periods that ACE clock-ten-minutes exceeded L_{10}. ACE clock-ten-minutes is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.

Violation clock-ten-minutes

= 0 if

$$\left|\frac{\sum ACE}{n_{\text{samples in 10-minutes}}}\right| \leq L_{10}$$

= 1 if

$$\left|\frac{\sum ACE}{n_{\text{samples in 10-minutes}}}\right| > L_{10}$$

Each Balancing Authority shall report the total number of violations and unavailable periods for the month. L_{10} is defined in Requirement R2.

Since CPS2 requires that ACE be averaged over a discrete time period, the same factors that limit total periods per month will limit violations per month. The calculation of total periods per month and violations per month, therefore, must be discussed jointly.

A condition may arise which may impact the normal calculation of total periods per month and violations per month. This condition is a sustained interruption in the recording of ACE.

In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples are present for that interval. Should half or more of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval shall be omitted from the calculation of CPS2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization~~.~~

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar month.

1.3. Data Retention

The data that supports the calculation of CPS1 and CPS2 (Appendix 1-BAL-001-0) are to be retained in electronic form for at least a one-year period. If the CPS1 and CPS2 data for a Balancing Authority Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved. Each Balancing Authority shall retain for a rolling 12-month period the values of: one-minute average ACE (ACE_i), one-minute average Frequency Error, and, if using variable bias, one-minute average Frequency Bias.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance – CPS1

2.1. Level 1: The Balancing Authority Area's value of CPS1 is less than 100% but greater than or equal to 95%.

2.2. Level 2: The Balancing Authority Area's value of CPS1 is less than 95% but greater than or equal to 90%.

2.3. Level 3: The Balancing Authority Area's value of CPS1 is less than 90% but greater than or equal to 85%.

2.4. Level 4: The Balancing Authority Area's value of CPS1 is less than 85%.

3. Levels of Non-Compliance – CPS2

3.1. Level 1: The Balancing Authority Area's value of CPS2 is less than 90% but greater than or equal to 85%.

3.2. Level 2: The Balancing Authority Area's value of CPS2 is less than 85% but greater than or equal to 80%.

3.3. Level 3: The Balancing Authority Area's value of CPS2 is less than 80% but greater than or equal to 75%.

3.4. Level 4: The Balancing Authority Area's value of CPS2 is less than 75%.

E. Regional ~~Differences~~Variances

~~1.~~**E.A.** The ERCOT Control Performance Standard 2 Waiver approved November 21, 2002.

E.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Interconnection and replaces, in their entirety, Requirement R1 and Section D.2.

(i.e., under Compliance replace Levels of Non-Compliance – CPS1). Please note that the ACE equation is replaced in its entirety with the following equation identified in Requirement E.B.1.

Requirements and Measures

E.B.1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit $\in_1^2$ is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \le \in_1^2 \; or \; \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\in_1^2} \le 1$$

The equation for ACE in the Western Interconnection is:

$$ACE = (NI_A - NI_S) - 10B(F_A - F_S) - I_{ME} + I_{ATEC}$$

Where:

NI_A is the algebraic sum of actual flows on all tie lines.

NI_S is the algebraic sum of scheduled flows on all tie lines.

F_A is the actual frequency.

F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections.

B = Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.

I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line

Rationale for E.B.1

Premise: When a Balancing Authority Area uses the ACE equation with an ATEC correction component for both control and assessing performance, it provides a more accurate measurement of the Control Performance methodology while at the same time achieving the same reliability objective as the existing BAL-001-0.1a standard.

Justification: Adding the ***I_{ATEC}*** term to the ACE equation reduces the number of manual time error corrections and PII_{accum}.

Goal: To establish an ACE equation that permits the implementation of Automatic Time Error Correction.

flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

$$I_{ATEC} = \frac{PII_{accum}^{on/off\ peak}}{(1-Y)*H}$$ when operating in Automatic Time Error Correction control mode.

I_{ATEC} shall be zero when operating in any other AGC mode.

Y = B / B_S.

H = Number of Hours used to payback Primary Inadvertent Interchange energy. The value of H is set to 3.

B_S = Frequency Bias for the Interconnection (MW / 0.1 Hz).

Primary **I**nadvertent **I**nterchange **(PII_{hourly})** is **$(1-Y) * (II_{actual} - B * \Delta TE/6)$**

II_{actual} is the hourly Inadvertent Interchange for the last hour.

ΔTE is the hourly change in system Time Error as distributed by the Interconnection Time Monitor. Where:

$\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$

TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection Time Monitor control center clocks.

t is the number of minutes of Manual Time Error Correction that occurred during the hour.

TE_{offset} is 0.000 or +0.020 or -0.020.

PII_{accum} is the Balancing Authority's accumulated **PII_{hourly}** in MWh. An On-Peak and Off-Peak accumulation accounting is required.

Where:

$PII_{accum}^{on/off\ peak}$ **= last period's** $PII_{accum}^{on/off\ peak}$ **+** PII_{hourly}

[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

M.E.B.1. Each Balancing Authority shall achieve, as a minimum, Requirement E.B.1 (CPS1) compliance of 100%.

CPS1 is calculated by converting a compliance ratio to a compliance percentage as follows:

CPS1 = (2 - CF) * 100%

The frequency-related compliance factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the target frequency bound:

$$CF = \frac{CF_{12-\text{month}}}{(\epsilon_1)^2}$$

where: ϵ_1 is defined in Requirement E.B.1.

The rating index $CF_{12\text{-month}}$ is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, Frequency Error and Frequency Bias Settings.

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for ACE and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\frac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}\right)}{-10\text{B}}$$

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority's clock-minute compliance factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}}\right]$$

Normally, sixty (60) clock-minute averages of the reporting Balancing Authority's ACE and of the respective Interconnection's Frequency Error are used to compute the respective hourly average compliance parameter.

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

As part of its evidence each Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$\text{CF}_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(\text{CF}_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]}$$

$$CF_{month} = \frac{\sum_{hours\text{-}in\text{-}day}[(CF_{clock\text{-}hour\ average\text{-}month})(n_{one\text{-}minute\ samples\ in\ clock\text{-}hour\ averages})]}{\sum_{hours\text{-}in\ day}[n_{one\text{-}minute\ samples\ in\ clock\text{-}hour\ averages}]}$$

The 12-month compliance factor becomes:

$$CF_{12\text{-}month} = \frac{\sum_{i=1}^{12}(CF_{month\text{-}i})(n_{(one\text{-}minute\ samples\ in\ month)-i})]}{\sum_{i=1}^{12}[n_{(one\text{-}minute\ samples\ in\ month)\text{-}i}]}$$

In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and Frequency Deviation samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or Frequency Deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and Frequency Deviation, that one-minute interval shall be excluded from the calculation of CPS1.

E.B.2. Each Balancing Authority shall limit the absolute value of I_{ATEC}, the Automatic Time Error Correction term as follows: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

$$|I_{ATEC}| \leq L_{max}.$$

Rationale for E.B.2

Premise: I_{ATEC} greater than L_{max} may result in a risk to reliability caused by large ATEC payback.

Justification: Balancing Authorities should not control their Balancing Authority Areas using an approach that puts system reliability at risk.

Goal: The goal of Requirement E.B.2 is to limit I_{ATEC} to L_{max} in order to reduce potential reliability risks to the interconnection caused by a large ATEC payback term.

M.E.B.2. Forms of acceptable evidence for Requirement E.B. 2 may include, but are not limited to:

- Dated Energy Management System (EMS) displays,
- WECC Interchange Tool, EMS application code, or

Rationale for E.B.3

Premise: Operating within an L_{max} less than 0.20 * |B| may not provide sufficient correction for PII and operating with an L_{max} greater than L_{10} may result in potential reliability risks caused by a large ATEC payback term.

Justification: L_{max} should be limited to prevent Balancing Authorities from creating potential reliability risks caused by a large ATEC payback term.

Goal: The goal of Requirement E.B.3 is to develop a range for L_{max} where Balancing Authorities reduce potential reliability risks by limiting I_{ATEC} to L_{max}.

- Other archived data that demonstrates compliance.

E.B.3. Each Balancing Authority shall set L_{max} within the limits as follows:

$$0.20 * |B| \leq L_{max} \leq L_{10}.$$

[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

M.E.B.3. Forms of acceptable evidence for Requirement E.B. 3 may include, but is not limited to:

- Dated Energy Management System (EMS) displays,
- WECC Interchange Tool, EMS application code, or
- Other archived data that demonstrates compliance.

E.B. Compliance

1. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority in the Western Interconnection shall retain the values of I_{ATEC} and L_{max} for the preceding calendar year (January – December), as well as the current calendar year.

Table of Compliance Elements

E #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
E.B.1	Real-time Operations	Medium	The Balancing Authority Area's value of CPS1 was less than 100% but greater than or equal to 95%.	The Balancing Authority Area's value of CPS1 was less than 95% but greater than or equal to 90%.	The Balancing Authority Area's value of CPS1 was less than 90% but greater than or equal to 85%.	The Balancing Authority Area's value of CPS1 was less than 85%.
E.B.2	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority Area's absolute value for I_{ATEC} was greater than L_{max}.
E.B.3	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority did not set L_{max} to within the limits in E.B.3 (i.e., $0.20 * \|B\| \leq L_{max} \leq L_{10}$).

F. Associated Documents

E.A. Appendix 2 — Interpretation of Requirement R1 (October 23, 2007).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	Revised
0a	January 16, 2008	In Section A.2., Added "a" to end of standard number In Section F, corrected automatic numbering from "2" to "1" and removed "approved" and added parenthesis to "(October 23, 2007)"	Errata
0	January 23, 2008	Reversed errata change from July 24, 2007	Errata
0.1a	October 29, 2008	Board approved errata changes; updated version number to "0.1a"	Errata
0.1a	May 13, 2009	Approved by FERC	
		WECC Regional Variance Retirement of Appendix 2 Interpretation of Requirement R1	

Appendix 1-BAL-001-0
CPS1 and CPS2 Data

CPS1 DATA	Description	Retention Requirements
ε_1	A constant derived from the targeted frequency bound. This number is the same for each Balancing Authority Area in the Interconnection.	Retain the value of ε_1 used in CPS1 calculation.
ACE_i	The clock-minute average of ACE.	Retain the 1-minute average values of ACE (525,600 values).
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value(s) of B_i used in the CPS1 calculation.
F_A	The actual measured frequency.	Retain the 1-minute average frequency values (525,600 values).
F_S	Scheduled frequency for the Interconnection.	Retain the 1-minute average frequency values (525,600 values).

CPS2 DATA	Description	Retention Requirements
V	Number of incidents per hour in which the absolute value of ACE clock-ten-minutes is greater than L_{10}.	Retain the values of V used in CPS2 calculation.
ε_{10}	A constant derived from the frequency bound. It is the same for each Balancing Authority Area within an Interconnection.	Retain the value of ε_{10} used in CPS2 calculation.
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value of B_i used in the CPS2 calculation.
B_s	The sum of Frequency Bias of the Balancing Authority Areas in the respective Interconnection. For systems with variable bias, this is equal to the sum of the minimum Frequency Bias Setting.	Retain the value of B_s used in the CPS2 calculation. Retain the 1-minute minimum bias value (525,600 values).
U	Number of unavailable ten-minute periods per hour used in calculating CPS2.	Retain the number of 10-minute unavailable periods used in calculating CPS2 for the reporting period.

Appendix 2

Interpretation of Requirement 1

Request: *Does the WECC Automatic Time Error Control Procedure (WATEC) violate Requirement 1 of BAL-001-0?*

Interpretation:
Requirement 1 of BAL-001 — Real Power Balancing Control Performance, is the definition of the area control error (ACE) equation and the limits established for Control Performance Standard 1 (CPS1).

BAL-001-0

R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε12 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

- The WATEC procedural documents ask Balancing Authorities to maintain raw ACE for CPS reporting and to control via WATEC-adjusted ACE.
- As long as Balancing Authorities use raw (unadjusted for WATEC) ACE for CPS reporting purposes, the use of WATEC for control is not in violation of BAL-001 Requirement 1.

Document Title	WECC Regional Variance to NERC Standard BAL-001-0.1a
File Name	
Category	(X) Regional Reliability Standard ( ) Regional Criterion ( ) Policy ( ) Guideline ( ) Report or other ( ) Charter
Document date	
Adopted/approved by	
Date adopted/approved	
Custodian (entity responsible for maintenance and upkeep)	
Stored/filed	Physical location: Web URL:
Previous name/number	(if any)
Status	( ) in effect ( ) usable, minor formatting/editing required ( ) modification needed ( ) superseded by _____ ( ) other _____ ( ) obsolete/archived)

Version Control

Version	Date	Action	Change Highlights
1		Version 1 Posted 4/15/11-6/1/11	Addressed FERC Order 723
2		Version 2 Posted 11/4/11	Addressed comments from Version 1 posting
3		Version 3 Posted 12/15/11	Addressed comments from Version 2 posting
4		Standing Committee Approval	
5		WECC Board Approval	

Regional Variance 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:

Completed Actions	Completion Date
1. Request received	09/26/2009
2. Requested deemed Complete/Valid/Team Site created	10/06/2009
3. Pre-SRRC announcement	10/16/2009
4. SRRC notified	10/26/2009
5. SRRC assigned the Request to Standing Committee 6. Due to lack of manpower/resources this Request was placed on hold until July 2010 by Mr. Don Watkins, OC chair	11/2009
7. Assigned to the Performance Work Group by Mr. Hulls, incoming OC chair	07/16/2010
8. Drafting team (DT) announced / notice sent to DT members	07/16/2010
9. Notice of development / first 30-day notice	09/2/2010
10. New committee chair orientation meeting	08/18/2010
11. First DT meeting	11/10/2010
12. Notice of Concurrence sent by DT (see step 3) 13. New meeting announcement / also included in first meeting minutes	11/10/2010
14. DT meetings completed	12/15/10 01/18/11 02/10/11 03/11–12/11 03/24/11 04/11/11
15. Complete first draft and Complete Quality Control Checklist	04/13/2011
16. Post first draft for 45-day comment period	04/15/2011
17. Meeting to answer comments, address impact statement and draft responses	06/2-3/2011 06/14/2011

	06/23/2011 06/29/2011
18. Post responses to comments received during 45-day comment period	06/29/2011
19. Meet to answer to comments, address impact statement and draft responses	08/8/2011 08/15/2011 08/30/2011 11/01/2011
20. Post Version 2 for a 30-day comment period	11/04/2011
21. Post consideration of comments of Version 2	12/15/2011
22. Post Version 3 for 30-day comment period	12/15/2011
23. Project WECC-0068 Version 3 Comments were due	01/16/2012
24. Met to answer to comments, address impact statement, draft responses	01/18/2012
25. Post responses to comments	02/13/2012
26. Post for Operating Committee approval	02/24/2012

Description of Current Draft:

On May 21, 2009, the Federal Energy Regulatory Commission (Commission or FERC) issued a Final Rule approving WECC Regional Reliability Standard BAL-004-WECC-1 – Automatic Time Error Correction (BAL-004-WECC-1) and directing WECC to make several clarifying modifications to the standard using the FERC-approved Process for Developing and Approving WECC Standards.[1] Since the approval of BAL-004-WECC-1 the industry has commented that there is confusion concerning BAL-004-WECC-1 Requirement R3 that requires that the Area Control Error (ACE) equation used for North American Electric Reliability Corporation (NERC) reports shall be the same ACE equation as that used during Automatic Generation Control (AGC) mode. The use of two ACE equations came as a result of NERC's comments in response to the Notice of Proposed Rulemaking regarding the interpretation of NERC Reliability Standard BAL-001-0.1a – Real Power Balancing Control Performance (BAL-001-0.1a) [2] wherein NERC stated that entities may use an Automatic Time Error Correction (ATEC) ACE equation

[1] *Western Electricity Coordinating Council Regional Reliability Standard Regarding Automatic Time Error Correction*, Order No. 723, 127 FERC Stats. & Regs. ¶ 61,176, 74 Fed. Reg. ¶ 25,422 (2009) (hereafter Order 723).

[2] *Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards*, Notice of Proposed Rulemaking, 123 FERC Stats. & Regs. ¶ 61,064, 73 Fed. Reg. ¶ 22,856 (2008).

for control but should use raw ACE for CPS reporting.[3] The industry desires to use the same ACE equation for control and reporting because it provides better a measurement of control performance.

The purpose of this proposed WECC Regional Variance to BAL-001-01.a (WECC Variance) is to replace Requirements R1 and Section D. Compliance, Subsection 2. of BAL-001-0.1a with three new requirements. In Requirement E.B.1 of the WECC Variance, the drafting team proposes to replace the NERC ACE equation with an ACE equation that includes the ATEC term. Replacing the NERC raw ACE equation with the ATEC ACE equation through a Regional Variance will require Balancing Authorities in the Western Interconnection to use the ATEC ACE for control and CPS reporting purposes. Using the ATEC ACE equation for CPS reporting is more appropriate because, as discussed further below, it is a more accurate measure of how well a Balancing Authority is controlling to its control performance target.

The drafting team for Project WECC-0068 also requests withdrawal of the BAL-001-0.1a Appendix 2 Interpretation of Requirement R1and the BAL-003-0.1b Appendix 1 Interpretation of Requirement R3. By creating a Regional Variance that replaces Requirement R1, these interpretations are no longer needed. The drafting team revised the definition for Area Control Error (ACE) in the WECC Regional Definitions to closely align with NERC definition for ACE while at the same recognizing concept of ATEC.

In order to obtain a Regional Variance[4] to a NERC Reliability Standard, it must be demonstrated that:

- The variance is not inconsistent with or less stringent than the NERC reliability standard;
- Is necessitated by a physical difference; or
- Is an alternative methodology with the same reliability objective.

Replacing the NERC ACE equation with an ATEC ACE equation is an alternative methodology with the same reliability objective as the existing BAL-001-0.1a standard. It is a method of automatically scheduling Primary Inadvertent Interchange (PII) back to other Balancing Authorities. The inclusion of the Automatic Time Error Correction term in the ACE equation changes the Balancing Authority's control performance target. The current NERC ACE equation requires that Balancing Authorities control the frequency and Interchange within their Balancing Authority Area to a target point of zero, but it allows the control to stay within a predefined range called L_{max} which is between 0.20 * |B| and $\pm L_{10}$. The proposed ACE equation, with an Automatic Time Error adjustment, works similarly to the NERC equation; however, the target

[3] *Comments of the North American Electric Reliability Corporation on the Notice of Proposed Rulemaking regarding Interchange and Transmission Loading Relief under RM08-7*, pgs 9-10, FERC Docket No. RM08-7-000, filed June 12, 2008.

[4] "Entity variance" means an aspect of a reliability standard that applies only within a particular entity or a subset of entities within a limited portion of a regional entity, such as a variance that would apply to a regional transmission organization or particular market or to a subset of bulk power system owners, operators or users. An entity variance may not be inconsistent with or less stringent than the reliability standards as it would otherwise exist without the entity variance. An entity variance shall be approved only through the NERC standards development procedure and shall be made part of the NERC reliability standards." (Rules of Procedure of the North American Electric Reliability Corporation, Section 200 — Definition of Terms, page 2.)

point for control is adjusted by the ATEC adjustment. The ATEC component defines a new control point and is equivalent to making an interchange schedule that would automatically payback PII. The modification to the ACE equation is equivalent to making an adjustment because of a metering error. Since the amount of the adjustment during any one hour is limited by L_{max}, Balancing Authorities automatically limit the risk to the interconnection and the amount of the transaction.

The addition of the I_{ATEC} component meets the standard of justification for a Regional Variance as an alternative methodology, with the same reliability objective as the NERC Reliability Standard. In addition, the proposed WECC variance to BAL-001-0.1a is consistent with — or more stringent than — the NERC BAL-001-0.1a Reliability Standard. The reasons the WECC Variance meets the standard of justification are:

1. The addition of I_{ATEC} to the ACE equation and adjustment to the control performance target used for controlling frequency and interchange does not place any addition risk to reliability because limits are set in the magnitude of the I_{ATEC} adjustment.
2. The Regional Variance allows the use of the same control performance target for control and reporting providing a better methodology for measuring performance.
3. It is another control methodology that achieves the same reliability objective as BAL-001-0.1a.

BAL-004-WECC-1 requires Balancing Authorities in the Western Interconnection to use ATEC ACE for control. As proposed in the WECC Variance, Balancing Authorities in the Western Interconnection are required to operate synchronously to the Interconnection, using the ATEC ACE, which automatically corrects time error. The ATEC component in the ACE equation has been effective in mitigating two main issues in the Western Interconnection.

1. It has been used to reduce the number of hours of Manual Time Error Corrections, or the amount of manual adjustments of timing errors that accumulate on clocks, which make certain interconnection scheduled frequency deviations.
2. Since time error is directly related to Inadvertent Interchange, the procedure has been used to reduce accumulated Inadvertent Interchange, or the difference between the actual and scheduled interchange.

The ATEC procedure requires Balancing Authorities in the Western Interconnection to determine their contribution to the Interconnection time error. The Balancing Authority does this by calculating its PII. BAL-001-0.1a Requirement E.B.1 requires that each Balancing Authority calculate its PII_{accum} and I_{ATEC} from its hourly Inadvertent Interchange. When the resulting I_{ATEC} is entered into Balancing Authority's ACE equation, I_{ATEC} continuously corrects for its portion of the time error automatically, as opposed to manually, as specified in the continent-wide standard on Time Error Correction BAL-004-1 Requirement R2. Although the maximum payback is bounded between limits, the continuous correction enables equitable payback of Primary Inadvertent Interchange.

The drafting team is proposing the same Violation Severity Levels for Requirement R1 of the WECC Variance as those in Requirement R1 of BAL-001-01.a because it is a measurement of how well a Balancing Authority is controlling to its control performance target.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post draft standard for 45-day NERC comment period	02/01/2012
2. NERC comment period ends	03/27/2012
3. Operating Committee approves proposed standard	03/27/2012
4. DT completes review and consideration of industry comments to NERC posting	04/27/2012
5. Post draft standard for WECC Board approval	05/01/2012
6. WECC Board approval	06/21/2012
7. Post draft standard for 15-day NERC comment period	06/25/2012
8. NERC 15-day comment period ends	07/2012
9. DT completes review and consideration of industry comments to NERC posting	07/2012
10. Submit NERC Board of Trustees approval request	08/2012
11. Receive NERC Board approval	08/2012

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Implementation Plan

The proposed Implementation Plan is to make the WECC Regional Variance to BAL-001-0.1a and the proposed WECC Regional Reliability Standard BAL-004-WECC-2 effective on the first day of the second quarter, after regulatory approval. Since entities are already controlling with the ATEC ACE equation, but are using the NERC raw ACE equation for purposes of reporting CPS1, the transition to controlling and reporting using the ATEC ACE should be minimal. Additionally, it should not require much time to implement the limits to a Balancing Authority's Accumulated Primary Inadvertent Interchange.

Definitions of Terms Used in Regional Variance to a NERC Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the NERC Glossary under WECC Regional Definitions.

Area Control Error: The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection.

A. Introduction

1. Title: **Real Power Balancing Control Performance**

2. Number: BAL-001-0.1a

3. Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.

4. Applicability:

4.1. Balancing Authorities

5. Effective Date: The WECC Regional Variance to NERC Reliability Standard BAL-001-0.1a is to be effective on the first day of the second quarter, after regulatory approval.

B. Requirements

R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε_1^2 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \le \in_1^2 \; or \; \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\in_1^2} \le 1$$

Committee.

The equation for ACE is:

$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$

where:

- NI_A is the algebraic sum of actual flows on all tie lines.
- NI_S is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections.
- I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

R2. Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar

month is within a specific limit, referred to as L_{10}.

$$AVG_{10-\text{minute}}(ACE_i) \le L_{10}$$

where:

$L_{10} = 1.65 \in_{10} \sqrt{(-10B_i)(-10B_s)}$

ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.

R3. Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.

R4. Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance perspective, the Balancing Authority has shifted all control requirements to the Balancing Authority providing Overlap Regulation Service).

C. Measures

M1. Each Balancing Authority shall achieve, as a minimum, Requirement 1 (CPS1) compliance of 100%.

CPS1 is calculated by converting a compliance ratio to a compliance percentage as follows:

CPS1 = (2 - CF) * 100%

The frequency-related compliance factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the target frequency bound:

$$CF = \frac{CF_{12-\text{month}}}{(\in_1)^2}$$

where: ε_1 is defined in Requirement R1.

The rating index $CF_{12\text{-month}}$ is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, Frequency Error and Frequency Bias Settings.

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for ACE and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\frac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}\right)}{\text{-10B}}$$

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority's clock-minute compliance factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}}\right]$$

Normally, sixty (60) clock-minute averages of the reporting Balancing Authority's ACE and of the respective Interconnection's Frequency Error will be used to compute the respective hourly average compliance parameter.

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$\text{CF}_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}}[(\text{CF}_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}}[n_{\text{one-minute samples in clock-hour}}]}$$

$$\text{CF}_{\text{month}} = \frac{\sum_{\text{hours-in-day}}[(\text{CF}_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}}[n_{\text{one-minute samples in clock-hour averages}}]}$$

The 12-month compliance factor becomes:

$$\text{CF}_{\text{12-month}} = \frac{\sum_{\text{i=1}}^{12}(CF_{\text{month-i}})(n_{(\text{one-minute samples in month})-\text{i}})]}{\sum_{\text{i=1}}^{12}[n_{(\text{one-minute samples in month})\text{-i}}]}$$

In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at

least 50% of both ACE and Frequency Deviation samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or Frequency Deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and Frequency Deviation, that one-minute interval shall be excluded from the calculation of CPS1.

M2. Each Balancing Authority shall achieve, as a minimum, Requirement R2 (CPS2) compliance of 90%. CPS2 relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

$$CPS2 = \left[1 - \frac{\text{Violations}_{\text{month}}}{\left(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}}\right)}\right] * 100$$

The violations per month are a count of the number of periods that ACE clock-ten-minutes exceeded L_{10}. ACE clock-ten-minutes is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.

Violation clock-ten-minutes

= 0 if

$$\left|\frac{\sum ACE}{n_{\text{samples in 10-minutes}}}\right| \leq L_{10}$$

= 1 if

$$\left|\frac{\sum ACE}{n_{\text{samples in 10-minutes}}}\right| > L_{10}$$

Each Balancing Authority shall report the total number of violations and unavailable periods for the month. L_{10} is defined in Requirement R2.

Since CPS2 requires that ACE be averaged over a discrete time period, the same factors that limit total periods per month will limit violations per month. The calculation of total periods per month and violations per month, therefore, must be discussed jointly.

A condition may arise which may impact the normal calculation of total periods per month and violations per month. This condition is a sustained interruption in the recording of ACE.

In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples are present for that interval. Should half or more of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval shall be omitted from the calculation of CPS2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar month.

1.3. Data Retention

The data that supports the calculation of CPS1 and CPS2 (Appendix 1-BAL-001-0) are to be retained in electronic form for at least a one-year period. If the CPS1 and CPS2 data for a Balancing Authority Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved. Each Balancing Authority shall retain for a rolling 12-month period the values of: one-minute average ACE (ACE_i), one-minute average Frequency Error, and, if using variable bias, one-minute average Frequency Bias.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance – CPS1

2.1. Level 1: The Balancing Authority Area's value of CPS1 is less than 100% but greater than or equal to 95%.

2.2. Level 2: The Balancing Authority Area's value of CPS1 is less than 95% but greater than or equal to 90%.

2.3. Level 3: The Balancing Authority Area's value of CPS1 is less than 90% but greater than or equal to 85%.

2.4. Level 4: The Balancing Authority Area's value of CPS1 is less than 85%.

3. Levels of Non-Compliance – CPS2

3.1. Level 1: The Balancing Authority Area's value of CPS2 is less than 90% but greater than or equal to 85%.

3.2. Level 2: The Balancing Authority Area's value of CPS2 is less than 85% but greater than or equal to 80%.

3.3. Level 3: The Balancing Authority Area's value of CPS2 is less than 80% but greater than or equal to 75%.

3.4. Level 4: The Balancing Authority Area's value of CPS2 is less than 75%.

E. Regional Variances

E.A. The ERCOT Control Performance Standard 2 Waiver approved November 21, 2002.

E.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Interconnection and replaces, in their entirety, Requirement R1 and Section D.2. (i.e., under Compliance replace Levels of Non-Compliance – CPS1). Please note that the ACE equation is replaced in its entirety with the following equation identified in Requirement E.B.1.

Requirements and Measures

E.B.1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit $\in_1^2$ is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \le \in_1^2 \; or \; \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\in_1^2} \le 1$$

The equation for ACE in the Western Interconnection is:

$$ACE = \left(NI_A - NI_S\right) - 10B\left(F_A - F_S\right) - I_{ME} + I_{ATEC}$$

Where:

NI_A is the algebraic sum of actual flows on all tie lines.

NI_S is the algebraic sum of scheduled flows on all tie lines.

F_A is the actual frequency.

F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections.

B = Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.

I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

Rationale for E.B.1

Premise: When a Balancing Authority Area uses the ACE equation with an ATEC correction component for both control and assessing performance, it provides a more accurate measurement of the Control Performance methodology while at the same time achieving the same reliability objective as the existing BAL-001-0.1a standard.

Justification: Adding the ***I_{ATEC}*** term to the ACE equation reduces the number of manual time error corrections and PII_{accum}.

Goal: To establish an ACE equation that permits the implementation of Automatic Time Error Correction.

$I_{ATEC} = \frac{PII_{accum}^{on/off\ peak}}{(1-Y)*H}$ when operating in Automatic Time Error Correction control mode.

I_{ATEC} shall be zero when operating in any other AGC mode.

Y = B / B_S.

H = Number of Hours used to payback Primary Inadvertent Interchange energy. The value of H is set to 3.

B_S = Frequency Bias for the Interconnection (MW / 0.1 Hz).

Primary **I**nadvertent **I**nterchange **(PII_{hourly})** is **$(1-Y) * (II_{actual} - B * \Delta TE/6)$**

II_{actual} is the hourly Inadvertent Interchange for the last hour.

ΔTE is the hourly change in system Time Error as distributed by the Interconnection Time Monitor. Where:

$$\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$$

TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection Time Monitor control center clocks.

t is the number of minutes of Manual Time Error Correction that occurred during the hour.

TE_{offset} is 0.000 or +0.020 or -0.020.

PII_{accum} is the Balancing Authority's accumulated **PII_{hourly}** in MWh. An On-Peak and Off-Peak accumulation accounting is required.

Where:

$PII_{accum}^{on/off\ peak}$ **= last period's** $PII_{accum}^{on/off\ peak}$ **+** PII_{hourly}

[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

M.E.B.1. Each Balancing Authority shall achieve, as a minimum, Requirement E.B.1 (CPS1) compliance of 100%.

CPS1 is calculated by converting a compliance ratio to a compliance percentage as follows:

CPS1 = (2 - CF) * 100%

The frequency-related compliance factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the target frequency bound:

$$CF = \frac{CF_{12-month}}{(\in_1)^2}$$

where: $\in_1$ is defined in Requirement E.B.1.

The rating index $CF_{12\text{-month}}$ is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, Frequency Error and Frequency Bias Settings.

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for ACE and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\frac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}\right)}{\text{-10B}}$$

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority's clock-minute compliance factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}}\right]$$

Normally, sixty (60) clock-minute averages of the reporting Balancing Authority's ACE and of the respective Interconnection's Frequency Error are used to compute the respective hourly average compliance parameter.

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

As part of its evidence each Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$\text{CF}_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}}[(\text{CF}_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}}[n_{\text{one-minute samples in clock-hour}}]}$$

$$\text{CF}_{\text{month}} = \frac{\sum_{\text{hours-in-day}}[(\text{CF}_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}}[n_{\text{one-minute samples in clock-hour averages}}]}$$

The 12-month compliance factor becomes:

$$CF_{12\text{-month}} = \frac{\sum_{i=1}^{12}(CF_{\text{month-i}})(n_{(\text{one-minute samples in month})-i})]}{\sum_{i=1}^{12}[n_{(\text{one-minute samples in month})\text{-i}}]}$$

In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and Frequency Deviation samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or Frequency Deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and Frequency Deviation, that one-minute interval shall be excluded from the calculation of CPS1.

E.B.2. Each Balancing Authority shall limit the absolute value of I_{ATEC}, the Automatic Time Error Correction term as follows: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

$$|I_{ATEC}| \leq L_{max}.$$

Rationale for E.B.2

Premise: I_{ATEC} greater than L_{max} may result in a risk to reliability caused by large ATEC payback.

Justification: Balancing Authorities should not control their Balancing Authority Areas using an approach that puts system reliability at risk.

Goal: The goal of Requirement E.B.2 is to limit I_{ATEC} to L_{max} in order to reduce potential reliability risks to the interconnection caused by a large ATEC payback term.

M.E.B.2. Forms of acceptable evidence for Requirement E.B. 2 may include, but are not limited to:

- Dated Energy Management System (EMS) displays,
- WECC Interchange Tool, EMS application code, or
- Other archived data that demonstrates compliance.

E.B.3. Each Balancing Authority shall set L_{max} within the limits as follows:

$$0.20 * |B| \leq L_{max} \leq L_{10}.$$

[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Rationale for E.B.3

Premise: Operating within an L_{max} less than 0.20 * |B| may not provide sufficient correction for PII and operating with an L_{max} greater than L_{10} may result in potential reliability risks caused by a large ATEC payback term.

Justification: L_{max} should be limited to prevent Balancing Authorities from creating potential reliability risks caused by a large ATEC payback term.

Goal: The goal of Requirement E.B.3 is to develop a range for L_{max} where Balancing Authorities reduce potential reliability risks by limiting I_{ATEC} to L_{max}.

M.E.B.3. Forms of acceptable evidence for Requirement E.B. 3 may include, but is not limited to:

- Dated Energy Management System (EMS) displays,
- WECC Interchange Tool, EMS application code, or
- Other archived data that demonstrates compliance.

E.B. Compliance

1. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority in the Western Interconnection shall retain the values of I_{ATEC} and L_{max} for the preceding calendar year (January – December), as well as the current calendar year.

Table of Compliance Elements

E #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
E.B.1	Real-time Operations	Medium	The Balancing Authority Area's value of CPS1 was less than 100% but greater than or equal to 95%.	The Balancing Authority Area's value of CPS1 was less than 95% but greater than or equal to 90%.	The Balancing Authority Area's value of CPS1 was less than 90% but greater than or equal to 85%.	The Balancing Authority Area's value of CPS1 was less than 85%.
E.B.2	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority Area's absolute value for I_{ATEC} was greater than L_{max}.
E.B.3	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority did not set L_{max} to within the limits in E.B.3 (i.e., $0.20 * \|B\| \leq L_{max} \leq L_{10}$).

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	Revised
0a	January 16, 2008	In Section A.2., Added “a” to end of standard number In Section F, corrected automatic numbering from “2” to “1” and removed “approved” and added parenthesis to “(October 23, 2007)”	Errata
0	January 23, 2008	Reversed errata change from July 24, 2007	Errata
0.1a	October 29, 2008	Board approved errata changes; updated version number to “0.1a”	Errata
0.1a	May 13, 2009	Approved by FERC	
		WECC Regional Variance Retirement of Appendix 2 Interpretation of Requirement R1	

Appendix 1-BAL-001-0
CPS1 and CPS2 Data

CPS1 DATA	Description	Retention Requirements
ε_1	A constant derived from the targeted frequency bound. This number is the same for each Balancing Authority Area in the Interconnection.	Retain the value of ε_1 used in CPS1 calculation.
ACE_i	The clock-minute average of ACE.	Retain the 1-minute average values of ACE (525,600 values).
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value(s) of B_i used in the CPS1 calculation.
F_A	The actual measured frequency.	Retain the 1-minute average frequency values (525,600 values).
F_S	Scheduled frequency for the Interconnection.	Retain the 1-minute average frequency values (525,600 values).

CPS2 DATA	Description	Retention Requirements
V	Number of incidents per hour in which the absolute value of ACE clock-ten-minutes is greater than L_{10}.	Retain the values of V used in CPS2 calculation.
ε_{10}	A constant derived from the frequency bound. It is the same for each Balancing Authority Area within an Interconnection.	Retain the value of ε_{10} used in CPS2 calculation.
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value of B_i used in the CPS2 calculation.
B_s	The sum of Frequency Bias of the Balancing Authority Areas in the respective Interconnection. For systems with variable bias, this is equal to the sum of the minimum Frequency Bias Setting.	Retain the value of B_s used in the CPS2 calculation. Retain the 1-minute minimum bias value (525,600 values).
U	Number of unavailable ten-minute periods per hour used in calculating CPS2.	Retain the number of 10-minute unavailable periods used in calculating CPS2 for the reporting period.

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Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard
Date submitted: 10/15/09
Date accepted: 10/23/09
Contact information for person requesting the interpretation:
Name: John Van Boxtel
Organization: Western Electricity Coordinating Council
Telephone: 360-713-9090
E-mail: jvanboxtel@wecc.biz
Identify the standard that needs clarification:
Standard Number: CIP-004-1
Standard Title: Cyber Security – Personnel and Training
Identify specifically what requirement needs clarification:

Requirement Number and Text of Requirement: R2, R3, and R4

R2. Training — The Responsible Entity shall establish, maintain, and document an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and review the program annually and update as necessary.

R2.1. This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained within ninety calendar days of such authorization.

R3. Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access. A personnel risk assessment shall be conducted pursuant to that program within thirty days of such personnel being granted such access. Such program shall at a minimum include:

R4. Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets.

Clarification needed (emphasis added):

Specifically, the WECC RC seeks clarification on the definition of “authorized access” as applied to temporary support from vendors.

Do the training, risk assessment and access requirements specified in R2, R3, and R4 apply to vendors who are supervised? Assuming that a “supervised” vendor is exempt from CIP-004-1, Requirements R2, R3 and R4, would

temporary, indirect and monitored access such as that provided through remote terminal sessions (WebEx, etc.) or escorted physical access be considered supervision?

Background

Through previously published documents, both NERC and FERC have indicated that the intent of the CIP-004 Standard was to document training, risk assessment, and access to Critical Cyber Assets in situations where personnel have direct and unmonitored access to critical cyber assets, as opposed to and distinguishable from **supervised access.**

The question asked in Frequently Asked Questions CIP-004-1 Cyber Security – Personnel & Training is: "*What is meant by 'authorized cyber access?'" The answer provided is:*

> *The phrase "authorized cyber access" is similar in intent to "authorized unescorted physical access" (see Standard CIP-006, Requirement R1.6). In other words, the phrase refers to permitting ("authorizing") someone to have "trusted," unsupervised access in a cyber environment. Other than in emergency situations, some form of supervision is appropriate for anyone with cyber access who has not been subjected to a personnel risk assessment and appropriate training. Procedures covering cyber access under emergency circumstances must be covered in the Responsible Entity's cyber security policy as required by Standard CIP-003.* (emphasis added)

This answer is also consistent with a similar description of escorted access provided in FERC Order 706, page 116, paragraph 432, in which the Commission stated:

> *Entergy and SDG&E recommend that newly-hired employees be allowed access to critical cyber assets if they are accompanied by qualified escorts. We note that a qualified escort would have to possess enough expertise regarding the critical cyber asset to ensure that the actions of the newly-hired employee or vendor did not harm the integrity of the critical cyber asset or the reliability of the Bulk-Power system. However, if the escort is sufficiently qualified, we believe such escorted access could be permitted before a newly-hired employee is trained.* (emphasis added)

Identify the material impact associated with this interpretation:

Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard.

Material Impact

If "Authorized Access" includes temporary support access provided in a supervised manner, then there is a potential for many Registered Entities to either be noncompliant while seeking support, or excessively burdened by limiting access to timely support. This situation is particularly likely from large non-utility vendors (such as Cisco Systems) that are either unable or unwilling to provide dedicated support personnel who have complied with each individual Registered Entity's specific cyber security training and risk assessment programs, as required by the standard.

Specifically the following requirements would create operational and administrative issues not only for Registered Entities but also for vendors in typical supervised support situations:

- Training covering the specific policies, access controls, and procedures as developed by each individual Registered Entity.
- A personnel risk assessment for all support personnel provided by each individual vendor, based on the cyber security training program developed by each individual Registered Entity.
- Timely updates to each Registered Entity's access list of all support personnel provided by each individual vendor, including changes in personnel at the vendor within the timeframes prescribed by the standard.

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Project 2009-26: Response to Request for an Interpretation of NERC Standard CIP-004-1 for the Western Electricity Coordinating Council

The following interpretation of NERC Standard CIP-004-1 Cyber Security — Personnel & Training, Requirements R2, R3, and R4, was developed by the Cyber Security Order 706 SAR drafting team.

Requirement Number and Text of Requirement

R2. Training — The Responsible Entity shall establish, maintain, and document an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and review the program annually and update as necessary.

R2.1. This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained within ninety calendar days of such authorization.

R3. Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access. A personnel risk assessment shall be conducted pursuant to that program within thirty days of such personnel being granted such access. Such program shall at a minimum include:

R4. Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets.

Question

The WECC RC seeks clarification on the definition of "authorized access" as applied to temporary support from vendors.

Do the training, risk assessment and access requirements specified in R2, R3, and R4 apply to vendors who are supervised? Assuming that a "supervised" vendor is exempt from CIP-004-1, Requirements R2, R3 and R4, would temporary, indirect and monitored access such as that provided through remote terminal sessions (WebEx, etc.) or escorted physical access be considered supervision?

Response

~~The drafting team interprets that a vendor may be granted escorted physical access to Critical Cyber Assets; however, for a vendor to be granted authorized cyber access, the vendor must complete the risk assessment and training as required by CIP-004-1 Requirement R2. CIP-003-1 Requirement R3 permits exceptions to an entity's cyber security policy, such as for an event requiring emergency access. It is recognized that the cited question and answer from the *Frequently Asked Questions CIP-004-1 Cyber Security – Personnel & Training* document states that "…some form of supervision is appropriate for anyone with cyber access who has not been subjected to a personnel risk assessment and appropriate training." However, this particular guidance should be revisited. For purposes of CIP-004-1, there is no way to provide effective escorted or supervised *cyber* access to ensure that the actions of vendors who have not received the cyber security training and a personnel risk assessment do not harm the integrity of a Critical Cyber Asset or the reliability of the bulk power system during that electronic access. It is further noted that an FAQ is not a standard, and cannot create or dilute the language of the standard itself.~~

WECC asks three questions, which are listed below. The answer to each question follows the question.

1. WECC seeks clarification on the definition of "authorized access" as applied to temporary support from vendors.

Answer: While the *Glossary of Terms used in NERC Reliability Standards* does not have a definition of "authorized access," CIP-004-1, Requirement R4 requires that an entity "shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets." For purposes of CIP-004-1, an individual has "authorized access" if he or she is on that list, and, as a result, is subject to Requirements R2, R3, and R4.

2. Do the training, risk assessment, and access requirements specified in R2, R3, and R4 apply to vendors who are supervised?

Answer: As written, all cyber access to Critical Cyber Assets must be authorized, and all authorized access must comply with Requirements R2, R3, and R4.[1] Through the use of the qualifier "unescorted" with regard to physical access, CIP-004-1, Requirement R2, implies the concept of supervision for physical access when an individual is not authorized, and CIP-006 R1.6 also allows for escorted unauthorized physical access via a visitor program. There is no similar qualifier or reference in the requirement that mentions "escorted" or otherwise implies supervision for cyber access within CIP-004. Furthermore, there is no mention of any escorted unauthorized cyber access within CIP-007 similar to the visitor program in CIP-006 R1.6. Compared to "physical access," the concept or any words relating to "escorting" or "supervision" in the requirement language is absent relative to cyber access.

3. Assuming that a "supervised" vendor is exempt from CIP-004-1, Requirements R2, R3, and R4, would temporary, indirect and monitored access such as that provided through remote terminal sessions (WebEx, etc.) or escorted physical access be considered supervision?

Answer: To the extent a vendor is escorted to physically access a Critical Cyber Asset for purposes other than direct cyber access (e.g., replacing parts on the Critical Cyber Asset), supervision is acceptable (within the context of escorted physical access). If the escorted physical access includes bringing a vendor or other individual to the Critical Cyber Asset to direct someone with authorized access in performing cyber access, such supervision is also acceptable within the language of the requirement, since the vendor or other individual is merely present while an authorized individual conducts the actual cyber access. However, the requirement language does not support the notion of physically escorting a vendor or other individual to a Critical Cyber Asset for the vendor or other individual to perform cyber access, even if supervised. Even if it is possible to provide supervised cyber access to Critical Cyber Assets, there is no basis or contemplation of "escorted" cyber access whatsoever in CIP-004, whether remotely or in person.

[1] The drafting team also notes that the FAQ referenced in the request for interpretation is not the same as an approved Reliability Standard and is not mandatory and enforceable. The FAQ was not developed or approved through the same standards development process, and cannot be used to substitute for the language in the standard itself. The drafting team also notes that the concept of unsupervised trusted access in the FAQ applies only to Version 1—which contained a 30 and 90 day provision for training and personnel risk assessments for personnel with authorized cyber access and authorized unescorted physical access—and it was not modified to conform to the changes made in subsequent versions.

A. Introduction

1. Title: Cyber Security — Personnel & Training

2. Number: CIP-004-3

3. Purpose: Standard CIP-004-3 requires that personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including contractors and service vendors, have an appropriate level of personnel risk assessment, training, and security awareness. Standard CIP-004-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. Applicability:

4.1. Within the text of Standard CIP-004-3, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator.

4.1.2 Balancing Authority.

4.1.3 Interchange Authority.

4.1.4 Transmission Service Provider.

4.1.5 Transmission Owner.

4.1.6 Transmission Operator.

4.1.7 Generator Owner.

4.1.8 Generator Operator.

4.1.9 Load Serving Entity.

4.1.10 NERC.

4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-004-3:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Awareness — The Responsible Entity shall establish, document, implement, and maintain a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets receive on-going reinforcement in sound security practices. The program shall include security awareness reinforcement on at least a quarterly basis using mechanisms such as:

- Direct communications (e.g., emails, memos, computer based training, etc.);
- Indirect communications (e.g., posters, intranet, brochures, etc.);
- Management support and reinforcement (e.g., presentations, meetings, etc.).

R2. Training — The Responsible Entity shall establish, document, implement, and maintain an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. The cyber security training program shall be reviewed annually, at a minimum, and shall be updated whenever necessary.

R2.1. This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained prior to their being granted such access except in specified circumstances such as an emergency.

R2.2. Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004-3, and include, at a minimum, the following required items appropriate to personnel roles and responsibilities:

R2.2.1. The proper use of Critical Cyber Assets;

R2.2.2. Physical and electronic access controls to Critical Cyber Assets;

R2.2.3. The proper handling of Critical Cyber Asset information; and,

R2.2.4. Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.

R2.3. The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and attendance records.

R3. Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets. A personnel risk assessment shall be conducted pursuant to that program prior to such personnel being granted such access except in specified circumstances such as an emergency.

The personnel risk assessment program shall at a minimum include:

R3.1. The Responsible Entity shall ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and seven-year criminal check. The Responsible Entity may conduct more detailed reviews, as permitted by law and subject to existing collective bargaining unit agreements, depending upon the criticality of the position.

R3.2. The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.

R3.3. The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and that personnel risk assessments of contractor and service vendor personnel with such access are conducted pursuant to Standard CIP-004-3.

R4. Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets.

R4.1. The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, or any change in the access rights of such personnel. The Responsible Entity shall ensure access list(s) for contractors and service vendors are properly maintained.

R4.2. The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.

C. Measures

M1. The Responsible Entity shall make available documentation of its security awareness and reinforcement program as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation of its cyber security training program, review, and records as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of the personnel risk assessment program and that personnel risk assessments have been applied to all personnel who have authorized cyber or authorized unescorted physical access to Critical Cyber Assets, as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation of the list(s), list review and update, and access revocation as needed as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep personnel risk assessment documents in accordance with federal, state, provincial, and local laws.

1.4.2 The Responsible Entity shall keep all other documentation required by Standard CIP-004-3 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	01/16/06	D.2.2.4 — Insert the phrase "for cause" as intended. "One instance of personnel termination for cause…"	03/24/06
1	06/01/06	D.2.1.4 — Change "access control rights" to "access rights."	06/05/06
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Reference to emergency situations. Modification to R1 for the Responsible Entity to establish, document, implement, and maintain the awareness program. Modification to R2 for the Responsible Entity to establish, document, implement, and maintain the training program; also stating the requirements for the cyber security training program. Modification to R3 Personnel Risk Assessment to clarify that it pertains to personnel having authorized cyber or authorized unescorted physical access to "Critical Cyber Assets". Removal of 90 day window to complete training and 30 day window to complete personnel risk assessments. Changed compliance monitor to Compliance Enforcement Authority.	
3		Update version number from -2 to -3	
3	12/16/09	Approved by NERC Board of Trustees	Update

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Standards Announcement

Project 2009-26 Interpretation of CIP-004-x for WECC

Project 2010-INT-05 Interpretation of CIP-002-x for Duke

Two Ballot Pool Windows Now Open through 8 a.m. Eastern on March 8, 2012
Two Formal Comment Periods Open through Friday 8 p.m. March 23, 2012
Two Ballot Windows (One Initial and One Successive) Open March 14 – 23, 2012

Now Available Here:

Project 2010-INT-05 CIP-002-x Interpretation of CIP-002-x for Duke
Project 2009-26 Interpretation of CIP-004-x for WECC

The CIP Interpretation Drafting team has posted two CIP Interpretations for formal comment periods through 8 p.m. Eastern on Friday, March 23, 2012. Ballot pools are being formed for each interpretation through **8 a.m. Eastern on Thursday, March 8** (*please note that ballot pools close at 8 a.m. on the day they close*). Ballots of each interpretation will be conducted during the last ten days of the comment period, from Wednesday, March 14 through Friday, March 23, 2012, closing at 8 p.m. Eastern.

Instructions for Joining Ballot Pools

Separate ballot pools are being formed for each interpretation. Although a ballot pool was previously formed for Project 2009-26, the Standards Committee has authorized forming a new ballot pool to ensure that current Registered Ballot Body members have an opportunity to participate.

To join the ballot pools to be eligible to vote in the upcoming ballots of each interpretation, go to: Join Ballot Pool

During the pre-ballot windows, members of each ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) One ballot pool list server has been set up and can be used for communication on each of the interpretations.

The list servers for each interpretation project are:

Project 2009-26 Interpretation of CIP-004-x for WECC: bp-2009-26_CIP-004-1_SB_in@nerc.com

Project 2010-INT-05 Interpretation of CIP-002-x for Duke Energy bp-2010-INT-05_CIP-002_in@nerc.com

Instructions for Commenting

A formal comment period is open for each interpretation through **8 p.m. Eastern on Friday, March 23, 2012**. Each interpretation has a separate comment form. Please use the links below to submit comments using the electronic comment form for each interpretation. Off-line, unofficial copies of the comment forms are posted on the project pages.

Project 2010-INT-05 Interpretation of CIP-002-x for Duke	Electronic comment form	Project page
Project 2009-26 Interpretation of CIP-004-x for WECC	Electronic comment form	Project page

If you experience any difficulties in using the electronic forms, please contact Monica Benson at monica.benson@nerc.net.

Next Steps

A successive ballot window will be open for the interpretation in Project 2009-26 Interpretation of CIP-004-x for WECC from Wednesday, March 14 through 8 p.m. Eastern on Friday, March 23, 2012.

An initial ballot window will be open for the interpretation in Project 2010-INT-05 Interpretation of CIP-002-x for Duke from Wednesday, March 14 through 8 p.m. Eastern on Friday, March 23, 2012.

Background

In May 2011, the Standards Committee appointed a standing CIP Interpretation Drafting Team and assigned the further development of all outstanding CIP Interpretations, including the two referenced in this announcement, to that team. Initial drafts of each of the two CIP interpretations were developed by a different drafting team. The CIP Interpretation Drafting Team has reviewed all comments submitted in the previous postings of each interpretation, along with FERC orders issued since the previous posting, and has revised the interpretations in response to comments and consistent with guidance adopted by the NERC Board of Trustees and Standards Committee.

Additional information about each project is available on the individual project pages:

Project 2010-INT-05 Interpretation of CIP-002-x for Duke
Project 2009-26 Interpretation of CIP-004-x for WECC

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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A. Introduction

1. Title: Cyber Security — Critical Cyber Asset Identification

2. Number: CIP-002-3

3. Purpose: NERC Standards CIP-002-3 through CIP-009-3 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3 requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. Applicability:

4.1. Within the text of Standard CIP-002-3, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator.

4.1.2 Balancing Authority.

4.1.3 Interchange Authority.

4.1.4 Transmission Service Provider.

4.1.5 Transmission Owner.

4.1.6 Transmission Operator.

4.1.7 Generator Owner.

4.1.8 Generator Operator.

4.1.9 Load Serving Entity.

4.1.10 NERC.

4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-002-3:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. Effective Date: The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

B. Requirements

R1. Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.

R1.1. The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.

R1.2. The risk-based assessment shall consider the following assets:

R1.2.1. Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.

R1.2.2. Transmission substations that support the reliable operation of the Bulk Electric System.

R1.2.3. Generation resources that support the reliable operation of the Bulk Electric System.

R1.2.4. Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.

R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

R1.2.6. Special Protection Systems that support the reliable operation of the Bulk Electric System.

R1.2.7. Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.

R2. Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.

R3. Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a control center; or,

R3.3. The Cyber Asset is dial-up accessible.

R4. Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

C. Measures

M1. The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.

M2. The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.

M3. The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.

M4. The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.

1.1.2 ERO for Regional Entity.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep documentation required by Standard CIP-002-3 from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	January 16, 2006	R3.2 — Change "Control Center" to "control center"	03/24/06
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version number from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	Update

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Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard

Date submitted: 1/31/10

Date revised version submitted: 7/22/10

Contact information for person requesting the interpretation:

Name: Kim Long

Organization: Duke Energy Corporation

Telephone: 704-382-7179

E-mail: kim.long@duke-energy.com

Identify the standard that needs clarification:

Standard Number (include version number): CIP-002-1

(example: PRC-001-1)

Standard Title: Cyber Security – Critical Cyber Asset Identification

Identify specifically what requirement needs clarification:

Requirement Number and Text of Requirement: CIP – 002-1, Requirement R3

R3. Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a control center; or,

R3.3. The Cyber Asset is dial-up accessible.

Clarification needed:

With regard to the above requirements, Duke Energy respectfully requests an interpretation as to the following:

1. Is the phrase "***Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange"*** meant to be prescriptive, i.e., that any and all systems and facilities utilized in monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange, must be classified as Critical Cyber Assets, or is this phrase simply meant to provide examples of the types of systems that should be *assessed* for inclusion in the list of Critical Cyber Assets using an entity's critical cyber asset methodology?
2. What does the phrase, ***"essential to the operation of the Critical Asset"*** mean? If an entity has an asset that "may" be used to operate a Critical Asset, but is not "required" for operation of that Critical Asset, is the asset considered "essential to the operation of the Critical Asset"? Remote access to the systems is valuable to operations (see Material Impact Statement below), but operation of the Critical Asset is not literally dependent on these laptops.
    - *The term "essential" is not defined in the NERC Glossary. T*he Merriam –Webster dictionary provides the following definition of essential: "**ESSENTIAL** implies belonging to the very nature of a thing and therefore being incapable of removal without destroying the thing itself or its character." The dictionary provides the following synonyms for essential: "Inherent, basic, indispensible, vital, fundamental, and necessary."

Identify the material impact associated with this interpretation:

Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard.

If the phrase 'Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control' is meant to be prescriptive such that workstations, which are utilized in monitoring and control must be classified as Critical Cyber Assets, then the ability to provide remote support is not available to companies.

It is inherently not possible to implement all of the prescribed controls, i.e. CIP 006 physical controls, around workstations such as laptops when used from remote locations. The reliability of the Bulk Electric System will be eroded, rather than enhanced, if companies do not have the ability to remotely access the Critical Asset environment by utilizing laptop workstations with the cyber security controls prescribed in CIP 005.

Interpretation 2010-INT-05: Response to Request for an Interpretation of NERC Standard CIP-002-1 R3 for the Duke Energy Corporation

The following interpretation of NERC Standard CIP-002-1 Cyber Security — Critical Cyber Asset Identification was developed by a sub team of the Cyber Security Order 706 Standard Drafting Team.

Requirement Number and Text of Requirement

R3. Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
R3.2. The Cyber Asset uses a routable protocol within a control center; or,
R3.3. The Cyber Asset is dial-up accessible.

Question 1

Is the phrase “Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange” meant to be prescriptive, i.e., that any and all systems and facilities utilized in monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange, must be classified as Critical Cyber Assets, or is this phrase simply meant to provide examples of the types of systems that should be assessed for inclusion in the list of Critical Cyber Assets using an entity’s critical cyber asset methodology?

Response to Question 1

The phrase “Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange” is illustrative, not prescriptive. It simply provides examples of the types of Cyber Assets that should be considered. It does not imply that the items listed must be classified as Critical Cyber Assets, nor is it intended to be an exhaustive list of Critical Cyber Asset types.

Question 2

What does the phrase, "essential to the operation of the Critical Asset" mean? If an entity has an asset that "may" be used to operate a Critical Asset, but is not "required" for operation of that Critical Asset, is the asset considered "essential to the operation of the

Critical Asset"? Remote access to the systems is valuable to operations (see Material Impact Statement below), but operation of the Critical Asset is not literally dependent on these laptops.

Response to Question 2

The word "essential" is not defined in the *Glossary of Terms used in NERC Reliability Standards*, but the well-understood meaning and ordinary usage of the word "essential" implies "inherent to" or "necessary." The phrase "essential to the operation of the Critical Asset" means inherent to or necessary for the operation of the Critical Asset.

A Cyber Asset that "may" be used, but is not "required" (i.e., without which a Critical Asset cannot function as intended), for the operation of a Critical Asset is not "essential to the operation of the Critical Asset" for purposes of Requirement R3. Similarly, a Cyber Asset that is merely "valuable to" the operation of a Critical Asset, but is not necessary for or inherent to the operation of that Critical Asset, is not "essential to the operation" of the Critical Asset.

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Standards Announcement

Project 2009-26 Interpretation of CIP-004-x for WECC

Project 2010-INT-05 Interpretation of CIP-002-x for Duke

Two Ballot Pool Windows Now Open through 8 a.m. Eastern on March 8, 2012
Two Formal Comment Periods Open through Friday 8 p.m. March 23, 2012
Two Ballot Windows (One Initial and One Successive) Open March 14 – 23, 2012

Now Available Here:

Project 2010-INT-05 CIP-002-x Interpretation of CIP-002-x for Duke
Project 2009-26 Interpretation of CIP-004-x for WECC

The CIP Interpretation Drafting team has posted two CIP Interpretations for formal comment periods through 8 p.m. Eastern on Friday, March 23, 2012. Ballot pools are being formed for each interpretation through **8 a.m. Eastern on Thursday, March 8** (*please note that ballot pools close at 8 a.m. on the day they close*). Ballots of each interpretation will be conducted during the last ten days of the comment period, from Wednesday, March 14 through Friday, March 23, 2012, closing at 8 p.m. Eastern.

Instructions for Joining Ballot Pools

Separate ballot pools are being formed for each interpretation. Although a ballot pool was previously formed for Project 2009-26, the Standards Committee has authorized forming a new ballot pool to ensure that current Registered Ballot Body members have an opportunity to participate.

To join the ballot pools to be eligible to vote in the upcoming ballots of each interpretation, go to: Join Ballot Pool

During the pre-ballot windows, members of each ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) One ballot pool list server has been set up and can be used for communication on each of the interpretations.

The list servers for each interpretation project are:

Project 2009-26 Interpretation of CIP-004-x for WECC: bp-2009-26_CIP-004-1_SB_in@nerc.com

Project 2010-INT-05 Interpretation of CIP-002-x for Duke Energy bp-2010-INT-05_CIP-002_in@nerc.com

Instructions for Commenting

A formal comment period is open for each interpretation through **8 p.m. Eastern on Friday, March 23, 2012**. Each interpretation has a separate comment form. Please use the links below to submit comments using the electronic comment form for each interpretation. Off-line, unofficial copies of the comment forms are posted on the project pages.

Project 2010-INT-05 Interpretation of CIP-002-x for Duke	Electronic comment form	Project page
Project 2009-26 Interpretation of CIP-004-x for WECC	Electronic comment form	Project page

If you experience any difficulties in using the electronic forms, please contact Monica Benson at monica.benson@nerc.net.

Next Steps

A successive ballot window will be open for the interpretation in Project 2009-26 Interpretation of CIP-004-x for WECC from Wednesday, March 14 through 8 p.m. Eastern on Friday, March 23, 2012.

An initial ballot window will be open for the interpretation in Project 2010-INT-05 Interpretation of CIP-002-x for Duke from Wednesday, March 14 through 8 p.m. Eastern on Friday, March 23, 2012.

Background

In May 2011, the Standards Committee appointed a standing CIP Interpretation Drafting Team and assigned the further development of all outstanding CIP Interpretations, including the two referenced in this announcement, to that team. Initial drafts of each of the two CIP interpretations were developed by a different drafting team. The CIP Interpretation Drafting Team has reviewed all comments submitted in the previous postings of each interpretation, along with FERC orders issued since the previous posting, and has revised the interpretations in response to comments and consistent with guidance adopted by the NERC Board of Trustees and Standards Committee.

Additional information about each project is available on the individual project pages:

Project 2010-INT-05 Interpretation of CIP-002-x for Duke
Project 2009-26 Interpretation of CIP-004-x for WECC

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2011-INT-02 Rapid Revision of VAR-002 | Corrected Documents Posted
Date: Thursday, February 09, 2012 10:34:17 AM

Standards Announcement

Project 2011-INT-02 Rapid Revision of VAR-002

Corrected Documents Posted

Ballot Pool Now Open through 8 a.m. Eastern on March 8, 2012
Formal Comment Period Open through 8 p.m. Eastern on Friday, March 23, 2012
Initial Ballot Window Open March 14 – 23, 2012

Now Available

The word "Operator" was inadvertently deleted in the revised Requirement R1 of VAR-002-2b. A corrected version, with the reinserted word highlighted in red, has been posted along with a corrected mapping document.

Thank you.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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Project 2011-INT-02 - Interpretation of VAR-002 for Constellation

Mapping Document *(Updated February 9, 2012 to correspond to the updated Requirement R1)*

Mapping

Translation of VAR-002-1.1b - Generator Operation for Maintaining Network Voltage Schedules into VAR-002-2b - Generator Operation for Maintaining Network Voltage Schedules.

Standard: VAR-002-2b		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed language in VAR-002-2b - Generator Operation for Maintaining Network Voltage Schedules**
R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.	Revised to address Interpretation Request	**R1.** The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

Standard: VAR-002-2b		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed language in VAR-002-2b - Generator Operation for Maintaining Network Voltage Schedules**
		• That the unit is being operated in start-up[1] or shutdown[2] mode pursuant to a procedure previously provided to the Transmission Operator; or. • That the unit is not being operated in the automatic voltage control mode for a reason other than start-up or shutdown.
	All other requirements remain unchanged with the exception of the addition of Time Horizons and previously approved Violation Risk Factors and	R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[3]) as directed by the Transmission Operator. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to

[1] Start-up is deemed to have ended when the unit is ramped up to its minimum load and the unit is preparing for continuous operation.
[2] Shutdown is deemed to begin when the unit is ramped down to its minimum load and the unit is preparing to go offline.
[3] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

Standard: VAR-002-2b		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed language in VAR-002-2b - Generator Operation for Maintaining Network Voltage Schedules**
	Violation Severity Levels.	control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator. R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met. R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability. R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability. R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission

Standard: VAR-002-2b		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed language in VAR-002-2b - Generator Operation for Maintaining Network Voltage Schedules**
		Planner within 30 calendar days of a request. [Violation Risk Factor: Lower] [Time Horizon: Real-time Operations] R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage: R4.1.1. Tap settings. R4.1.2. Available fixed tap ranges. R4.1.3. Impedance data. R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers. R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] R5.1. If the Generator Operator can't comply with the Transmission Operator's specifications,

Standard: VAR-002-2b		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed language in VAR-002-2b - Generator Operation for Maintaining Network Voltage Schedules**
		the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

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Standards Authorization Request Form

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Generator Operation for Maintaining Network Voltage Schedules		
Date Submitted:	January 13, 2012		
SAR Requester Information			
Name:	Stephen Crutchfield		
Organization:	NERC		
Telephone:	609-651-9455	E-mail:	Stephen.crutchfield@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
This SAR proposes to modify VAR-002-1b, R1 to address an ambiguity in the standard.
Purpose or Goal (How does this request propose to address the problem described above?):
N/A
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
N/A

SAR Information
Brief Description (Provide a paragraph that describes the scope of this standard action.)
This SAR proposes to modify VAR-002-1b, R1 to address an ambiguity in the standard.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Requirement R1 of VAR-002-1.1b states the following: R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator. NERC received a request to interpret this requirement. The requester stated: "During startup and shutdown of a generator, it is industry practice to have a generator's AVR in the manual mode. Due to the instabilities associated with the changes in the field during these times, it is more reliable to have an operator control the generator than the AVR. Further, an AVR's response is slower and more unreliable when the field current is low, which is the case during start up and shut down. Both the BA and TOP realize that during start up and shut down the real and reactive power from that generator cannot be counted upon for system stability. Some regions have taken the stance that during start up and shut down of a generator, it is reasonable to assume that the AVR is in manual and that it will be switched to automatic once stable. This would not require contacting the TOP to state that the AVR is in manual for this time period. Other regions have taken the approach that all status changes of the AVR from automatic, regardless of industry practice and stability, needs to be communicated to the TOP. Constellation is seeking clarification of Requirement R1 as to whether or not a communication must be conducted between a GOP and a TOP during start up or shut down of a generator, when

SAR Information
the unit is not stable and is not counted upon for real or reactive power by the BA and TOP at that time. Constellation has found two issues caused by the lack of clarity/incorrect interpretation of this standard: 1. There is not a consistent view across the regions with regard to this requirement. Such inconsistencies are contrary to the intent of NERC's CMEP and can expose entities to inconsistent evaluations. A procedure may be compliant in one region and may not be in another. 2. Requiring a GOP to communicate that the AVR is in manual during start up/shutdown is an unnecessary distraction at a time when the unit is unstable. A generator operator already communicates to the TOP that the unit is being started up or shutting down. Adding another communication imposes a redundant task when the generator operator is focused on controlling the unit and ensuring the reliability of the BES." The Standards Committee approved the use of a "rapid modification" approach to clarify the requirement in question directly in lieu of a formal interpretation. The Interpretation Team is proposing the attached modification to the standard in lieu of an Interpretation. The redline standard includes the FERC approved VRFs and VSLs for this standard.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

Reliability Functions	
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.
☐ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐ Distribution Provider	Delivers electrical energy to the End-use customer.
☒ Generator Owner	Owns and maintains generation facilities.
☒ Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐ Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐ Market Operator	Interface point for reliability functions with commercial functions.
☐ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation

Related Standards	

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	

Regional Variances	
WECC	

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Standards Announcement

Project 2011-INT-02 Rapid Revision of VAR-002

Ballot Pool Now Open through 8 a.m. Eastern on March 8, 2012
Formal Comment Period Open through 8 p.m. Eastern on Friday, March 23, 2012
Initial Ballot Window Open March 14 – 23, 2012

Now Available

The Standards Committee has authorized processing a request for interpretation of VAR-002-1b Requirement R2 as a "rapid revision" of the standard, rather than as an interpretation, with the requester's permission. A "rapid revision" uses the normal standard development process to make a clarifying change to a standard. The drafting team formed for this project has posted a draft SAR, along with the clean and redline versions of the revised standard and an implementation plan, for a parallel formal comment period with a ballot during the last ten days of the comment period, through March 23, 2012. A ballot pool is being formed and the ballot pool window is open through 8 a.m. Eastern on Thursday, March 8, 2010

Instructions for Joining the Ballot Pool

A ballot pool is being formed to ballot VAR-002-2b. The ballot pool window is open through 8 a.m. Eastern on Thursday, March 8, 2010 (please note that ballot pool windows close at 8 a.m. Eastern on the day they close).

To join the ballot pool to be eligible to vote in the upcoming ballot of the standard and associated implementation plan, go to: Join Ballot Pool

During the pre-ballot windows, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this project is: bp-2011-INT-02_VAR-002_in@nerc.com

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Friday, March 23, 2012**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Special Instructions for Submitting Comments with a Ballot

Please note that comments submitted during the formal comment period and the ballots for the standards both use the same electronic form, and will be compiled into a single report with duplicate comments submitted by the same entity removed and duplicate comments submitted by multiple entities consolidated. **Therefore, it is NOT necessary for ballot pool members to submit more than one set of comments. The drafting team requests that all stakeholders (ballot pool members as well as other stakeholders) submit all comments through the electronic comment form.**

Next Steps

The drafting team will consider all comments submitted to determine whether to make additional revisions to the standard.

Background

Constellation Energy submitted a request for interpretation of VAR-002-1.1b asking for clarification of Requirement R1 and whether the requirement requires generation units to be operated in automatic voltage control mode during start-up and shut-down. Additional information is available on the project webpage.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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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. SAR and proposed standard drafted and approved for posting (January 2012).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard to address an interpretation request by Constellation. The draft standard includes previously approved Time Horizons, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a 45-day concurrent formal comment period and initial ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop second version draft standard.	March – April 2012
2. Post response to comments and conduct successive ballot.	May-June 2012
3. Develop responses to ballot comments.	June-July 2012
4. Post responses to comments and conduct recirculation ballot.	July 2012
5. BOT adoption.	August 2012
6. File with regulatory authorities.	October 2012

A. Introduction

1. Title: **Generator Operation for Maintaining Network Voltage Schedules**

2. Number: VAR-002-~~1.1b~~2b

3. Purpose: To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.

4. Applicability

4.1. Generator Operator.

4.2. Generator Owner.

~~**5.Effective Date:** Immediately after approval of applicable regulatory authorities.~~

5. Effective Date: In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after Board of Trustees approval.

B. Requirements

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator~~.~~ of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the unit is being operated in start-up[1] or shutdown[2] mode pursuant to a procedure previously provided to the Transmission Operator; or.
- That the unit is not being operated in the automatic voltage control mode for a reason other than start-up or shutdown.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[3]) as directed by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

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[1] Start-up is deemed to have ended when the unit is ramped up to its minimum load and the unit is preparing for continuous operation.

[2] Shutdown is deemed to begin when the unit is ramped down to its minimum load and the unit is preparing to go offline.

[3] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

R4.1.1. Tap settings.

R4.1.2. Available fixed tap ranges.

R4.1.3. Impedance data.

R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1. If a generator is being started up or shut down with the automatic voltage control off and no notification to the Transmission Operator is made, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode. Such evidence must include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's directives as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

For entities that do not work for the Regional ~~Reliability Organization.~~

Entity, the Regional Entity shall serve as the Compliance ~~**Monitoring Period and Reset Time Frame**~~Enforcement Authority.

~~One calendar year.~~

For functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Operator shall maintain evidence needed for Measure 1 through Measure 5 and Measure 7 for the current and previous calendar years.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure 6)

The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

~~1.3.~~1.4. **Additional Compliance Information**

~~The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.~~

None

2. Violation Severity Levels ~~of Non-Compliance for Generator Operator~~

~~**2.1.Level 1:** There shall be a Level 1 non-compliance if any of the following conditions exist:~~

~~**2.1.1**One incident of failing to notify the Transmission Operator as identified in, R3.1, R3.2 or R5.1.~~

~~**2.1.2**One incident of failing to maintain a voltage or reactive power schedule (R2).~~

~~**2.2.Level 2:** There shall be a Level 2 non-compliance if any of the following conditions exist:~~

~~**2.2.1**More than one but less than five incidents of failing to notify the Transmission as identified in R1, R3.1, R3.2 or R5.1.~~

~~**2.2.2**More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).~~

~~**2.3.Level 3:** There shall be a Level 3 non-compliance if any of the following conditions exist:~~

~~**2.3.1**More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.~~

~~**2.3.2**More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).~~

~~**2.4.Level 4:** There shall be a Level 4 non-compliance if any of the following conditions exist:~~

~~**2.4.1**Failed to comply with the Transmission Operator's directives as identified in R2.~~

~~**2.4.2**Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.~~

~~**2.4.3**Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).~~

~~**3.Levels of Non-Compliance for Generator Owner:**~~

~~**3.1.1Level One:** Not applicable.~~

~~**3.1.2Level Two:** Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in R4.1.1 through R4.1.4.~~

~~**3.1.3Level Three:** No documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage~~

~~**3.1.4Level Four:** Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The responsible entity did not operate each generator in the automatic voltage control mode and failed to notify the Transmission Operator as identified in R1.

R2.	When directed by the Transmission Operator to maintain the generator voltage or reactive power output the Generator Operator failed to meet the directed values by 5% or less.	When directed by the Transmission Operator to maintain the generator voltage or reactive power output the Generator Operator failed to meet the directed values by more than 5% up to (and including) 10% OR When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator. OR The Generator Operator failed to provide an explanation of why the voltage schedule could not be met.	When directed by the Transmission Operator to maintain the generator voltage or reactive power output the Generator Operator failed to meet the directed values by more than 10% up to (and including) 15%	When directed by the Transmission Operator to maintain the generator voltage or reactive power output the Generator Operator failed to meet the directed values by more than 15%. OR When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator and the Generator Operator failed to provide an explanation of why the voltage schedule could not be met.
R3.	N/A	N/A	The Generator Operator failed to notify the Transmission Operator within 30 minutes of the information as specified in either R3.1 or R3.2	The Generator Operator failed to notify the Transmission Operator within 30 minutes of the information as specified in both R3.1 and R3.2
R4.	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner one of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was provided in more than	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner two of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner three of the types of data as specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4 OR The information was	The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner any of the types of data as specified in R4.1.1 and R 4.1.2 and 4.1.3 and 4.1.4 OR The information was

	30, but less than or equal to 35 calendar days of the request.	The information was provided in more than 35, but less than or equal to 40 calendar days of the request.	provided in more than 40, but less than or equal to 45 calendar days of the request.	provided in more than 45 calendar days of the request.
R5.	N/A	N/A	N/A	The responsible entity failed to ensure that transformer tap positions were changed according to the specifications provided by the Transmission Operator when said actions would not have violated safety, an equipment rating, a regulatory requirement, or a statutory requirement.
R5.1.	N/A	N/A	N/A	The responsible entity failed to notify the Transmission Operator and to provide technical justification.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 — Interpretation of Requirements R1 and R2 (August 1, 2007).

Version History

Version	Date	Action	Change Tracking
1	May 15, 2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	December 19, 2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	January 16, 2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	October 29, 2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	March 3, 2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2	TBD	Revised R1 to address an Interpretation Request. Also added VRFs, Time Horizons and VSLs.	Revised

Appendix 1

Interpretation of Requirements R1 and R2

Request:

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage ***or Reactive Power output*** as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation:

1. First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

   Interpretation: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

   Interpretation: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

Appendix 2

Interpretation of VAR-002-1a

Request:
VAR-002 — Generator Operation for Maintaining Network Voltage Schedules, addresses the generator's provision of voltage and VAR control. Confusion exists in the industry and regions as to which requirements in this standard apply to Generator Operators that operate generators that do not have automatic voltage regulation capability.

The Standard's requirements do not identify the subset of generator operators that need to comply – forcing some generator operators that do not have any automatic voltage regulation capability to demonstrate how they complied with the requirements, even when they aren't physically able to comply with the requirements. Generator owners want clarification to verify that they are not expected to acquire AVR devices to comply with the requirements in this standard.

Many generators do not have automatic voltage regulators and do not receive voltage schedules. These entities are at a loss as to how to comply with these requirements and are expending resources attempting to demonstrate compliance with these requirements. A clarification will avoid challenges and potential litigation stemming from sanctions and penalties applied to entities that are being audited for compliance with this standard, but who do not fall within the scope or intent of the standard itself.

Please identify which requirements apply to generators that do not operate generators equipped with AVRs.

Response: All the requirements and associated subrequirements in VAR-002-1a apply to Generator Owners and Generator Operators that own or operate generators whether equipped with an automatic voltage regulator or not. The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation. A generator that is not equipped with an automatic voltage regulator results in a functionally equivalent condition to a generator equipped with an automatic voltage regulator that is out of service due to maintenance or failure.

There are no requirements in the standard that require a generator to have an automatic voltage regulator, nor are there any requirements for a Generator Owner to modify its generator to add an automatic voltage regulator. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.

A Report on

Assessing the Need for Introducing Demand Response Functions and Entities to the NERC Reliability Functional Model

Prepared by: Functional Model Demand Response Advisory Team

Executive Summary

The Functional Model Working Group Demand Response Advisory Team (FMDRAT) has completed an assessment of the need to include Demand Response (DR) functions and associated functional entities either in the NERC Functional Model (FM) or as an Applicable Entity for NERC Standards.

The FMDRAT assessed a number of key issues related to the role and reliability impacts of DR in the planning and operation horizons. This assessment leads to the following key conclusions and recommendations:

1) DR is generally considered in BES planning and operations from the perspective of resource adequacy assessment and operating reserve determination. Long-term planners, operational planners and operators do take into account the amount of DR under contractual agreement or participated in operating reserve market to adjust resource needs to meet forecast system demand and reserve requirements. Since DR itself is not an active facility or component like a generator, its “dispatch” action is initiated upon receiving instructions from the operating authorities under pre-determined system conditions. Compared to sudden load increase and generator tripping, DR’s spontaneous performance or failure to perform as instructed does not pose adverse reliability impacts on the BES for which there is no recourse. Hence, there is not a need at this time to include DR in the Functional Model to describe its role in contributing to BES reliability.
2) Imposing reliability standards to force entities responsible for DR operations to comply with commercial agreements would be inappropriate, may not achieve the desired outcome, and in fact may discourage entities from participating in DR programs. There is thus no urgency or need to develop reliability standards to ensure compliance with what is essentially a business arrangement with commercial mechanisms already in place to drive the desired outcome.
3) The FMWG should continue to monitor DR development and identify if and when DR technology and penetration levels create a unique impact on BES reliability.

1.0 Introduction

The Functional Model Working Group Demand Response Advisory Team (FMDRAT) has completed an assessment of the need to include Demand Response (DR) functions and associated functional entities either in the NERC Functional Model (FM) or as an Applicable Entity for NERC Standards. The issues considered by the FMDRAT and the key findings after discussing these issues are summarized in this report for consideration by the Functional Model Working Group (FMWG).

The FMDRAT is made up of 14 members appointed by the NERC Standards Committee. The FMDRAT's roster is included as Attachment 1.

2.0 Background

In 2008, the FMWG set up a small advisory team to assess the need to create a DR function and a DR entity. That advisory team concluded that such a function and related functional entity were not justified at that time. The Advisory Team also suggested that the FMWG reconsider the issue when developing Functional Model Version 5 (FM V5). The advisory team recommended consideration of assigning such functions and responsibilities to functions and entities already defined in the FM.

The FMWG reconsidered the issue in its development of FM V5, and again concluded that there was no justification for defining a DR function and entity in the FM V5 Model. The NERC Planning Committee at its December 8-9, 2009, meeting, when approving the FM V5, requested the FMWG reassess the need to include a DR Functional Entity in FM V6. Below is the excerpt from the Planning Committee's meeting minutes:

Functional Model Version 5: FMWG Chair Jim Cyrulewski presented an overview of the Functional Model, version 5. On a motion by John Simpson, the PC approved V5, without modification, the technical content of two documents: Reliability Functional Model, Function Definitions and Functional Entities and Reliability Functional Model Technical Document.

The primary discussion focused on what was not in version 5: a functional entity (or entities) responsible for demand resources. Mr. Cyrulewski noted that when the FMWG presents version 5 to the Standards Committee (SC) in January 2010 for approval, it will be recommending a new subgroup be formed to address the demand resources function so that it can be incorporated in version 6. John Simpson suggested that the PC's Resource Issues Subcommittee be involved in that effort.

The Standards Committee in response to the FMWG's request approved the formation of the FMDRAT to address the Planning Committee's request. The FMDRAT was formed in May 2010, and from September 2010 to February 2011 completed its assignment to assess the need for a DR function and entity. This report presents the FMDRAT's assessment and recommendations.

3.0 Key Issues Addressed by the FMDRAT

The FMDRAT began its tasks by identifying and compiling a list of potential reliability impacts associated with the participation of DR. The issues were important because the Functional Model is a general description of the primary reliability tasks that need to be performed to ensure reliability of the Bulk Electric System (BES).

Presented below is a summary of the FMDRAT's assessment of each of the identified key issues.

3.1 Reliability Impact of DR - *Does the change in energy use from a DR asset or from an aggregation of DR assets create any unique reliability impact?*

Demand Response (DR) is a temporary change in electricity usage by a Demand Resource in response to market or reliability conditions.[1] Demand Response is regarded as a "dispatchable" resource (as opposed to energy efficiency, which is always "on") whose deployment is driven by pre-determined system conditions or reliability event criteria by an operating entity. The system operator typically provides instruction to the DR provider for deployment of DR assets. Additionally, DR providers may self-schedule DR asset deployment, as in the case for economic dispatch in some regions.

A DR asset or aggregator that functions according to operating conditions as defined by prior agreements poses no impact to reliability because its impacts are analyzed and assessed in the Operating Plans of the respective Transmission Operator (TOP) and Balancing Authority (BA).

The TOP and BA plan in advance to meet system load, including load that is represented or controlled by DR entities. TOPs and BAs have knowledge of all relevant conditions and agreements, and plan operations accordingly for the load to be served with or without contribution from DR.

To the BA, load is a composite value (i.e., not locational) and a forecast can be developed for how much capacity is required to meet that load. Contractual arrangements with DR providers are accounted for in the BA's operating plans.

To the TOP, load is locational and it is based on historic load bus values. The DR control of load does not change the location of the basic load; rather, the availability of DR provides the TOP with another option to control congestion and to maintain reliability.

The impacts from a failure of DR to respond on the power system are no different from a situation where a Generator Operator does not generate to its cleared energy quantity or does not respond to requests to raise generation. At present, there are no reliability standards that mandate a Generator Operator to comply with the business agreements. There are mechanisms in some areas (e.g. in some organized markets) to levy a penalty on

[1] North American Energy Standards Board, Wholesale Electric Quadrant definition, 2010

the Generator Operator for not meeting its commitment or requested output, but this is a commercial arrangement which falls outside of the scope of the NERC Functional Model or reliability standards. BAs and TOPs are similarly free to prescribe penalties for comparable failures of DR. Such penalty structures are not currently described in the Functional Model, nor are there reliability standards developed to enforce compliance to such penalties.

Observation 1: DR may be considered a dispatchable resource as compared to energy efficiency, which is always "on"; it is also regarded as a load whose contractual arrangement to be reduced in response to operating instructions or market mechanism is well-known to the operators. At present, there does not appear to be any adverse reliability impact on the BES unique to DR resources where there is no recourse either for the DR's reduction of load as planned or requested, or the DR's failure to reduce load as planned or requested.

3.2 Reliance on DR to provide Operating Reserves

In some organized markets, DR may participate in the reserve market. In non-organized markets, DR may enter into contractual arrangements with the host utility to provide reserve capability. The FMDRAT assessed that the BA was responsible for ensuring adequate reserves in the operations time frame, and the BA was required to understand the characteristics of the DR resources regardless of the market setup, and the BA was required to develop the necessary recourses to guard against DR's failure to perform. Again, this situation is no different than generators not providing operating reserves. At present, there are no reliability standards that mandate a Generator Operator to provide the needed reserves as procured or requested by the Balancing Authority.

To manage the potential risk that DR fails to provide the dispatched or self-scheduled reserve quantity agreed upon, some organized markets apply a discount factor to the amount of reserves offered by a DR resource, while some organized markets limit DR participation to 30-minute reserve services. Still others do not count on the DR to begin with, but as load drops off, the responsible entity backs down the generation loaded in response to the activation in order to maintain adequate operating reserves.

Similar measures were determined by the FMDRAT to be adopted in non-organized markets through contractual arrangements.

Observation 2: TOPs or BAs are responsible for managing the load and supply balance in their control areas. Dispatchable DR resources are generally considered in resource adequacy and operating reserve assessments in the operational planning time frame. However, it does not appear that DR presents any new or different risks to the BES compared to any other dispatchable resource available to the TOP or BA. All responsible entities have measures in place to guard against the possibility that any dispatchable resource does not fulfill its obligations to provide the agreed amount of reserves. There are no adverse reliability impacts on the BES for which there is no recourse when DR resources do not perform as planned or requested to provide the needed reserve.

3.3 DR resources' obligations to support resource planning

Many planning entities consider DR in their mid-term and long-term resource planning processes. Some Planning entities consider DR as a resource to help meet the reserve margin requirement that is determined by either the traditional loss-of-load expectation (LOLE) process or by other commonly used methodologies.

Projected available DR may be applied as an available resource to help meet a reserve margin requirement, or applied as an offset to the long-term load forecast. Some planning entities apply a forced outage rate to the DR, similar to dispatchable generators, and simulate DR performance in LOLE calculations. In each case, some uncertainty exists around long-term DR resource availability due to the short term contractual nature of DR assets as compared to the expected life of a generation asset. Some entities conduct more frequent resource adequacy assessments as the planning horizon approaches the near-term. An additional DR functional entity will not change the current role or responsibility of the planning coordinator or the resource planner.

Observation 3: Some entities consider DR in long-term planning and its treatment varies from one entity to another. However, owing to the long lead time in the planning process, there is uncertainty as to whether or not the status of the DR will remain unchanged as it approaches real time. An additional DR functional entity will not change the current role or responsibility of the planning coordinator or the resource planner.

3.4 Need for reliability standards to enforce compliance with contractual agreements/obligations

At present, DR is usually arranged via contractual agreements or market mechanisms such as pricing thresholds, reserve offerings, or forward capacity auctions. In these arrangements, penalties are levied if commercial or contractual obligations are not met. These mechanisms are similar to generators bidding into and being dispatched in an energy market and getting paid the market price or another pre-determined price based on the amount of generation provided. In such cases generators would not be paid (and in some cases assessed with additional penalties) if they failed to generate at the agreed upon or committed level. Given these contractual or commercial payment/penalty mechanisms, there do not appear to be gaps that would require the development and enforcement of reliability standards to achieve the desired DR performance. Imposing reliability standards to force compliance to commercial agreements is inappropriate, may not actually achieve the desired outcome, and may in fact discourage load from participating in DR programs.

The FMDRAT further assessed whether DR is a fundamental component or product of the BES. DR can provide some flexibility in both the long-term and operational planning time frames, to the extent that the responsible entities can choose which loads continue to be

supplied. As such, DR may be considered a derivative product that should continue to be handled by commercial arrangements, not reliability standards.

Observation 4: Reliability standards are not required to enforce DR to comply with contractual agreements or obligations since DR participation is essentially a commercial arrangement. There are little or no material reliability impacts if DR fails to perform as agreed to or as requested (from Observations 1 and 2, above). Imposing reliability standards to force compliance to commercial agreements may not achieve the desired outcome of ensuring long-term reliability and may discourage entities from participating in DR programs.

3.5 DR Ownership and Operations – roles and relationships with others

In consideration of the possibility of introducing DR functions and entities to the Functional Model, the FMDRAT developed a draft set of tasks describing a Demand Response Ownership function and the relationship between the DR Owner and others. The FMDRAT also developed a draft set of tasks for a Demand Response Operations function and the relationship between the DR Operator and others. The objective of this exercise was to compare the primary functions between the two types of resource providers.

The FMDRAT concluded that a parallel to the tasks and relationships developed for the Generator Ownership and Generator Operations and their respective functional entities could be drawn for DR. The draft list of tasks and relationships for the DR Ownership and Operation functions and for the DR Owner and DR Operator is provided in Appendix A for information only. The FMDRAT did not finalize or accept the list provided in Appendix A in light of the FMDRAT's assessment that introducing DR functions and associated entities to the Functional is not required at this time. The list is provided herein only as a matter of record for future reference and is not part of the FMDRAT's recommendation at this time.

3.6 Conclusion of Majority Position

A near-unanimous consensus of the FMDRAT agreed with the analysis made for each of the key issues and the corresponding assessments detailed in this section of this report. The same majority agreed that that there is not a demonstrated need to introduce DR functions and entities to the Functional Model at this time.

4.0 Minority Position

The key counter-arguments centre on the comparable obligations between DR Owner/Operator and Generator Owner/Operator (GO/GOP). At present, there are a number of reliability standards that apply to GOs and GOPs. DR providers may offer their product into energy or ancillary services markets and receive compensation for successful performance. They should bear the same obligations as their generation counterparts and hence should have a comparable set of reliability standards imposed on the DR Owners and

Operators. However, if DR is not introduced to the Functional Model and if DR were required to meet the same reliability standards, then a number of standards currently applied to GO and GOP, as listed in Appendix B, should be removed from the NERC reliability standards.

The FMDRAT assessed these minority views and arrived at the following assessments:

Apart from the fact that both generation and DR provide resources to the BES, there are some fundamental differences between them. Generators are a fundamental part of the integrated power system; they provide primary products for BES reliability – energy and ancillary services. Generators do change output in reaction to system changes and their changes are largely governed by their inherent physical characteristics and auxiliary device settings. These characteristics and settings need to be verified and modeled, and the simulated generator performance needs to be assessed against specific standards criteria to ensure that any adverse effects are self-contained or isolated without propagating to other parts of the BES which could result in uncontrolled or cascade tripping. It is largely on this basis, to ensure acceptable generator performance, that reliability standards are developed and imposed on GO and GOP.

DR is a derivative or supplementary part or product of the power system, with specific rules for participation in BES operations. DR augments the capabilities of the BES thus increasing the effective utilization of the BES, but it does not expand the capability of the system to serve more loads, unlike its generator counterpart.

DR changes in load are inherently independent of system changes. Therefore, reliability standards are not needed to ensure acceptable performance as in the case of their generator counterpart. Commercial arrangements and compensation/penalty mechanisms are in place to govern DR contractual obligations and are sufficient to drive the desired behaviour when DR is called upon to act. Imposing reliability standards to enforce such behaviour is inappropriate and unnecessary and may not actually achieve the desired outcome.

As to the request to remove the listed reliability standards for the GO and GOP, the FMDRAT did not agree to a position since such a determination was not part of our charter.

5.0 Conclusions and Recommendations

The FMDRAT assessed a number of key issues related to the role and reliability impacts of DR in the planning and operation horizons. The assessment leads to the following conclusions:

1. DR is generally considered in BES planning and operations from the perspective of resource adequacy assessment and operating reserve determination. Long-term planners, operational planners and operators do take into account the amount of DR under contractual agreement or participated in operating reserve market to adjust resource needs to meet forecast system demand and reserve requirements. Since DR itself is not an active facility or component like a generator, its “dispatch” action is initiated upon receiving instructions from the operating authorities under pre-determined system conditions. Compared to sudden load increase and

generator tripping, DR's spontaneous performance or failure to perform as instructed does not pose adverse reliability impacts on the BES for which there is no recourse.

2. All responsible entities have some measures in place to guard against the possibility that a DR resource does not fulfill its obligations to provide the agreed amount of reserves.

3. For long-term planning, most entities include contributions from DR to some extent. Uncertainties associated with DR's long-term commitment to remain "dispatchable" are typically addressed by applying a discount factor or probability analysis to DR's availability in resource adequacy assessments.

4. In operational planning, there are no known entities that count on DR as a critical component of their operational plans. An additional DR functional entity will not change the current role or responsibility of the planning coordinator, resource planner, or operations planner.

5. Reliability standards are not required to enforce DR compliance with contractual agreements or obligations. There are little or no reliability impacts caused by the failure of DR resources to perform as agreed to or as requested. Therefore imposing reliability standards to force compliance with commercial agreements would be inappropriate, may not achieve the desired outcome, and in fact may discourage entities from participating in DR programs.

6. DR is a reactive component and a derivative product of the power system; it augments the capabilities of the BES thus increasing the effective utilization of the BES but it does not expand the system's capability to serve more load and does not move spontaneously or in response to system changes for which reliability standards might be needed to ensure acceptable performance. Having commercial arrangements and compensation/penalty mechanisms in place to govern their contractual obligations would suffice to drive DR to achieve the desired behavior. Imposing reliability standards to enforce such behavior is extraneous and unnecessary.

Conclusions (1) to (4) suggest that there is no need at this time to include DR in the Functional Model to describe its role in contributing to BES reliability. Conclusions (5) and (6) suggest that there is no urgency or need to develop reliability standards to ensure compliance with what is essentially a business arrangement with commercial mechanisms in place to drive the desired outcome.

It is on the above basis that the FMDRAT recommends:

1. **DR functions and their associated functional entities not be defined and introduced to the Functional Model at this time.**

2. **The FMWG continue to monitor DR development and identify if and when DR technology and penetration levels create a unique impact on BES reliability.**

Attachment 1

The Functional Model Demand Response Advisory Team

	Name	Company
	Ben Li (Chair/Facilitator)	Ben Li Associates
1	Albert DiCaprio	PJM
2	Phil Davis	Schneider Electric
3	Stephen C. Knapp	Constellation Energy Commodities Group, Inc.
4	John D. Varnell	Tenaska Power Services Co
5	Donna Pratt	NYISO
6	Ken Clark (did not participate)	Consert, Inc.
7	Aaron Breidenbaugh	EnerNOC
8	Wayne Van Liere	EON US
9	Ulric Kwan	Pacific Gas & Electric Company
10	Eric Winkler, Ph.D.	ISO New England
11	Paul Wattles	Electric Reliability Council of Texas (ERCOT ISO)
12	John Simpson	RRI Energy
13	Andy Satchwell	Lawrence Berkeley National Lab
14	Tony Jankowski	We Energy

Appendix A
DRAFT List of Perceived Tasks and Relationships for Demand Response Functions and Entities

(The list is provided for information and for future reference only; it is not part of the FMDRAT's recommendation at this time.)

Generation	Demand Response
Generator Ownership Function **Tasks** 1. Establish generating facilities ratings, limits, and operating requirements. 2. Design and authorize maintenance of generation plant protective relaying systems, protective relaying systems on the transmission lines connecting the generation plant to the transmission system, and Special Protection Systems. 3. Maintains owned generating facilities. 4. Provide verified generating facility performance characteristics / data. **Functional Entity – Generator Owner** The functional entity that owns and maintains generating units. **Relationships with Others** 1. Provides generator information to the Transmission Operator, Reliability Coordinator, Balancing Authority, Transmission Planner, and Resource Planner. 2. Provides unit maintenance schedules and unit retirement plans to the Transmission Operator, Balancing Authority, Transmission Planner, and Resource Planner.	**Demand Response Ownership Function** **Tasks** 1. Establish demand response facility ratings, limits, and operating requirements. 2. Design and authorize maintenance of demand response facilities and associated control devices. 3. Maintains owned demand response facilities. 4. Provide verified demand response facility performance characteristics / data. **Functional Entity – Demand Response Owner** The functional entity that owns and maintains demand response facilities. **Relationships with Others** 1. Provides demand response information to the Transmission Operator, Reliability Coordinator, Balancing Authority, Transmission Planner, and Resource Planner. 2. Provides demand response facility maintenance schedules to the Transmission Operator, Balancing Authority, Transmission Planner, and Resource Planner.

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3. Develops an interconnection agreement with Transmission Owner on a facility basis.
4. Receives approval or denial of transmission service request from Transmission Service Provider.
5. Provides reliability related services to Purchasing-Selling Entity pursuant to agreement.
6. Reports the annual maintenance plan to the Reliability Coordinator, Balancing Authority and Transmission Operator.
7. Revises the generation maintenance plans as requested by the Reliability Coordinator.

Function – Generator Operation

Tasks

1. Formulate daily generation plan.
2. Report operating and availability status of units and related equipment, such as automatic voltage regulators.
3. Operate generators to provide real and reactive power or reliability-related services per contracts or arrangements.
4. Monitor the status of generating facilities.
5. Support Interconnection frequency.

Functional Entity – Generator Operator

The functional entity that operates generating

3. Reports the annual maintenance plan to the Reliability Coordinator, Balancing Authority and Transmission Operator.
4. Revises the demand resource facility maintenance plans as requested by the Reliability Coordinator.

Function – Demand Response Operation

Tasks

1. Formulate daily demand response resource plan.
2. Report operating and availability status of demand response related equipment and control devices.
3. Operate demand response facility control devices or otherwise implement demand reduction or demand increase in response to instructions or according to contract arrangements.
4. Monitor the status of demand response facilities.

Functional Entity – Demand Resource Operator

The functional entity that operates demand

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unit(s) and performs the functions of supplying energy and reliability related services.	response facilities and performs the functions of curtailing or increasing demand in response to instructions or in accordance with contractual arrangement.
Relationship with Others	**Relationship with Others**
Ahead of Time	**Ahead of Time**
1. Operate generators to provide real and reactive power or reliability-related services per contracts or arrangements.	1. Implement demand reduction or consumption increase in response to instructions or according to contract arrangements.
2. Provides operating and availability status of generating units to Balancing Authority and Transmission Operators for reliability analysis.	2. Provides operating and availability status of demand response to Balancing Authority, Transmission Operator and Reliability Coordinator for reliability analysis.
3. Reports status of automatic voltage or frequency regulating equipment to Transmission Operators.	3. Provides operational data to Reliability Coordinator.
4. Provides operational data to Reliability Coordinator.	4. Receives reliability analyses from Reliability Coordinator.
5. Receives reliability analyses from Reliability Coordinator.	
6. Receives notice from Purchasing-Selling Entity if Arranged Interchange approved or denied.	
7. Receives reliability alerts from Reliability Coordinator.	
8. Receives notification of transmission system problems from Transmission Operators.	

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Real Time	**Real Time**
9. Provides Real-time operating information to the Transmission Operators and the required Balancing Authority.	5. Provides Real-time operating information to the Transmission Operators and the required Balancing Authority.
10. Adjusts real and reactive power as directed by the Balancing Authority and Transmission Operators.	6. Adjusts demand in response to instructions or according to contract agreements.
	Post Real Time
	7. Provide operating information required Balancing Authority for settlement purposes

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Appendix B

Minority Views

List of NERC Reliability Standards that should be removed if DR is not Assigned the Same Obligations as GO/GOP

On the basis of comparable treatment of "supply" resources used to balance load and supply in both the planning horizon and the real time operating horizon, a BA may choose between DR and traditional generation resources to meet the load obligations on the grid. As increased use is made of DR to meet certain load requirements, lower commitments are made of traditional generation supply. This is fine as long as the DR "supply" shows up when the BA calls on it.

Penalizing a DR that doesn't perform as agreed to or requested by penalize it via market mechanism is not acceptable from a reliability perspective. If sufficient DR doesn't show up and traditional generation resources have not been committed and cannot get on-line in time to meet the aggregate demand, then some load will have to be curtailed against its desires in order to maintain BES reliability.

If it is indeed our position that whether or not DR responds when called upon that it does not impact reliability, then the following changes ought to be made to the existing reliability standards:

a) CIP Standards: remove Generator Operators from these standards. If it is not important for supply to respond when called on then we don't need these standards applied to any supply resources.

b) COM-002: remove Generator Operators from the Applicability. If DR that is used as a supply resource doesn't need to respond, then GOPs do not need to have communications with the RCs for them to respond either.

c) IRO-001,-004,-005,-010: remove Generator Owners and Generator Operators from these standards. If it is not important that DR used as a supply resource responds to the directives of the RC, then it should not be important that GO/GOPs respond either. They also should not have to provide information on their capabilities in Day Ahead or Current Day time frames. There also shouldn't be a need to coordinate any maintenance outages with the RC. After all, if a DR owner or operator can just sit out for a day, then a generator should be able to do the same thing.

d) MOD-024,-025: delete these standards. If it is not important to know or qualify the capacity of a DR resource, then we should not have to qualify the capacity of a traditional generation resource either.

e) PRC-001,-005: remove Generator Operator and Generator Owner from these standards. If it is not important to reliability that DR operate properly when called on, then we should not have to coordinate protective relays or do protection system maintenance for traditional generation resources either.

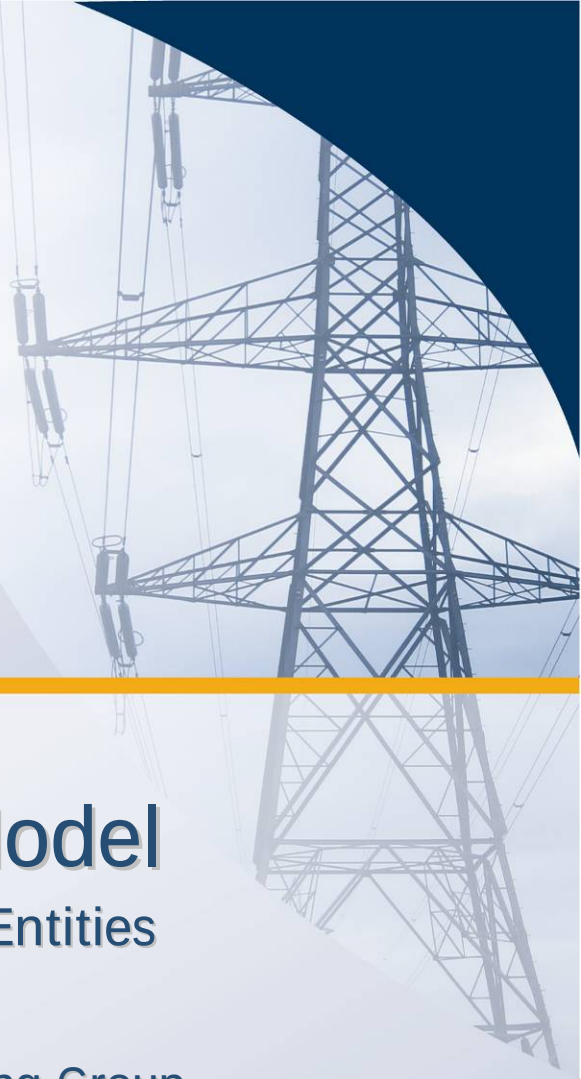
f) TOP-001,-002,-003,-006: remove Generator Operators from these standards. If it is not important that DR which is being counted on by the BA to respond to directives from the RC, then we shouldn't need to have GOPs respond either. There shouldn't be a need to coordinate normal operations planning with the RC, or coordinate outage schedules with the

RC, or provide notice to the RC of any resources that are available, or not available for dispatch.

As more and more DR is included in the dispatch stack and the planning and operating horizon, fewer real generation resources are included to meet the aggregate load obligations on the grid. It is certainly important to the BA and the RC that the real generation resources can be counted on to perform when called. As DR replaces those real generation resources, it should be important that they respond as well. Comparable reliability standard requirements should be in place for DR resources as are in place for Generator Owners and Operators.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



Reliability Functional Model

Function Definitions and Functional Entities

Version 5

Prepared by the Functional Model Working Group

Approved by Standing Committees: December 2009
Approved by Standards Committee: January 2010
Approved by Board of Trustees: May 2010

to ensure the reliability of the bulk power system

November 2009

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Revision Summary

Version 5 is an update of the Reliability Functional Model ("the Model" or "Functional Model") that includes the following changes from Version 4:

- Performed detailed analysis on the Planning functions (Planning Reliability, Transmission Planning and Resource Planning) and entities (Planning Coordinator, Transmission Planner and Resource Planner). Clarifying revisions were made to these entities, in particular with respect to the Resource Planning function.
- Interchange Authority has been changed to Interchange Coordinator. This version also incorporated the terms Arranged and Confirmed Interchange to be consistent with terminology used in the INT standards.
- Terminology
- Clarified asset ownership and maintenance for Generator Owner/Operator and Transmission Owner/Operator.
- Errata changes made as necessary.

Terminology Changes
Version 5 contains terminology changes intended to improve consistency between the Model and the NERC Glossary, the Rules of Procedure (ROP) and Reliability Standards.[1] Inconsistency has potential for creating needless complexity, confusion and wasted effort for those who use NERC documents. The changes are of three types:

- Entity terminology
- Entity names
- Entity definitions

Entity terminology

- The term "responsible entity" in the Model has been changed to "functional entity". [2]
  - The usage of "responsible" in Version 4 derives from an earlier version of the Model. Version 4 clarified that the Model is limited to describing the performance of tasks, but not compliance aspects such as responsibility for such performance. Version 5 takes this clarification one step further by replacing the term "responsible" with "functional" in the Model.
  - The Model uses the term functional entity to apply to a *class of entity*, such as a Balancing Authority, and makes no reference to the *specific organizations* that register as functional entities. Consistency within NERC documents would be

[1] Full alignment will require conforming changes in Reliability Standards, the Glossary and ROP. These changes are seen as editorial, that is not as representing changes to essential content.
[2] Version 4 actually uses "Responsible Entity". Because the Glossary and ROP generally use "responsible entity", i.e., all lower case, this usage has been adopted for version 5 of the Model.

improved if conforming changes were made to the ROP and Glossary to consistently use the term "functional entity" when the reference is to the *class of entity* (e.g., BA), and use the terms "responsible entity" and "registered entity" when the reference is to a *specific organization* regarding its responsibility or registration, respectively.[3]

Entity names

- The functional entity name Interchange Authority has been changed to Interchange Coordinator
  - The term "coordinator" better reflects the nature of the entity.
  - A conforming change is required in the Glossary
  - Conforming changes are required in other NERC documents.

Entity definitions

- The Model has been revised to define the various *functional entities*, not the *functions*, consistent with the approach used in the Glossary and standards.
- The functional entity definitions have been revised[4].
  - The form of the definitions is uniform, with each definition beginning: "The functional entity that…".
  - Each definition is single sentence, limited to a simple statement of the nature of the tasks performed. As a result some of the current descriptive wording in Version 4 or Glossary definitions has been removed in the Version 5 definitions.

[3] These changes in terminology are intended to address confusion between the entity described in the Model and specific organizations, which has been a frequently expressed concern of stakeholders.
[4] A table giving current definitions in the Model and Glossary and the proposed definitions is given in the Technical Document.

Foreword

This document replaces version 4 of the NERC Reliability Functional Model that the NERC Standing Committees approved in September 2008.

Historically, Control Areas were established by vertically integrated utilities to operate their individual power systems in a secure and reliable manner and provide for their customers' electricity needs. The traditional Control Area operator balanced its load with its generation, implemented Interchange Schedules with other Control Areas, and ensured transmission reliability.

As utilities began to provide transmission service to other entities, the Control Area also began to perform the function of Transmission Service Provider through tariffs or other arrangements. NERC's Operating Policies reflected this traditional electric utility industry structure, and ascribed virtually every reliability function to the Control Area.

Beginning in the early 1990s with the advent of open transmission access and restructuring of the electric utility industry to facilitate the operation of wholesale power markets, the functions performed by Control Areas began to change to reflect the newly emerging industry structure. These changes occurred because:

1. Some utilities were separating their transmission from their merchant functions (functional unbundling), and even selling off their generation,
2. Some states and provinces were instituting "customer choice" options for selecting energy providers, and
3. The developing power markets were requiring wide-area transmission reliability assessment and dispatch solutions, which were beyond the capability of many Control Areas to perform.

As a result, the NERC Operating Policies in place at that time, which centered on Control Area operations, were beginning to lose their focus, and become more difficult to apply and enforce.

The NERC Operating Committee formed the Control Area Criteria Task Force (CACTF) in 1999 to address this problem. The task force began by listing all the tasks required for maintaining electric system reliability and then organizing these tasks into basic groups that it called "functions." Ultimately, the Task Force decided to build a "Functional Model". This involved breaking down the previous reliability functions more finely, such that all organizations involved in ensuring reliability — whether they are traditional, vertically integrated control areas, regional transmission organizations, independent system operators, independent transmission companies or so on — can identify those functions they perform, and register with NERC as one or more of the functional entities. Initially the Model dealt with operating functions, but it was subsequently expanded in Version 2 to incorporate planning-related functions. This Functional Model framework provides guidance to NERC standards drafting teams to write reliability standards in terms of the functional entities who perform the reliability functions.

Adapted from Version 2 of the NERC Functional Model, February 10, 2004

Introduction

The NERC Reliability Functional Model provides the framework for the development and applicability of NERC's Reliability Standards as follows:

- The Model describes a set of Functions that are performed to ensure the reliability of the Bulk Electric System. Each Function consists of a set of related reliability Tasks. The Model assigns each Function to a functional entity, that is, the entity that performs the function. The Model also describes the interrelationships between that functional entity and other functional entities (that perform other Functions).
- NERC's Standards Development Teams develop Reliability Standards that assign each reliability requirement within a standard to a functional entity (that is defined in the Model and NERC's Glossary). This is possible because a given standard requirement will typically be related to a Task within a Function. A standard requirement will be very specific, whereas a Task in the Model will be more general in nature.
- NERC's compliance processes require specific organizations to register as the entities responsible for complying with standards requirements assigned to the applicable entities.
- The Model's Functions and functional entities also provide for consistency and compatibility among different Reliability Standards.

The Model is a guideline for the development of standards and their applicability. The Model it is not a Standard and does not have compliance requirements. Standards developers are not required to include all tasks envisioned in the model, nor are the developers precluded from developing Reliability Standards that address functions not described in the model. Where conflicts or inconsistency exist, the Reliability Standards requirements take precedence over the Model.

The Model is independent of any particular organization or market structure.

An organization may perform more than one Function.

The Functional Model describes a functional entity envisioned to ensure that all of the Tasks related to its Function are performed. The Model, while using the term "functional entity", is a guideline and cannot prescribe responsibility. It is NERC's compliance processes, backed by regulatory authority, that specify the manner in which, a functional entity is "legally responsible" for meeting the standards requirements assigned to that functional entity.

The work performed to meet the requirements may be self performed or performed by others.

Functional Model maintenance. The Functional Model is maintained by the Functional Model Working Group (FMWG) under the direction of the NERC Standards Committee, with technical content in the Model and accompanying technical document approved by the Standing Committees (OC, PC and CIPC)

Technical discussions. The companion document, "Functional Model – Technical Discussions," provides additional details on the Functions themselves, how organizations can "roll up" those Functions they wish to perform, and how organizations as "functional entities" interrelate.

The following terms are used in the Functional Model and do not appear in the NERC Glossary.

Functional Entity. The term used in the Functional Model which applies to a class of entity that carries out the Tasks within a Function.



Function. A set of related reliability Tasks.

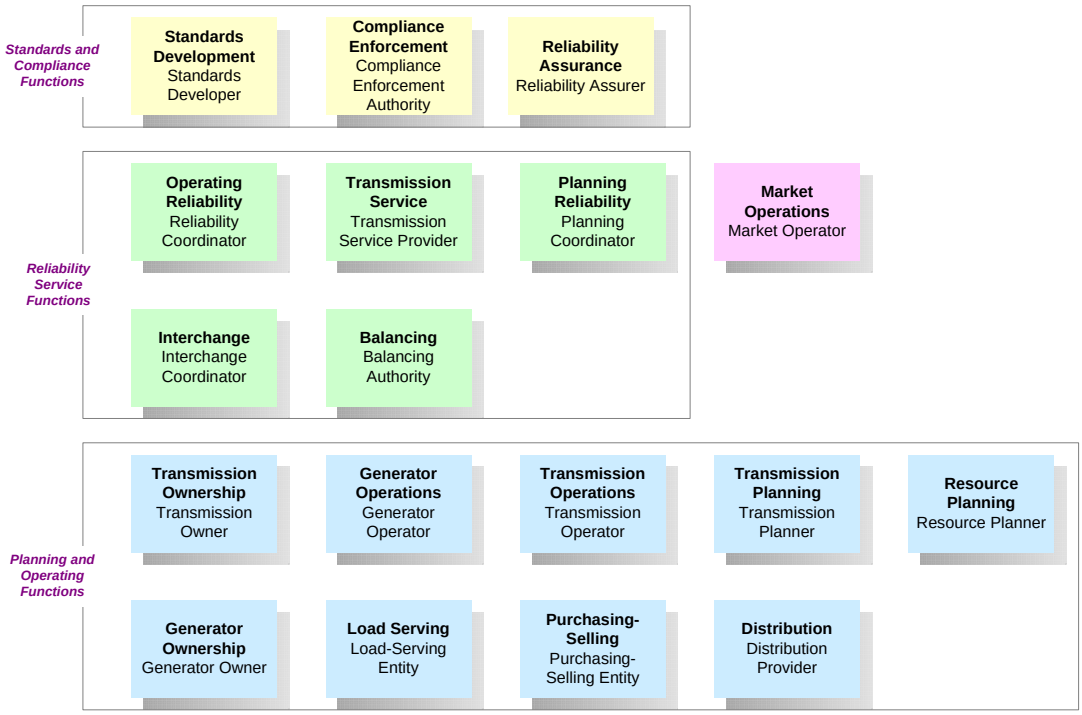
Task. One of the elements that make up a Function in the Functional Model.

Customer. The term applies to a customer for transmission, capacity or energy services (a Purchasing-Selling Entity, Generator Owner, Load-Serving Entity, or End-use Customer).



End-use Customer. The party served by a Load-Serving Entity (energy) and Distribution Provider (wire service).

Functional Model Diagram



Function Name	***Functional Entity***
Balancing	Balancing Authority
Compliance Enforcement	Compliance Enforcement Authority
Distribution	Distribution Provider
Generator Operations	Generator Operator
Generator Ownership	Generator Owner
Interchange	Interchange Coordinator
Load-Serving	Load-Serving Entity
Market Operations	Market Operator (Resource Integrator)
Operating Reliability	Reliability Coordinator
Planning Reliability	Planning Coordinator
Purchasing-Selling	Purchasing-Selling Entity
Reliability Assurance	Reliability Assurer
Resource Planning	Resource Planner
Standards Development	Standards Developer
Transmission Operations	Transmission Operator
Transmission Ownership	Transmission Owner
Transmission Planning	Transmission Planner
Transmission Service	Transmission Service Provider

Purpose of the Functional Model

The purpose of the NERC Reliability Functional Model is to:

1. Provide a framework for Reliability Standards developed through the NERC standards development process that will apply to certain Tasks defined in the Functional Model.
2. Describe in general terms each Function and the relationships between the entities that are responsible for performing the Tasks within the Functions. The framework for developing the Function definitions is:
   a. The Functions are independent of the organization structure performing the functions, and
   b. The Functions provide flexibility to accommodate the range of presently conceivable organization structures, as well as accommodate alternative tools, procedures and processes.

Guiding Principles of the Functional Model

As explained in the Introduction, the Model provides the framework on which the NERC Reliability Standards are developed and applied. To ensure that this framework remains viable, the Model itself is governed by a set of "guiding principles" that define a Function's Tasks and establish the relationships between the functional entities which are responsible for meeting the requirements in the NERC Reliability Standards that correspond to these Tasks. These principles serve as a guideline to those revising or interpreting the Model.

For further details, refer to the Technical Discussions section in the Functional Model Technical Document.

1. The Model must be *complete*, that is, it must include all reliability Tasks and interrelationships between entities performing them. This helps ensure that any reliability requirement arising in a Reliability Standard will generally be related to a Task in the Model and therefore be assignable to a particular functional entity.
2. The Model must group these Tasks into a set of Functions, such that:
    - There are enough Functions (and corresponding functional entities) to accommodate the full range of organization structures and responsibilities within the industry, and
    - The number of Functions is developed based on logical grouping of the Tasks and kept low as reasonably possible.
        - In particular, where a number of organizations that perform a given Function form a single group, the Model recognizes this as a business arrangement among organizations, not a new Function and corresponding new functional entity. That is, the fundamental reliability Tasks, and hence the Function, remain the same - all that has changed is *how* the Function is performed. Examples of such groups are a reserve sharing group (a collection of entities that are Balancing Authorities), or a planned resource sharing group.
3. The Model is structured to ensure there are no gaps or overlaps in the performance of operation Tasks in the operating timeframe anywhere in the Bulk Electric System. This is achieved in part by associating an "area" of purview for each functional entity. Areas are defined in term of the individual transmission, generator and customer equipment assets that collectively constitute the Bulk Electric System. For example, each Bulk Electric System asset has one Reliability Coordinator, one Balancing Authority, and one Transmission Operator. Regarding overlaps for planning, as described in the Technical Document, it is not always possible to achieve this in the case of planning Functions, where there may be overlapping levels of responsibility for given assets. Questions regarding relationships between the areas of different functional entities, such as whether one type of area must be totally within another type of area, will be defined in Reliability Standards or the Rules of Procedure, not the Model.
4. Tasks describe *what* is to be done, not *how* it is to be done.
5. The Model is a guideline that describes reliability Tasks and interrelationships between the entities that perform them - it is not prescriptive. In particular, the Model does not

address requirements for registering or becoming certified as a functional entity, or the delegation or splitting of responsibility for meeting standards requirements.

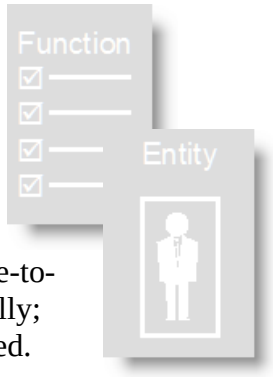
Functional Model — Clarification Service

The Functional Model is a reference tool that links functional entities with associated reliability-related functions and respective Tasks. Drafting teams use the Functional Model to help them determine which functional entity should be required to comply with each requirement in a reliability standard.

From time to time questions of clarification and interpretation arise. The FMWG is following the process described below for handling requests for clarification of the Functional Model. This process, which has been approved by the Standards Committee, is accessible to all drafting teams as well as any other interested stakeholders. If a drafting team needs help in understanding Tasks that make up a Function and/or in determining which functional entities should be responsible for particular standards requirements, the drafting team's coordinator will send an e-mail to the NERC Staff assigned as the FMWG facilitator with a request for clarification.

1. The NERC Staff assigned as the FMWG facilitator will convene a conference call/meeting of available members of the FMWG to review the question(s) and provide a clarification.
   - If the question(s) need more detailed discussion with the drafting team, the two coordinators will organize a conference call/meeting with available members of the FMWG and available members of the drafting team to discuss the issues in more detail.
2. Each FMWG request for clarification and the associated response will be posted on the NERC Functional Model Web Page under a Frequently Asked Questions section.
   - If the questions result in changes to the model, the changes will be added to a change summary table used to develop the next updated version of the Functional Model document.

Functions and Functional Entities



This section defines the functions and associated Tasks that are necessary to plan and operate the Bulk Electric System in a reliable manner. This section also characterizes the functional entities that perform these Tasks, and provides examples of the inter-relationships that take place between entities to ensure reliability. As standards are developed, the Model may be revised to add and remove Tasks under specific Functions to aid in the development of standards. Relationships between functional entities in the Model are reciprocal. Where a one-to-one relationship exists, the Model will include the reciprocal relationship specifically; and where a one-to-many relationship exists, the reciprocal relationships are implied.

Function — Standards Development

Tasks

1. Develop and maintain a standards development process.
2. Develop Reliability Standards for the planning and operation of the Bulk Electric System.



Functional Entity — Standards Developer



Definition
The functional entity that develops and maintains Reliability Standards to ensure the reliability of the Bulk Electric System.

Introduction to the Standards Developer
The Model addresses Reliability Standards created at NERC using the NERC Reliability Standards Development Procedure and Regional Standards that are created through an open Regional process and approved by NERC for enforcement. The Functional Model is intended to serve as the framework for the development and application of these Reliability Standards.[5]

Relationships with Other Functional Entities

1. Receives request for Reliability Standards through the public process.
2. Sends Reliability Standards to the Compliance Enforcement Authority.

[5] There are also Regional Criteria that are requirements that Regions create and enforce, that are not included in the Model.

Function — Compliance Enforcement



Tasks

1. Develop, maintain and implement a compliance enforcement process.
2. Evaluate and document compliance.

Functional Entity — Compliance Enforcement Authority

Definition

The functional entity that monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the standards.

Relationships with Other Functional Entities

1. Receives Reliability Standards from the Standards Developer.
2. Administers the compliance enforcement process for all functional entities as required by Reliability Standards.



Function — Reliability Assurance

Tasks

1. Coordinate reliability assurance among adjacent Reliability Assurers through the development of necessary protocols and processes.
2. Coordinate the activities related to maintaining critical infrastructure protection.
3. Establish reliability assurance processes and documentation related to planning and operations within the Reliability Assurer's area including such things as a regional reliability plan or a Reliability Coordinator plan.
4. Identify and address gaps in reliability processes and responsibilities.



Functional Entity — Reliability Assurer

Definition

The functional entity that monitors and evaluates the activities related to planning and operations, and coordinates activities of functional entities to secure the reliability of the Bulk Electric System within a Reliability Assurer area and adjacent areas.



Relationships with Other Functional Entities

1. Coordinates reliability assurance activities of the functional entities within the Reliability Assurer area.
2. Coordinates reliability assurance activities with adjacent Reliability Assurers.
3. Coordinates critical infrastructure protection programs with functional entities.
4. Collects information from functional entities related to Reliability Assurance processes.

Function — Planning Reliability



Tasks

1. Develop and maintain methodologies for the analysis and simulation of the transmission systems in the evaluation and development of transmission expansion plans and the analysis and development of resource adequacy plans.
2. Define information required for planning purposes, and facilitate the process for consolidating and collecting or developing such information, including:
   a. Transmission facility characteristics and ratings.
   b. Demand and energy forecasts, capacity resources, and demand response programs.
   c. Generator unit performance characteristics and capabilities.
   d. Long-term capacity purchases and sales.
3. Evaluate, develop, document, and report on resource and transmission expansion plans for the Planning Coordinator area. Integrate the respective plans, evaluate the impact of those plans on and by adjoining Planning Coordinator's integrated plans and assess whether the integrated plan meets reliability needs, and, if not, then to report on potential transmission system and resource adequacy deficiencies and suggest or facilitate the process for developing alternative plans to mitigate identified deficiencies.
   a. Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for transmission service.
   b. Review transmission facility plans required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.
   c. Review and determine transfer capability (generally one year and beyond) as appropriate.
   d. Monitor and evaluate transmission expansion plan and resource plan implementation.
   e. Coordinate projects requiring transmission outages that can impact reliability and firm transactions.
4. Coordinate with adjoining Planning Coordinators so that system models and resource and transmission expansion plans take into account modifications made to adjacent Planning Coordinator areas.
5. Develop and maintain transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy.

Functional Entity — Planning Coordinator

Definition
The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.

Introduction to the Planning Coordinator
The Planning Coordinator is responsible for assessing the longer-term reliability of its Planning Coordinator area. While the area under the purview of a Planning Coordinator may include as few as one Transmission Planner and one Resource Planner, the Planning Coordinator's scope of activities may include extended coordination with integrated Planning Coordinators' plans for adjoining areas beyond individual system plans. By its very nature, Bulk Electric System planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems. Planning Coordinators work through a variety of mechanisms to conduct facilitated, coordinated, joint, centralized, or regional planning activities to the extent that all network areas with little or no ties to others' areas, such as interconnections, are completely coordinated for planning activities.



Relationships with Other Functional Entities

1. Coordinates and collects data for system modeling from Transmission Planner, Resource Planner, and other Planning Coordinators.
2. Coordinates transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators.
3. Coordinates plans with Reliability Coordinator and other Planning Coordinators on reliability issues.
4. Receives plans from Transmission Planners and Resource Planners.
5. Collects information including:
    a. Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.
    b. Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners.
    c. Generator unit performance characteristics and capabilities from Generator Owners.
    d. Long-term capacity purchases and sales from Transmission Service Providers.
6. Collects and reviews reports on transmission and resource plan implementation from Resource Planners and Transmission Planners.

7. Submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Planning Coordinator area with Transmission Planners and Resource Planners and adjacent Planning Coordinator areas, as appropriate.
8. Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system.
9. Facilitates the integration of the respective plans of the Resource Planners and Transmission Planners within the Planning Coordinator area.
    a. Reviews the integrated plan with respect to established reliability needs considering the impact on and by adjoining systems.
    b. In coordination with the Resource Planners and Transmission Planners, facilitates the development of alternative solutions for plans that do not meet those reliability needs.

Function — Transmission Planning

Tasks

1. Maintain and develop, in cooperation with adjacent and overlapping Transmission Planners, methodologies and tools for the analysis and simulation of the transmission systems in the evaluation and development of transmission expansion plans related to resource adequacy plans.
2. Define, consolidate and collect or develop, in cooperation with adjacent and overlapping Transmission Planners, information required for planning purposes including:
   a. Transmission facility characteristics and ratings.
   b. Demand and energy forecasts, capacity resources, and demand response programs.
   c. Generator unit performance characteristics and capabilities.
   d. Long-term capacity purchases and sales
3. Maintain transmission system models (steady state, dynamics, and short circuit) to evaluate Bulk Electric System performance.
4. Coordinate with adjacent and overlapping Transmission Planners so that system models and resource and transmission expansion plans take into account modifications made to adjacent and overlapping Transmission Planner areas.
5. Evaluate, develop, document, and report on expansion plans for the Transmission Planner area. Assess whether the integrated plan meets reliability needs, and, if not, report on potential network conditions or configurations that do not meet performance requirements and provide potential alternative solutions to meet performance requirements.
   a. Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for transmission service.
   b. Evaluate and plan for all requests required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.
   c. Determine transfer capability values (generally one year and beyond) as appropriate.
   d. Monitor, evaluate and report on transmission expansion plan and resource plan implementation.
   e. Coordinate projects requiring transmission outages that can impact reliability and firm transactions.
6. Notify Generation Owners, Resource Planners, Transmission Planners and Transmission Owners of any planned transmission changes that may impact their facilities.
7. Define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.



Functional Entity — Transmission Planner

Definition
The functional entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a Transmission Planner area.



Introduction to the Transmission Planner
The Transmission Planner is responsible for assessing the longer-term (generally one year and beyond) reliability of its Transmission Planner area. By its very nature, Bulk Electric System planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems. Transmission Planners coordinate their plans with the adjoining Transmission Planners to assess impact on or by those plans. The area under the purview of a Transmission Planner may include one or more Resource Planner areas and overlap one or more adjacent Transmission Planners.

Relationships with Other Functional Entities

1. Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, Resource Planners, other Transmission Planners, Transmission Owners, and Transmission Service Providers.
2. Collects information including:
    a. Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.
    b. Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners.
    c. Generator unit performance characteristics and capabilities from Generator Owners.
    d. Long-term transmission capacity purchases and sales from Transmission Service Providers
3. Informs Resource Planners and other Transmission Planners of the methodologies and tools for the simulation of the transmission system.
4. Coordinates with Resource Planners and other Transmission Planners on Bulk Electric System expansion plans.
5. Coordinates the evaluation of Bulk Electric System expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.
6. Reports on and coordinates its Bulk Electric System expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

7. Notifies other Transmission Planners, Transmission Owners, Transmission Operators and other entities that may be impacted of any planned Bulk Electric System changes.
8. Coordinates with Distribution Providers, Transmission Owners, Generator Owners and Load-Serving Entities in the evaluation and plans for all requests required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.
9. Submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Transmission Planner area with other Transmission Planners and Resource Planners, as appropriate.
10. Coordinates and develops transfer capability values with other Transmission Planners, Reliability Coordinators, Transmission Operators, Transmission Owners and Transmission Service Providers
11. Coordinates with Transmission Owners and Generator Owners to define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.
12. Receives maintenance schedules and construction plans from Transmission Operator or Transmission Owner for input into and evaluation of Bulk Electric System expansion plans.

Function — Resource Planning

Tasks

1. Consider generation capacity from resources both within and outside of the Resource Planner area for assessing resource adequacy..
2. Monitor and report, as appropriate, on its resource plan implementation.
3. Develop and maintain resource (demand and capacity) models to evaluate resource adequacy.
4. Collect or develop information required for resource adequacy purposes, including:
   a. demand and energy forecasts, capacity resources, and demand response programs,
   b. generator unit performance characteristics and capabilities, and
   c. long-term capacity purchases and sales and
   d. transmission (interface) limits.
5. Evaluate, develop, document, and report on a resource adequacy plan for its portion of the Transmission Planner and Planning Coordinator area.
6. Assist in the evaluation of the deliverability of resources.



Functional Entity — Resource Planner

Definition

The functional entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Resource Planner area.



Relationships with Other Functional Entities

1. Coordinates the resource models with its Planning Coordinator.
2. Coordinates with Transmission Owners and Transmission Planners on the deliverability of resources to customers.
3. Coordinates with and collects data for resource planning from the Load-Serving Entities, Generator Owners, Generator Operators, Transmission Planners, Transmission Operators, Interchange Coordinators, and Reliability Assurers.
4. Coordinates with Transmission Planners, Transmission Service Providers, Reliability Coordinators, and Planning Coordinators on resource adequacy plans.
5. Coordinates with adjoining Resource Planners within the Planning Coordinator area to avoid the double-counting of resources.
6. Reports its resource plan to the Transmission Planner and Planning Coordinator for evaluation and compliance with Reliability Standards.
7. Reports on resource plan implementation to the Transmission Planner, Planning Coordinator and Reliability Assurer.
8. Works with the Planning Coordinator and Transmission Planners to identify potential alternative transmission solutions to meet Resource Planner plans.
9. Applies methodologies and tools for the analysis and development of resource adequacy plans from the Planning Coordinator.

Function — Reliability Operations



Tasks

1. Monitor all reliability-related parameters within the reliability area, including generation dispatch and generation/transmission maintenance plans.
2. Identify, communicate, and direct actions if necessary to relieve reliability threats and limit violations in the reliability area.
3. Develop Interconnection Reliability Operating Limits (to protect from instability and Cascading).
4. Assist in determining reliability-related services requirements for balancing generation and load, and transmission reliability (e.g., reactive requirements, location of operating reserves).
5. Perform reliability analysis (actual and contingency) for the reliability area.
6. Direct revisions to transmission maintenance plans as permitted by agreements.
7. Direct revisions to generation maintenance plans as permitted by agreements.
8. Direct implementation of emergency procedures including load shedding.
9. Direct and coordinate system restoration.
10. Curtail Confirmed Interchange that adversely impacts reliability.

Functional Entity — Reliability Coordinator

Definition
The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.



Introduction to the Reliability Coordinator
The Reliability Coordinator maintains the Real-time operating reliability of its Reliability Coordinator Area and in coordination with its neighboring Reliability Coordinator's wide-area view. The wide-area view includes situational awareness of its neighboring Reliability Coordinator Areas. Its scope includes both transmission and balancing operations, and it has the authority to direct other functional entities to take certain actions to ensure that its Reliability Coordinator Area operates reliably.

Transmission operations. With respect to transmission operations, the Reliability Coordinator and Transmission Operator have similar roles, but different scopes. The Transmission Operator directly maintains reliability for its own defined area. However, the Reliability Coordinator also maintains reliability, in concert with the other Reliability Coordinators, for the Interconnection as a whole. Thus, the Reliability Coordinator needs a "wide-area" view that reaches beyond its boundaries to enable it to operate within Interconnection Reliability Operating Limits. The Transmission Operator may or may not have this "wide- area" view, but the Reliability Coordinator does have it. The Reliability Coordinator may direct a Transmission Operator within its Reliability Coordinator Area to take whatever action is necessary to ensure that Interconnection Reliability Operating Limits are not exceeded.

Balancing operations. The Reliability Coordinator ensures that the generation-demand balance is maintained within its Reliability Coordinator Area, which, in turn, ensures that the Interconnection frequency remains within acceptable limits. The Balancing Authority has the responsibility for generation-demand-interchange balance in the Balancing Authority Area. The Reliability Coordinator may direct a Balancing Authority within its Reliability Coordinator Area to take whatever action is necessary to ensure that this balance does not adversely impact reliability.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinates with other Reliability Coordinators, Transmission Planners, and Transmission Service Providers on transmission system limitations.
2. Receives facility and operational data from Generator Operators, Load-Serving Entities, Transmission Owners, Generator Owners, and Transmission Operators.
3. Receives generation dispatch from Balancing Authorities and issues dispatch adjustments to Balancing Authorities to prevent exceeding limits within the Reliability Coordinator Area (if not resolved through market mechanisms).

4. Receives integrated operational plans from Balancing Authorities for reliability analysis of Reliability Coordinator Area.
5. Receives transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis.
6. Develops Interconnection Reliability Operating Limits, based on Transmission Owners' and Generator Owners' specified equipment ratings, and provides them to Transmission Operators.
7. Assists Transmission Operators in calculating and coordinating System Operating Limits.
8. Provides reliability analyses to Transmission Operators, Generator Operators and Balancing Authorities in its area as well as other Reliability Coordinators.
9. Directs Generator Owners and Transmission Owners to revise generation and transmission maintenance plans that are adverse to reliability.
10. Receives balancing information from Balancing Authorities for monitoring.
11. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.
12. Provide IROLs and TTC to the Transmission Service Provider for ATC calculation.
13. Develops operating agreements or procedures with Transmission Owners.
14. Coordinates with Transmission Operators on system restoration plans, contingency plans and reliability-related services.

Real Time

15. Coordinates reliability processes and actions with and among other Reliability Coordinators.
16. Receives Real-time operational information from Balancing Authorities, Interchange Coordinators and Transmission Operators for monitoring.
17. Issues reliability alerts to Generator Operators, Transmission Operators, Transmission Service Providers, Balancing Authorities, Interchange Coordinators, Regional Entities and NERC.
18. Issues corrective actions and emergency procedures directives (e.g., curtailments or load shedding) to Transmission Operators, Balancing Authorities, Generator Operators, Distribution Providers, and Interchange Coordinators.
19. Specifies reliability–related requirements (e.g., reactive requirements, location of operating reserves) to Balancing Authorities.
20. Receives verification of emergency procedures from Balancing Authorities.
21. Receives notification of Confirmed Interchange changes from Balancing Authorities.
22. Orders redispatch of generation by Balancing Authorities.
23. Directs use of flow control devices by Transmission Operators.
24. Responds to requests from Transmission Operators to assist in mitigating equipment overloads.

Function — Balancing

Tasks



1. Control any of the following combinations within a Balancing Authority Area:
   a. Load and generation (an isolated system)
   b. Load and Confirmed Interchange
   c. Generation and Confirmed Interchange
   d. Generation, load, and Confirmed Interchange
2. Calculate area control error within the reliability area.
3. Operate in the Balancing Authority Area to maintain load-interchange-generation balance.
4. Review generation commitments, dispatch, and load forecasts.
5. Formulate an operational plan (generation commitment, outages, etc.) for reliability evaluation.
6. Approve Arranged Interchange from ramping ability perspective.
7. Implement Confirmed Interchange.
8. Operate the Balancing Authority Area to contribute to Interconnection frequency.
9. Monitor and report control performance and disturbance recovery.
10. Provide balancing and energy accounting (including hourly checkout of Confirmed Interchange, Implemented Interchange and actual interchange), and administer inadvertent energy paybacks.
11. Determine needs for reliability-related services.
12. Deploy reliability-related services.
13. Implement emergency procedures.

Functional Entity — Balancing Authority

Definition
The functional entity that integrates resource plans ahead of time, maintains generation-load-interchange-balance within a Balancing Authority Area, and contributes to Interconnection frequency in real time.



Relationships with Other Functional Entities

Ahead of Time

1. Receives operating and availability status of generating units and operational plans and commitments from Generator Operators (including annual maintenance plans) within the Balancing Authority Area.
2. Receives annual maintenance plans from Generator Owners within the Balancing Authority Area.
3. Receives reliability evaluations from the Reliability Coordinator.
4. Receives final approval or denial of a request for an Arranged Interchange from the Interchange Coordinators.
5. Compiles load forecasts from Load-Serving Entities.
6. Develops agreements with adjacent Balancing Authorities for ACE calculation parameters.
7. Submits integrated operational plans to the Reliability Coordinator for reliability evaluation and provides balancing information to the Reliability Coordinator for monitoring.
8. Confirms Arranged Interchange with Interchange Coordinators.
9. Confirms ramping capability with Interchange Coordinators.
10. Implements generator commitment and dispatch schedules from the Load-Serving Entities and Generator Operators who have arranged for generation within the Balancing Authority Area.
11. Acquires reliability-related services from Generator Operator.
12. Receives dispatch adjustments from Reliability Coordinators to prevent exceeding limits.
13. Receives generator information from Generator Owners including unit maintenance schedules and retirement plans.
14. Receives information from Load Serving Entities on self-provided reliability-related services.
15. Coordinates system restoration plans with Transmission Operator.
16. Provides generation dispatch to Reliability Coordinators..

Real Time

17. Coordinates use of controllable loads with Load-Serving Entities (i.e., interruptible load that has been bid in as a reliability-related service or has agreed to participate in voluntary load shedding program under resource/reserve deficiency situations).
18. Receives loss allocation from Transmission Service Providers (for repayment with in-kind losses).
19. Receives Real-time operating information from the Transmission Operator, adjacent Balancing Authorities and Generator Operators.
20. Receives operating information from Generator Operators.
21. Provides Real-time operational information for Reliability Coordinator monitoring.
22. Receives reliability alerts from Reliability Coordinator.
23. Complies with reliability-related requirements (e.g., reactive requirements, location of operating reserves) specified by Reliability Coordinator.
24. Verifies implementation of emergency procedures to Reliability Coordinator.
25. Informs Reliability Coordinator and Interchange Coordinators of Confirmed Interchange changes (e.g., due to generation or load interruptions) involving its Balancing Authority Area.
26. Directs resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in real time.
27. Directs Transmission Operator (or Distribution Provider) to reduce voltage or shed load if needed to ensure balance within its Balancing Authority Area.
28. Directs Generator Operators to implement redispatch for congestion management as directed by the Reliability Coordinator.
29. Implements corrective actions and emergency procedures as directed by the Reliability Coordinator.
30. Implements system restoration plans as directed by the Transmission Operator.
31. Directs Transmission Operator to implement flow control devices.
32. Receives information of Implemented Interchange and Confirmed Interchange curtailments from Interchange Coordinator.

After the hour

33. Confirms Implemented Interchange with Confirmed Interchange provided by the Interchange Coordinators after the hour for “checkout.”
34. Confirms Implemented Interchange and Confirmed Interchange with adjacent Balancing Authorities after the hour for “checkout.”

Function — Market Operations

The Market Operations function, its tasks, and the interrelationships with other entities are included in the Functional Model only as an interface point of reliability Functions with commercial functions.



Functional Entity — Market Operator (Resource Integrator)

Definition

The market entity whose interrelationships with other entities are included in the Functional Model only as an interface point of reliability functions with commercial functions.



Relationships with Other Functional Entities

Market Operator tasks and relationships are specific to a particular market design and will depend on the market structure over which the Market Operator presides.

Function — Transmission Operations

Tasks



1. Monitor and provide telemetry (as needed) of all reliability-related parameters within the reliability area.
2. Monitor the status of, and deploy, facilities classed as transmission assets, which may include the transmission lines connecting a generating plant to the transmission system, associated protective relaying systems and Special Protection Systems.
3. Develop system limitations such as System Operating Limits and Total Transfer Capabilities, and operate within those limits.
4. Develop and implement emergency procedures.
5. Develop and implement system restoration plans.
6. Operate within established Interconnection Reliability Operating Limits.
7. Perform reliability analysis (actual and contingency) for the Transmission Operator Area.
8. Adjust flow control devices within the transmission area to maintain reliability.
9. Deploy reactive resources to maintain transmission voltage within defined limits.

Functional Entity — Transmission Operator

Definition
The functional entity that ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area.



Introduction to the Transmission Operator
The Transmission Operator is responsible for the Real-time operating reliability of the transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably.

The Transmission Operator and Reliability Coordinator have similar roles with respect to transmission operations, but different scopes. The Transmission Operator scope is narrower than the Reliability Coordinator, and the Transmission Operator does not necessarily "see" very far beyond its own boundaries. Therefore, the Transmission Operator can calculate System Operating Limits, but will not necessarily calculate Interconnection Reliability Operating Limits, which requires the wider scope of the Reliability Coordinator.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinates restoration plans with Reliability Coordinator, Transmission Operators, Balancing Authorities, and Distribution Providers.
2. Receives maintenance requirements and construction plans and schedules from the Transmission Owners and Generation Owners.
3. Receives Interconnection Reliability Operating Limits as established by the Reliability Coordinator.
4. Receives reliability evaluations from the Reliability Coordinator.
5. Develops agreements with adjacent Transmission Operators for joint transmission facilities.
6. Defines Total Transfer Capabilities and System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator.
7. Arranges for reliability-related services from Generator Operators.
8. Develops contingency plans, and monitors operations of the transmission facilities within the Transmission Operator Area control and as directed by the Reliability Coordinator.
9. Provides facility and operating information to the Reliability Coordinator.
10. Provides to the Transmission Planner information on the capability to curtail (reduce) and shed load during emergencies.

11. Provides Total Transfer Capabilities and System Operating Limits to, and coordinates Available Transfer Capability with, Transmission Service Provider.
12. Receives operating and availability status of generating units from Generation Operators including status of automatic voltage regulators.
13. Develops operating agreements or procedures with Transmission Owners.

Real Time

14. Coordinates load shedding with, or as directed by, the Reliability Coordinator.
15. Provides Real-time operations information to the Reliability Coordinator and Balancing Authority.
16. Notifies Generator Operators of transmission system problems (e.g., voltage limitations or equipment overloads that may affect generator operations).
17. Requests Reliability Coordinator to assist in mitigating equipment overloads. (e.g., redispatch, transmission loading relief).
18. Deploys reactive resources from Transmission Owners and Generator Owners to maintain acceptable voltage profiles.
19. Directs Distribution Providers to shed load if needed to ensure reliability within the Transmission Operator Area.
20. Implements flow control device operations for those ties under the Transmission Operator's purview as directed by the Balancing Authorities or Reliability Coordinator.
21. Receives reliability alerts from Reliability Coordinator.
22. Directs Balancing Authorities and Distribution Providers to implement system restoration plans.

Function — Interchange

Tasks



1. Receive an Arranged Interchange.
2. Ensure an Arranged Interchange is balanced and valid (Balancing Authority and Transmission Service Provider validation of sources and sinks, transmission arrangements, reliability-related services, etc.).
3. Coordinate (i.e., collect and consolidate) approval, change, and denial requests for an Arranged Interchange to become Confirmed Interchange. Approvals may be explicit or by exception.
4. Receive confirmations of requested Arranged Interchange.
5. Communicate status of an Arranged Interchange that becomes Confirmed Interchange or otherwise.
6. Communicate Confirmed Interchange information to the appropriate reliability assessment tools (e.g., the interchange distribution calculator in the Eastern Interconnection).
7. Maintain record of an individual Confirmed Interchange.

Functional Entity — Interchange Coordinator

Definition

The functional entity that ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Confirmed Interchange between Balancing Authority Areas.



Relationships with Other Functional Entities

Ahead of Time

1. Receives Arranged Interchange from Purchasing-Selling and Load Serving Entities.
2. Submits request for an Arranged Interchange to become Confirmed Interchange to the Balancing Authorities and Transmission Service Providers for approvals.
3. Receives approval or denial from Transmission Service Providers of transmission arrangement(s) for Arranged Interchange.
4. Receives approval or denial from Balancing Authorities of the ability to meet ramping requirements for submitted Arranged Interchange.
5. Communicates final approval or denial of a request for an Arranged Interchange to become Confirmed interchange to the Reliability Coordinator, Balancing Authorities, Transmission Service Providers and Purchasing-Selling Entities and Load-Serving Entities for implementation and NERC identified reliability analysis services.

Real Time

6. Receives curtailments and redispatch implementation requests from Reliability Coordinators for an Arranged Interchange.
7. Receives information on Confirmed Interchange interruptions from the Balancing Authorities and communicates the Confirmed Interchange status to Balancing Authorities, Transmission Service Providers, Reliability Coordinators, and Purchasing-Selling/Load-Serving Entities.
8. Informs Transmission Service Providers, Purchasing-Selling/Load-Serving Entities, Reliability Coordinators, and Balancing Authorities of Confirmed Interchange revisions (including curtailments).

After the hour

9. Maintains and provides a record of individual Confirmed Interchange for which it coordinated with the Balancing Authorities.
10. Coordinates Confirmed Interchange with Balancing Authorities after the hour for "checkout."

Function — Transmission Service

Tasks

1. Receive transmission service requests and process each request for service according to the requirements of the tariff.
   a. Maintain commercial interface for receiving and confirming requests for transmission service according to the requirements of the tariff (e.g., OASIS).
2. Determine and post available transfer capability values.
3. Approve or deny transmission service requests.
4. Approve Arranged Interchange from transmission service arrangement perspective.
5. Allocate transmission losses (MWs or funds) among Balancing Authority Areas.



Functional Entity — Transmission Service Provider

Definition
The functional entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.



Relationships with Other Functional Entities

Ahead of Time

1. Receives Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits from Planning Coordinator, Transmission Planner, Transmission Operator and Reliability Coordinator, and coordinates Available Transfer Capability with these entities and other Transmission Service Providers.
2. Receives transmission Facility Ratings from Transmission Owners.
3. Receives transmission expansion plans identified by the Planning Coordinator to help determine ability to accommodate long-term transmission service requests.
4. Approves or denies transmission service requests from Purchasing-Selling Entities, Generator Owners, and Load-Serving Entities.
5. Confirms validity of transmission service requests indicated in the Arranged Interchange with Interchange Coordinators.
6. Develops agreements or procedures with Transmission Owners.
7. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.

Real Time

8. Receives Confirmed Interchange implementation (including curtailments) from the Interchange Coordinators.
9. Receives reliability alerts from Reliability Coordinator.
10. Provides loss allocation to Balancing Authorities.

Function — Transmission Ownership

Tasks

1. Develop interconnection agreements.
2. Establish ratings of transmission facilities.
3. Maintain transmission facilities and rights-of-way.
4. Design and install owned facilities classified as transmission and obtain associated rights-of-way.
5. Design and authorize maintenance of transmission protective relaying systems and Special Protection Systems.



Functional Entity — Transmission Owner

Definition
The functional entity that owns and maintains transmission facilities.



Relationships with Other Functional Entities

1. Coordinates with Transmission Planners and the Planning Coordinator, Generator Owners, other Transmission Owners, and Load-Serving Entities desiring to connect with the Bulk Electric System.
2. Receives approved transmission expansion plans from the Transmission Planner.
3. Develops agreements or procedures with the Transmission Service Providers.
4. Develops operating agreements or procedures with the Transmission Operators, Reliability Coordinators and Distribution Providers.
5. Develops agreements with adjacent Transmission Owners for joint transmission facilities.
6. Provides transmission expansion plans and changes to the Planning Coordinator and Transmission Planners.
7. Provides transmission Facility Ratings to Transmission Operators, Reliability Coordinators, Transmission Service Providers, Distribution Providers, Transmission Planners, and Planning Coordinator.
8. Provides maintenance and construction plans and schedules to the Reliability Coordinator, Transmission Operator, and Transmission Planner.
9. Develops interconnection agreements with the Distribution Providers and Generation Owners for connecting to the Bulk Electric System.
10. Provides reactive resources to Transmission Operators.
11. Revises transmission maintenance plans as requested by the Reliability Coordinator.

Function — Distribution



Tasks

1. Provide and operate electrical delivery facilities between the transmission system and the End-use Customer.
2. Implement voltage reduction.
3. Design and maintain protective relaying systems, under-frequency load shedding systems, under-voltage load shedding systems, and Special Protection Systems that interface with the transmission system.
4. Provide and implement load-shed capability.
5. Maintain voltage and power factor within specified limits at the interconnection point.

Functional Entity — Distribution Provider



Definition
The functional entity that provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.

Introduction to the Distribution Provider
The Distribution Provider delivers electrical energy to the End-use Customer from the transmission system. For those End-use Customers who are served at transmission voltages, the Transmission Owner may also serve as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. The Distribution Provider provides the switches and reclosers that could be used to shed load for emergency action.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinates with Transmission Planners on transmission expansion.
2. Coordinates system restoration plans with Transmission Operator.
3. Coordinates with End-use Customers and Load-Serving Entities to identify new facility connection needs.
4. Develop interconnection agreements with Transmission Owners on a facility basis.
5. Provides operational data to Transmission Operator.
6. Coordinate with Load-Serving Entities to identify critical loads that are to be precluded from load shedding where avoidable.

Real Time

7. Implements voltage reduction and sheds load as directed by the Transmission Operator or Balancing Authority.
8. Implements system restoration plans as coordinated by the Transmission Operator.
9. Directs Load-Serving Entities to communicate requests for voluntary load curtailment.

Function — Generator Operation

Tasks

1. Formulate daily generation plan.
2. Report operating and availability status of units and related equipment, such as automatic voltage regulators.
3. Operate generators to provide real and reactive power or reliability-related services per contracts or arrangements.
4. Monitor the status of generating facilities.
5. Support Interconnection frequency.



Functional Entity — Generator Operator

Definition
The functional entity that operates generating unit(s) and performs the functions of supplying energy and reliability related services.



Relationships with Other Functional Entities

Ahead of Time

1. Provides generation commitment plans to the Balancing Authority.
2. Provides Balancing Authority and Transmission Operators with requested amount of reliability-related services.
3. Provides operating and availability status of generating units to Balancing Authority and Transmission Operators for reliability analysis.
4. Reports status of automatic voltage or frequency regulating equipment to Transmission Operators.
5. Provides operational data to Reliability Coordinator.
6. Receives reliability analyses from Reliability Coordinator.
7. Receives notice from Purchasing-Selling Entity if Arranged Interchange approved or denied.
8. Receives reliability alerts from Reliability Coordinator.
9. Receives notification of transmission system problems from Transmission Operators.

Real Time

10. Provides Real-time operating information to the Transmission Operators and the required Balancing Authority.
11. Adjusts real and reactive power as directed by the Balancing Authority and Transmission Operators.

Function — Generator Ownership



Tasks

1. Establish generating facilities ratings, limits, and operating requirements.
2. Design and authorize maintenance of generation plant protective relaying systems, protective relaying systems on the transmission lines connecting the generation plant to the transmission system, and Special Protection Systems.
3. Maintains owned generating facilities.
4. Provide verified generating facility performance characteristics / data.

Functional Entity — Generator Owner

Definition
The functional entity that owns and maintains generating units.



Relationships with Other Functional Entities

1. Provides generator information to the Transmission Operator, Reliability Coordinator, Balancing Authority, Transmission Planner, and Resource Planner.
2. Provides unit maintenance schedules and unit retirement plans to the Transmission Operator, Balancing Authority, Transmission Planner, and Resource Planner.
3. Develops an interconnection agreement with Transmission Owner on a facility basis.
4. Receives approval or denial of transmission service request from Transmission Service Provider.
5. Provides reliability related services to Purchasing-Selling Entity pursuant to agreement.
6. Reports the annual maintenance plan to the Reliability Coordinator, Balancing Authority and Transmission Operator.
7. Revises the generation maintenance plans as requested by the Reliability Coordinator.

Function — Purchasing-Selling

Tasks

1. Purchase and sell energy or capacity.
2. Arrange for transmission service that is required by tariffs.
3. Request implementation of Arranged Interchange.



Functional Entity — Purchasing-Selling Entity

Definition

The functional entity that purchases or sells, and takes title to, energy, capacity, and reliability related services.



Relationships with Other Functional Entities

Ahead of Time

1. Arranges for transmission service from Transmission Service Providers and makes arrangements for reliability-related services with Generator Owners or Load-Serving Entities.
2. Submits Requests For Interchange to Interchange Coordinators.
3. Notifies Generator Operators and Load-Serving Entities if Arranged Interchange requests are approved or denied.
4. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.
5. Receives load profiles and forecasts from Load-Serving Entities.

Real Time

6. Notifies Interchange Coordinators of Confirmed Interchange and Implemented Interchange cancellations or terminations.
7. Receives notice of Confirmed Interchange curtailments from Interchange Coordinator.

Function — Load-Serving

Tasks

1. Collect individual load profiles.
2. Identify capability for and communicate requests for voluntary load curtailment.
3. Participate in under-frequency load shedding systems and under-voltage load shedding systems through identification of critical customer loads that are to be excluded from the load shedding systems.
4. Identify need for facilities and provide capability of self-provided reliability-related services for its load.
5. Develop overall load profiles and forecasts of end-user energy requirements.
6. Acquire necessary transmission service, and reliability-related services.
7. Submits Requests For Interchange to Interchange Coordinators.
8. Manage resource portfolios to meet demand and energy requirements of End-use Customers.



Functional Entity — Load-Serving Entity

Definition

The functional entity that secures energy and transmission service (and reliability related services) to serve the electrical demand and energy requirements of its end use customers.



Relationships with Other Functional Entities

Ahead of Time

1. Submits load profiles and characteristics, plans, and forecasts as needed to the Balancing Authorities, Purchasing-Selling Entities, Planning Coordinator, Resource Planners, and Transmission Planners.
2. Identifies new facility connection needs for End-use Customers.
3. Provides generation commitments and dispatch schedules to the Balancing Authority.
4. Provides information as to self-provided reliability-related services to the Balancing Authority.
5. Provides planned purchases to the Resource Planner and Transmission Planner for system modeling and reliability evaluation.
6. Arranges for transmission service from Transmission Service Providers and makes arrangements for reliability-related services with Generator Owners or Load-Serving Entities.
7. Submits Requests For Interchange to Interchange Coordinators.
8. Notifies Generator Operators if Arranged Interchange requests are approved or denied.
9. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.
10. Coordinates with Distribution Provider on identifying new facility interconnection needs.
11. Receives notification from Purchasing-Selling Entity if Arranged Interchange requests approved or denied.

Real Time

12. Receives requests from the Balancing Authority and Distribution Provider for voluntary load curtailment.
13. Communicate requests for voluntary load curtailment to end-use customers as directed by the Balancing Authority and Distribution Provider.
14. Notifies Interchange Coordinators of Confirmed Interchange cancellations or terminations.
15. Receives notice of Confirmed Interchange curtailments from Interchange Coordinator.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Functional Model
Demand Response Functions and Entities
Informal Comment Period Open
February 13, 2012 – March 14, 2012

NERC Stakeholders

Click here for: Demand Response Functions and Entities Project Page[1]

The Functional Model Working Group (FMWG) is seeking industry comment on its "Report on Assessing the Need for Introducing Demand Response Functions and Entities." The report is now available for review and comment on the Demand Response Functions and Entities project page for a **30-day** industry stakeholder review.

Background

In 2008, the FMWG set up a small advisory team to assess the need to create a Demand Response (DR) function and a DR entity. That advisory team concluded that such a function and related functional entity were not justified at that time. The advisory team also suggested that the FMWG reconsider the issue when developing Functional Model Version 5 (FM V5). The advisory team recommended consideration of assigning such functions and responsibilities to functions and entities already defined in the Functional Model.

The FMWG reconsidered the issue in its development of FM V5, and again concluded that there was no justification for defining a DR function and entity. The NERC Planning Committee approved the FM V5 at its December 8-9, 2009 meeting and requested the FMWG reassess the need to include a DR Functional Entity in the Functional Model Version 6.

In response to this request, the FMWG formed a Functional Model Demand Response Advisory Team (FMDRAT) in mid-2010. The FMDRAT assessed a number of key issues related to the role and reliability impacts of DR in the planning and operation horizons. This assessment is summarized in the FMDRAT "Report on Assessing the Need for Introducing Demand Response Functions and Entities to the NERC Reliability Functional Model."

Instructions

Please use this electronic form[2] to submit comments. An off-line, unofficial copy of the comment form for administrative use is available on the project page.

Next Steps

The FMDRAT will consider the comments submitted and revise the report as appropriate. The report will then be presented to the standing committees for comments. The FMDRAT will revise the report as final, and submit it to the FMWG for acceptance and for forwarding to the Standards Committee for approval.

[1] http://www.nerc.com/filez/standards/Demand_Response_Functions_and_Entities.html
[2] https://www.nerc.net/nercsurvey/Survey.aspx?s=5b53a4f2e2cc4ba092c69ccb381772a1

For more information or assistance, please contact Kristin Iwanechko (via email) or at (404) 446-9736 or Wendy Kinnard (via email) or at (404) 446-9735.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Reliability Standards Announcement

Comment Period Open for BAL-002-WECC-1
January 6 – February 20, 2012

Regional Project: Now available

Proposed Standard for the Western Electricity Coordinating Council (WECC)
WECC has requested NERC to post regional reliability standard BAL-002-WECC-1 Contingency Reserves for a 45-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 Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the regional standards development page.

Background
On March 26, 2007, NERC submitted WECC-BAL-STD-002-0 to FERC for approval. The purpose of standard was to convert the substance of WECC's Reliability Criteria Agreement, III.A.2. WECC Criterion into an enforceable standard.

On June 8, 2007, FERC approved WECC-BAL-STD-002-0 — subject to specific requested changes — finding the standard was more stringent than the corresponding NERC Reliability Standard BAL-002-0. Specifically, FERC found that WECC's requirement to restore Contingency Reserve within 60 minutes was more stringent than the 90-minute restoration period as set forth in NERC's BAL-002-0.

After making the FERC mandated changes, on March 25, 2009, NERC submitted BAL-002-WECC-1 (nomenclature change) to FERC for approval and requested retirement of WECC BAL-STD-002-0. On October 21, 2010, FERC remanded BAL-002-WECC-1 to NERC under FERC Final Order 740 with instruction for WECC to further development the standard. This standard is the result of the aforementioned proceedings.

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 Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
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Princeton, NJ 08540
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Implementation Plan
BAL-002-WECC-1/ WECC-0083
Contingency Reserves
Version 5

Approvals Required

BAL-002-WECC-1
Contingency Reserve

Background

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Prerequisite Approvals

Targeted for WECC Operating Committee approval March 27-29, 2012.
Targeted for WECC Board of Director's approval June 25, 2012.

Applicable Entities

Balancing Authority

The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group, in which case, the Reserve Sharing Group becomes the responsible entity.

Reserve Sharing Group

The Reserve Sharing Group when comprised of a Source Balancing Authority becomes the Source Reserve Sharing Group.

The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the Sink Reserve Sharing Group.

Conforming Changes to Other Standards

None required. BAL-002-WECC-1 is designed to replace BAL-STD-002-0.

Effective Date

On the first day of the third quarter after receipt of applicable regulatory approval.

Justification

BAL-002-WECC-1 may require execution of contracts by some entities before implementation can occur. In response to comments and requests from the field, the team opted for the above Effective Date as a means to allow applicable entities to finalize needed agreements and to retool software as needed.

Consideration of Early Compliance

BAL-002-WECC-1 predominately addresses the amounts of Contingency Reserve required of the applicable entities, based upon three percent of load and three percent of generation. Should the applicable entities opt for early compliance there is no empirical evidence suggesting a decrease in reliability as the amount of Contingency Reserve required under the proposed standard approximates the amount of Contingency Reserve already maintained.

Retirements

BAL-002-WECC-1 is designed to replace BAL-STD-002-0.

Open: ~~November 15, 2011~~January 5, 2012 WECCClosed: ~~December 15, 2011~~ February 6, 2012

Open: January 6, 2012 NERC Closed: February 20, 2012

Completed Actions	Completion Date
1. Post Draft Standard for initial industry comments	September 14, 2007
2. Drafting Team to review and respond to initial industry comments	November 20, 2007
3. Post second Draft Standard for industry comments	November 20, 2007
4. Drafting Team to review and respond to industry comments	January 25, 2008
5. Post Draft Standard for Operating Committee approval	January 25, 2008
6. Operating Committee approved proposed standard	March 6, 2008
7. Post Draft Standard for WECC Board approval	March 1 2, 2008
8. Post Draft Standard for NERC comment period	April 14, 2008
9. WECC Board approved proposed standard	April 16, 2008
10. NERC comment period ended	May 20, 2008
11. Drafting Team completes review and consideration of NERC industry comments	May 30, 2008
12. NERC Board approved the request; Request FERC approval	June 2008
13. Posting 1	January 17, 2011
14. Posting 1 Responses to Comments	March 21, 2011
15. Posting 2 Posted	March 11, 2011
16. Posting 2 Responses to Comments	April 14, 2011
17. OC Special Vote – Failed	May 19, 2011
18. Posting 3	September 19, 2011
19. Posting 3 Responses to Comments	November 15, 2011
20. Posting 4	November 15, 2011
21. Technical Conference / SLC	December 5, 2011
22. Team finalizes Version 4 Responses and Version 5 for posting	January 4, 2012

Open: ~~November 15, 2011~~January 5, 2012 WECCClosed: ~~December 15, 2011~~ February 6, 2012

Open: January 6, 2012 NERC Closed: February 20, 2012

~~22.~~23. Posting 4 Responses to Comments	January 4, 2012
24. Posting 5 at WECC for 30 days	January 5, 2012
25. Posting 5 at NERC for 45 days	January 6, 2012
26. Posting 5 WECC closes	February 6, 2012
27. Posting 5 NERC closes	February 20, 2012
28. Team meets to decide whether to forward to OC	February 23, 2012
29. Notice to OC for March agenda	February 24, 2012
30. Operating Committee approval	March 27, 2012

Open: ~~November 15, 2011~~January 5, 2012 WECCClosed: ~~December 15, 2011~~ February 6, 2012

Open: January 6, 2012 NERC Closed: February 20, 2012

Version History – Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	January 17, 2011	Draft Version of Permanent Replacement Standard for BAL-STD-002-0	Version 1 posted 1/17/2011 through 3/3/2011.
1	March 11, 2011	"Purpose" adjusted, reserve restoration window adjusted, calculation moved to the Measures	Version 2 posted 3/11-2011 through 4/11/2011.
1	September 19, 2011	Post-OC rejection	Version 3 posted 9/19/2011 through ~~October~~ 10/19~~,~~ /2011.
1	November 15, 2011	Structure changed for clarity, added Applicable Entities earlier omitted	Version 4 posted 11/15/2011 through 12/15/2011.
1	January 5, 2012	Structure changed for clarity, added Applicable Entities earlier omitted, responded to technical conference, comments and NERC quality review	Version 5 posted 1/5/2012 through 2/6/2012

Open: ~~November 15, 2011~~January 5, 2012 WECCClosed: ~~December 15, 2011~~ February 6, 2012

Open: January 6, 2012 NERC Closed: February 20, 2012

A. Introduction

1. **Title:** **Contingency Reserve**

2. **Number:** BAL-002-WECC~~-~~1

3. **Purpose:** To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions.

4. **Applicability:**

4.1 Balancing Authority

~~4.2~~ 4.1.1. The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group ~~(Balancing Authorities may meet the requirements of BAL-002-WECC-1 through participation~~, in ~~a~~which case, the Reserve Sharing Group~~).~~ becomes the responsible entity.

4.2 Reserve Sharing Group

4.2.1. The Reserve Sharing Group when comprised of a Source Balancing Authority becomes the source Reserve Sharing Group.

4.2.2. The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the sink Reserve Sharing Group.

~~5.~~ 5. **Effective Date:** On the first day of the third quarter ~~after receipt of~~ following applicable regulatory approval.

B. ~~B.~~ Requirements and Measures

R1. Each Balancing Authority ~~that is not a member of a Reserve Sharing Group~~ and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, ~~based on real-time hourly generating energy values, that is fully deployable~~except within ~~10~~the first sixty minutes~~, in a minimum reserve amount~~ following an event requiring the activation of Contingency Reserve, that is ~~the greater of that specified in Requirement 1, Section 1.1 below (excluding Qualifying Facilities (18 C.F.R.§ 292.101) as addressed in FERC Order 464), comprised of any combination of the reserve types specified in Requirement 1, Section 1.2~~

below. *[*: *Violation Risk Factor: Medium**High**] [Time Horizon: Real-time operations]*

1.1 Minimum Reserve Amount The greater of either:

- AnThe amount of Contingency Reserve equal to the loss of the most severe single contingency; or
- AnThe amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

1.2 Reserve Types

1.2 Comprised of any combination of the reserve types specified below:

- Operating Reserve – Spinning
- Operating Reserve - Supplemental
- Interchange Transactions designated by the sourceSource Balancing Authority as Operating Reserve – Supplemental
- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service.
- A resource, other than generation or load, that can be deployed within ten minutes.provide energy or reduce energy consumption
- Load, including Demanddemand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.
- All other Loadload, not identified above, once the Reliability Coordinator has declared an Energy Emergency Alert energy emergency alert signifying that firm load interruption is imminent or in progress.

1.3 Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).

- **1.4** An amount of capacity from a resource that is deployable within ten minutes.

M1. Evidence of compliance with Requirement 1 may include, but is not limited to, Each Balancing Authority and each Reserve Sharing Group will have documentation that the reservesdemonstrating its Contingency Reserve was

maintained to comply with Requirement 1, Section 1.1 are fully deployable within 10 minutes of notification.

M1. Section 1.1

Evidence of compliance with Requirement 1, Section 1.1 may include, but is not limited to, documentation that reserves were maintained in an amount that is the greater of the two amounts specified in Requirement 1, Section 1.1, based upon data averaged over each clock hour, except within the first 60sixty minutes following an event requiring the activation of Contingency Reserves. *[Violation Risk Factor: Medium] [Time Horizon: Real-time operations]* Reserve.

Part 1.1

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates its Contingency Reserve was maintained in accordance with the amounts identified in Requirement R1, Part 1.1, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Attachment A is a practical illustration showing how the generation amount ismay be calculated under Requirement R1.

- For purposes ofWhere Dynamic Schedules are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement 1, SectionR1, Part 1.1 may include, but is not limited to, documentation showing a reciprocal acknowledgement as to which entity is carrying the reserves. This transfer may be all or some portion of the physical generator and is not limited to the entire physical capability of the generator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time operations]*

- For purposes of Where Pseudo-Ties are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement 1, SectionR1, Part 1.1, may include, but is not limited to, documentation accounting for the transfertransfers included in the Pseudo-tie. *[Violation Risk Factor: Medium] [Time Horizon: Real-time operations*Ties.

M1. SectionPart 1.2

Evidence ofEach Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement 1, SectionR1,

Part 1.2. Evidence may include, but is not limited to documentation that reserves were comprised of the types listed in Requirement ~~1, Section~~R1, Part 1.2 for purposes of meeting the Contingency Reserve obligation of Requirement ~~1. *[Violation Risk Factor: Medium] [Time Horizon: Real-time operations]*~~R1. Additionally, for purposes of the last bullet of Requirement R1, Part 1.2, evidence of compliance may include, but is not limited to, documentation that the reliability coordinator had issued an energy emergency alert, indicating that firm Load interruption was imminent or was in progress.

Part 1.3

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.3. Evidence of compliance with Requirement R1, Part 1.3 may include, but is not limited to documentation that Contingency Reserve amounts are based upon load and generating data averaged over each Clock Hour and excludes Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464.

Part 1.4

Evidence of compliance with Requirement R1, Part 1.4 may include, but is not limited to, documentation that the reserves maintained to comply with Requirement R1, Part 1.4 are fully deployable within ten minutes.

R2. Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as Operating Reserve – Spinning that meets both of the following reserve characteristics. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

2.1 Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;

2.2 Reserve that is capable of fully responding within ten minutes.

M2. Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates it maintained at least half of the Contingency Reserve identified in Requirement R1 as Operating Reserve – Spinning, averaged over each Clock Hour, that met both of the reserve characteristics identified in Requirement R2, Part 2.1 and Requirement R2, Part 2.2.

R3. Each Sink Balancing Authority ~~shall carry~~and each sink Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum ~~reserve amount identified~~Contingency Reserve in Requirement ~~1 above~~R1, equal to the amount of Operating Reserve~~ – –~~Supplemental for any Interchange Transaction

designated as part of the Source Balancing Authority's Operating Reserve~~ –~~ Supplemental~~.~~ or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve. *[Violation Risk Factor: ~~Medium~~High] [Time Horizon: Real-time operations]*

~~**M2.** Evidence of compliance with Requirement 2 may include, but is not limited to documentation that each~~ **M3.** Each Sink Balancing Authority and each sink Reserve Sharing Group will have dated documentation demonstrating it maintained ~~additional reserves in an amount that is~~an amount of Operating Reserve, in addition to the Contingency Reserve identified in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or ~~greater than that specified in Requirement 2, based upon data averaged over each clock hour~~source Reserve Sharing Group's Operating Reserve–Supplemental, for the entire period of the transaction, except within the first ~~60~~sixty minutes following an event requiring the activation of Contingency Reserves~~.~~, in accordance with Requirement 3.

~~R3~~R4. Each Source Balancing Authority and each source Reserve Sharing Group shall ~~carry~~maintain an amount of Operating Reserve, in addition to the minimum ~~reserve amount~~Contingency Reserve amounts identified in Requirement ~~1 above~~R1, equal to the amount and type of Operating Reserves for any Operating Reserve transactions for which it is the Source Balancing Authority~~.~~ or source Reserve Sharing Group. *[Violation Risk Factor: ~~Medium~~High] [Time Horizon: Real-time operations]*

~~**M3.** Evidence of compliance with Requirement 3 may include, but is not limited to, documentation that each~~ **M4.** Each Source Balancing Authority and each source Reserve Sharing Group will have dated documentation that demonstrates it maintained an amount of additional ~~reserves in an amount that is equal to or greater than that specified in Requirement 2, based upon data averaged over each clock hour, except within the first 60 minutes following an event requiring the activation of Contingency~~ Operating Reserves~~.~~

~~**R4.** Each Balancing Authority that is not a member of a Reserve Sharing Group and each Reserve Sharing Group shall maintain at least half of the Contingency Reserve~~ identified in Requirement ~~1 as Operating Reserve - Spinning that meets both of the following reserve characteristics: *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*~~

~~**4.1** Reserve that is immediately~~R1, greater than or equal to the amount and ~~automatically responsive to frequency deviations through the action of a governor or other control system,~~

4.2 Reserve that is capable of fully responding within ten minutes.

M4. Evidence of compliance with Requirement 4 may include, but is not limited to, documentation that each Balancing Authority that is not a member of a Reserve Sharing Group and each Reserve Sharing Group maintained at least half of the Contingency Reserve, type of that identified in Requirement 1, as Operating Reserve – Spinning that meets both of the reserve characteristics specified in Requirement 4, Part 4.1 and Part 4.2. 4, for the entire period of the transaction.

C. Compliance

1. Compliance Monitoring Process

~~**1.1 Compliance Monitoring Responsibility**~~

1.1 Compliance Enforcement Authority

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2 Compliance Monitoring ~~Period~~and Assessment Processes:

~~The~~ Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3 Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ~~use one or more of the following methods to assess compliance:~~ask an entity to provide other evidence to show that it was compliant for the full time period since the

last audit.

- ~~Spot check audits conducted anytime with 30 days notice given to prepare -~~ ~~Periodic audit as scheduled by the Compliance Enforcement Authority –~~ ~~Investigations.~~
- ~~Other methods as provided for in the Compliance Monitoring Enforcement Program.~~

~~**1.2.1** Compliance Monitoring Period: one clock hour.~~

~~1.3 Data Retention~~

Each Balancing Authority and each Reserve Sharing ~~Groups and Balancing Authorities~~Group shall keep evidence for ~~Measure M1~~Requirement R1 through ~~M4~~R4 for three years plus calendar current~~, or since the last audit, whichever is longer~~.

1.4. Additional Compliance Information

1.4.1. This Standard shall apply to each Balancing Authority ~~that is not a member of a Reserve Sharing Group~~ and each Reserve Sharing Group that has registered with WECC as provided in Part 1.4.2 of Section ~~1.4.2 below~~C.

Each Balancing Authority identified in the registration with WECC as provided in Part 1.4.2 of Section ~~1.4.2 below~~C shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

1.4.2. A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC: 1) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, 2) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and 3) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

1.4.3. If an agent properly designated in accordance with Part 1.4.2 of Section ~~1.4.2~~C identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to

each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance: 1) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, 2) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection 1) of this Part 1.4.3 of Section ~~1.4.3~~C, and 3) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection 1) of this Part 1.4.3 of Section ~~1.4.3~~C (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

1.4.4. If an agent properly designated in accordance with Part 1.4.2 of Section ~~1.4.2~~C fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

1.4.5. Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Part 1.4.2 of Section ~~1.4.2~~C shall be subject to this Standard on an individual basis.

Table of Compliance Elements

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	~~High~~~~Medium~~	~~There shall be a Lower Level of non-compliance if there is one hour during a calendar month in which the~~The Balancing Authority or the Reserve Sharing ~~Group's~~Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Contingency Reserve~~.~~ amount, with the characteristics specified in Requirement R1.	~~There shall be a Moderate Level of non-compliance if there is one hour during a calendar month in which the~~The Balancing Authority or the Reserve Sharing ~~Group's~~Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Contingency Reserve~~.~~ amount, with the characteristics specified in Requirement R1.	~~There shall be a High Level of non-compliance if there is one hour during a calendar month in which the~~The Balancing Authority or the Reserve Sharing ~~Group's~~Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Contingency Reserve~~.~~ amount, with the characteristics specified in Requirement R1.	~~There shall be a Severe Level of non-compliance if there is one hour during a calendar month in which the~~The Balancing Authority or the Reserve Sharing ~~Group's~~ Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve amount, with the characteristics specified in Requirement R1.
R2	Real-time Operations	~~Medium~~ High	~~There shall be a Lower Level of non-compliance~~	~~There shall be a Moderate Level of non-~~	~~There shall be a High Level of non-compliance~~	~~There shall be a Severe Level of non-compliance if~~

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~if there is one hour during a calendar month in which the~~The Balancing Authority or the Reserve Sharing ~~Group's~~ Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 100% but greater than or equal to 90% of the required ~~Contingency Reserve.~~Operating Reserve– Spinning amount specified in Requirement R2, and both characteristics were met.	~~compliance if there is one hour during a calendar month in which the~~The Balancing Authority or the Reserve Sharing ~~Group's~~ Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 90% but greater than or equal to 80% of the required ~~Contingency Reserve.~~ Operating Reserve– Spinning amount specified in Requirement R2, and both characteristics were met.	~~if there is one hour during a calendar month in which the~~The Balancing Authority or the Reserve Sharing ~~Group's~~ Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 80% but greater than or equal to 70% of the required ~~Contingency Reserve~~Operating Reserve– Spinning amount specified in Requirement R2, and both characteristics were met.	~~there is one hour during a calendar month in which the~~The Balancing Authority or the Reserve Sharing ~~Group's~~ Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 70% of the required ~~Contingency Reserve~~Operating Reserve– Spinning amount specified in Requirement R2, and both characteristics were met.
R3	Real-time Operations	~~Medium~~ High	~~There shall be a Lower Level of non-compliance if there is one~~	~~There shall be a Moderate Level of non-compliance if~~	~~There shall be a High Level of non-compliance if there is one~~	~~There shall be a Severe Level of non-compliance if there is one hour during a calendar~~

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~hour during a calendar month in which the~~The Balancing Authority or the Reserve Sharing ~~Group's~~ Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required ~~Contingency~~Operating Reserve amount specified in Requirement R3.	~~there is one hour during a calendar month in which the~~The Balancing Authority or the Reserve Sharing ~~Group's~~ Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required ~~Contingency~~Operating Reserve~~.~~ amount specified in Requirement R3.	~~hour during a calendar month in which the~~The Balancing Authority or the Reserve Sharing ~~Group's~~ Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required ~~Contingency~~Operating Reserve amount specified in Requirement R3.	~~month in which the~~The Balancing Authority or the Reserve Sharing ~~Group's~~ Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 70% of the required ~~Contingency~~Operating Reserve amount specified in Requirement R3.
R4	Real-time Operations~~.~~	High	~~There shall be a Lower Level of non-compliance if there is one hour during a calendar month in which the~~The Balancing Authority or the Reserve Sharing ~~Group's~~ Group that incurs one hour, during a	~~There shall be a Moderate Level of non-compliance if there is one hour during a calendar month in which the~~The Balancing Authority or the Reserve Sharing ~~Group's~~ Group that	~~There shall be a The~~High Level ~~of non-compliance if there is one hour during a calendar month in which the~~ Balancing Authority or the Reserve Sharing ~~Group's~~ Group	~~There shall be a Severe Level of non-compliance if there is one hour during a calendar month in which the~~The Balancing Authority or the Reserve Sharing ~~Group's~~ Group that

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			calendar month, in which Contingency Reserve Operating Reserve ~~–~~ ~~Spinning~~ is less than 100% but greater than or equal to 90% of the required Operating Reserve ~~–~~ ~~Spinning;~~ amount specified in Requirement R4.	incurs one hour, during a calendar month, in which Contingency Reserve Operating Reserve ~~–~~ ~~Spinning~~ is less than 90% but greater than or equal to 80% of the required Operating Reserve ~~—~~ ~~Spinning~~amount specified in Requirement R4.	that incurs one hour, during a calendar month, in which Contingency Reserve Operating Reserve ~~–~~ ~~Spinning~~ is less than 80% but greater than or equal to 70% of the required Operating Reserve ~~—~~ ~~Spinning.~~ amount specified in Requirement R4.	incurs one hour, during a calendar month, in which Contingency Reserve Operating Reserve ~~–~~ ~~Spinning~~ is less than 70% of the required Operating Reserve ~~–~~ ~~Spinning.~~ amount specified in Requirement R4.

D. Regional Variances
None.

E. Interpretations
None.

F. Associated Documents
None.

Open: ~~November 15, 2011~~January 5, 2012 WECCClosed: ~~December 15, 2011~~ February 6, 2012

Open: January 6, 2012 NERC Closed: February 20, 2012

Attachment A

Attachment A is illustrative only; it is not a requirement. Requirement R1 calls for an amount of Contingency Reserve to be maintained, predicated on an amount of generation and load required in Requirement R1, Part 1.1., specifically:

> **"1.1** The greater of either:
>
> - The amount of Contingency Reserve equal to the loss of the most severe single contingency;
> - The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation."

Attachment A illustrates one possible way to account for and calculate the amount of generation upon which the Contingency Reserve amount is predicated.

Below is a practical illustration showing how the generation amount ~~is~~may be calculated under ~~R1.~~Requirement R1 for Balancing Authorities (BA) and Reserve Sharing Groups (RSG).

BA1 Generation	**Part of ~~Gen for BAL-002~~Generator ~~Online~~ / RSG 1**	
Generator 1	300 MWs online	Yes
Generator 2	200 MWs online	Yes
Generator 3 (Pseudo-Tied out to BA2)	100 MWs online	No
Generator 4 QF (has ~~Backup Contract~~backup contract)	10 MWs online	No
Generator 5 QF in EMS	10 MWs online	Yes
Generator 6	0 MWs online	Yes
Dynamic Schedule to BA2 ~~Reduces Gen)~~	(~~100~~ from BA1[1]	(50 MWs)
Generation ~~On Line~~	620 MWs	(The sum of gen 1-6)
BA ~~Generation~~generation (EMS)	510 MWs	(The sum of gen 1, 2, and 5)
Generation to use Under BAL-002	~~410~~ WECC-1460 MWs**	(The sum of gen 1, 2 and 5 minus Dynamic Schedule)

[1] Note: This Dynamic Schedule is not the same as the Generator 3 Pseudo-Tie.

Open: November 15, 2011January 5, 2012 WECCClosed: December 15, 2011 February 6, 2012

Open: January 6, 2012 NERC Closed: February 20, 2012

** Assumes BA1 and BA2 agree on Dynamic TransferSchedule treatment. If no agreement, BA1 would have to carrymaintain reserves based on 510 MWs Generation.

BA2

BA2 / RSG2	Generation	Part of Generator
Generator 11	100 MWs	Yes
Generator 12	100 MWs	Yes
Generator 3 (Pseudo-Tied in from BA1)	100 MWs	Yes
Dynamic Schedule from BA1	100 to BA2	50 MWs Yes
BA Generation (EMS)	300 MWs	(The sum of gen 11, 12 and 3.)
Total BA generation (EMS)	300 MWs	(The sum of gen 11, 12 and 3)
Generation to use Under BAL-002	400 MWs** WECC-1	350 MWs** (The sum of gen 11, 12 and 3 plus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic TransferSchedule treatment. If no agreement, BA1 would have to carrymaintain reserves based on 510MWs Generation and BA2 would determine its generation to be 300 MWs.

Guideline and Technical Basis

~~Purpose Statement~~

A Guidance Document addressing implementation of this standard has been filed with this standard.

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2007-12 Frequency Response | Initial Ballot and Non-Binding Poll Results
Date: Monday, December 19, 2011 3:37:23 PM

Standards Announcement

Project 2007-12 Frequency Response

Initial Ballot and Non-Binding Poll Results

Now Available

An initial ballot and non-binding poll of BAL and its implementation plan concluded on December 9, 2011. Voting statistics are listed below, and the Ballot Results webpage provides a link to the detailed initial ballot results.

Initial Ballot Results

Quorum: 93.92%

Approval: 30.82%

Non-Binding Poll Results

89.49% of those who registered to participate provided an opinion or abstention; 37% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Next Steps

The drafting team will consider all comments received during the comment period and ballot.

Background

Frequency Response, a measure of an Interconnection's ability to stabilize frequency immediately following the sudden loss of generation or load, is a critical component to the reliable operation of the bulk power system, particularly during disturbances and restoration. The proposed standard's intent is to collect data needed to accurately analyze existing Frequency Response, set a minimum Frequency Response obligation, provide a uniform calculation of Frequency Bias Settings that transition to values closer to Frequency Response, and encourage coordinated AGC operation. There is evidence of continuing decline in Frequency Response over the past 10 years, but no confirmed reason for the apparent decline. The proposed standard requires entities to provide data so that Frequency Response in each of the Interconnections can be analyzed, and the reasons for the decline in Frequency Response can be identified. Once Frequency Response has been analyzed and confirmed, requirements can be modified to maintain reliability. Additional information is available on the project webpage.

A stakeholder interested in following the Frequency Response Standard Drafting Team's development of BAL-003-1 may monitor meeting agendas and notes on the team's "Related

Files" webpage or may submit a request to join the team's "plus" email list to receive meeting agendas and meeting notes as they are distributed to the team. To join the team's "plus" email list, send a note to sarcomm@nerc.net and include the project's name in the subject line.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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

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From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2009-01 Disturbance and Sabotage Reporting | Initial Ballot and Non-binding Poll Results
Date: Monday, December 19, 2011 3:30:14 PM

Standards Announcement

Project 2009-01 – Disturbance and Sabotage Reporting

Initial Ballot and Non-binding Poll Results

Now Available

An initial ballot of EOP-004-2 – Event Reporting and its implementation plan, and a non-binding poll of the associated VRFs and VSLs, concluded on December 12, 2011. Voting statistics are listed below, and the Ballot Results webpage provides a link to the initial ballot detailed results.

Initial Ballot Results for EOP-004-2

Quorum: 87.97%

Approval: 36.21%

Non-Binding Poll Results

85.28% of those who registered to participate provided an opinion or abstention; 45% of those who provided an opinion indicated support for the VRFs and VSLs.

Next Steps

The drafting team will consider all comments received during the comment period and ballot.

Background

Stakeholders have indicated that identifying potential acts of "sabotage" is difficult to do in real time, and additional clarity is needed to identify thresholds for reporting potential acts of sabotage in CIP-001-1. Stakeholders have also reported that EOP-004-1 has some requirements that reference out-of-date Department of Energy forms, making the requirements ambiguous. EOP-004-1 also has some 'fill-in-the-blank' components to eliminate. The project will include addressing previously identified stakeholder concerns and FERC directives; will bring the standards into conformance with the latest approved version of the ERO Rules of Procedure; and may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. Additional information is available on the project webpage.

A stakeholder interested in following the Disturbance and Sabotage Reporting Drafting Team's development of EOP-004-2 may monitor meeting agendas and notes on the team's "Related Files" web page or may submit a request to join the team's "plus" email list to receive meeting agendas and meeting notes as they are distributed to the team. To join the team's "plus" e-mail list, send an e-mail request to: sarcomm@nerc.net. Please indicate the drafting team's name in the subject line of the e-mail.

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From: Guy V. Zito
To: rscmembers
Subject: CIP Version 5 Standards, Order 706
Date: Friday, December 16, 2011 9:35:50 AM

RSC Members,

Based on the concerns expressed by TFIST and the clarifications they request, NPCC will be casting a vote to reject each of the 10 posted CIP standards. As discussed at the last RSC meeting, I would like the RSC to share their ballot positions with NPCC. The initial ballot period opens today December 16 and closes January 6.

Thanks and Happy Holidays!

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: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2011-INT-01 Revision to MOD-028-1 to Respond to FPL Request for Interpretation
Date: Monday, December 12, 2011 3:30:47 PM

Standards Announcement

Project 2011-INT-01 Revision to MOD-028-1 to Respond to FPL Request for Interpretation

Recirculation Ballot Window Open: December 12 - 22, 2011

Now Available

A recirculation ballot window is now open for revisions to MOD-028-1 – Area Interchange Methodology
through 8 p.m. Eastern on Thursday, December 22, 2011.

In May 2011, FPL requested an interpretation of MOD-028-1, Requirement R3.1. The request asked for clarification of the timing and frequency of TTC calculations needed for ATC calculations. At its July 2011 meeting the Standards Committee approved (with FPL's consent) addressing FPL's request for interpretation through a rapid revision to the MOD-028-1 standard. The interpretation drafting team was appointed as the standard drafting team and directed to submit both a SAR and proposed revisions to MOD-028-1, addressing the issues raised in the request for interpretation. Because the revisions are narrowly focused on addressing the clarification requested by FPL, the Standards Committee approved waiving the initial 30-day formal comment period and directed that the SAR and proposed revisions to the standard be posted for a 45-day parallel comment period and ballot, which ended on November 16, 2011.

Since the initial ballot, the drafting team has considered all comments and made no substantive changes. Only minor changes were made to correct capitalization. No changes were made to the implementation plan.

Documents associated with this project, including clean and redline copies of the standard, the implementation plan (clean only since there were no changes) and the drafting team's consideration of comments submitted during the parallel formal comment period and successive ballot that ended on November 21, 2011, have been posted on the **project page**.

Instructions for Balloting in the Recirculation Ballot
In a recirculation ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their prior votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the recirculation ballot window. If a ballot pool member does not participate in the recirculation ballot, that member's last vote cast in the initial ballot that ended on November 16, 2011 will be carried over.

Members of the ballot pool associated with this project may log in and submit their votes in the recirculation ballots by clicking here: vote.

Next Steps
If the standard and associated implementation plan achieve ballot pool approval, they will be presented to the Board of Trustees for adoption and subsequently filed with regulators for approval.

Standards Development Process

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From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project INT-2011-01 Interpretation of MOD-028-1 for FPL | Recirculation Ballot Results
Date: Tuesday, January 03, 2012 2:03:27 PM

Standards Announcement

Project INT-2011-01 Interpretation of MOD-028-1 for FPL Recirculation Ballot Results

Now Available

A recirculation ballot of MOD-028-2 Area Interchange Methodology and its implementation plan concluded on December 22, 2011. The standard was approved by the ballot pool. Voting statistics are listed below, and the Ballot Results webpage provides a link to the detailed initial ballot results.

Initial Ballot Results
Quorum: 90.10%
Approval: 92.49%

Next Steps
The standard and associated implementation plan will be presented to the NERC Board of Trustees for action, and if adopted, filed with regulatory authorities.

Background
In May 2011, FPL requested an interpretation of MOD-028-1, Requirement R3.1. The request asked for clarification of the timing and frequency of TTC calculations needed for ATC calculations. At its July 2011 meeting the Standards Committee approved (with FPL's consent) addressing FPL's request for interpretation through a rapid revision to the MOD-028-1 standard. The interpretation drafting team was appointed as the standard drafting team and directed to submit both a SAR and proposed revisions to MOD-028-1, addressing the issues raised in the request for interpretation. Because the revisions are narrowly focused on addressing the clarification requested by FPL, the Standards Committee approved waiving the initial 30-day formal comment period and directed that the SAR and proposed revisions to the standard be posted for a 45-day parallel comment period and ballot, which ended on November 16, 2011.

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You have received this email because you are a registered representative in the Registered Ballot Body.

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2009-22 Interpretation of COM-002-2 R2 for ISO/RTO Council | Recirculation Ballot Window Open: December 14-23, 2011
Date: Wednesday, December 14, 2011 11:30:44 AM

Standards Announcement

Project 2009-22 Interpretation of COM-002-2 R2 for ISO/RTO Council

Recirculation Ballot Window Open: December 14-23, 2011

Now Available

A recirculation ballot window is open for Project 2009-22 Interpretation of COM-002-2 R2 for ISO/RTO Council from Wednesday, December 14, 2011 through 8 p.m. Eastern on Friday, December 23, 2011.

Since the initial ballot, the drafting team has considered all comments received during the formal comment period and initial ballot of the interpretation, and made no changes to the interpretation.

Documents associated with this project, including the interpretation, the standard, and the drafting team's consideration of comments submitted during the parallel formal comment period and initial ballot that ended on November 18, 2011, have been posted on the project page.

Instructions for Balloting in the Recirculation Ballots
In a recirculation ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their prior votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the recirculation ballot window. If a ballot pool member does not participate in the recirculation ballot, that member's last vote cast in the successive ballot that ended on November 18, 2011 will be carried over.

Members of the ballot pool associated with the interpretation may log in and submit their votes in the recirculation ballots from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps
If the interpretation achieves ballot pool approval, it will be presented to the Board of Trustees for adoption.

Background
On October 1, 2009, clarification was requested by ISO-RTO Council on Requirement R2, specifically on whether "directives" are limited to actual and anticipated emergency operating conditions, or whether routine operating instructions are also considered "directives." The effort was delayed following discussion with the requester based on the anticipation that more clarity regarding the term, "directives" would be identified through standard development work in Project 2007-02.

When it became clear that the work in Project 2007-02 would require considerable industry debate, a drafting team was formed and prepared a draft interpretation, which was posted for a 30-day formal
comment period that ended December 18, 2010. Reprioritization of the total standards workload in accordance with guidance from the NERC Board of Trustees issued in November 2009 and a delay as the Standards Committee developed more formal processes for addressing interpretations resulted

in a delay in further processing; the Standards Committee directed that work resume on the Interpretation in April 2011.

Additional information on Project 2009-22 is available on the project webpage.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2009-22 – Interpretation of COM-002 R2 for IRC - Recirculation Ballot Results
Date: Tuesday, January 03, 2012 2:03:20 PM

Standards Announcement

Project 2009-22 – Interpretation of COM-002 R2 for IRC

Recirculation Ballot Results

Now Available

A recirculation ballot of an interpretation of COM-002-2 Requirement R2 concluded on December 23, 2011. The interpretation was approved by the ballot pool. Voting statistics are listed below, and the Ballot Results webpage provides a link to the initial ballot detailed results.

Recirculation Ballot Results
Quorum: 92.00%
Approval: 94.58%

Next Steps
The interpretation will be presented to the NERC Board of trustees for action, and if adopted, filed with regulatory authorities.

Background
On October 1, 2009, clarification was requested by ISO-RTO Council on Requirement R2, specifically on whether "directives" are limited to actual and anticipated emergency operating conditions, or whether routine operating instructions are also considered "directives." The effort was delayed following discussion with the requester based on the anticipation that more clarity regarding the term, "directives" would be identified through standard development work in Project 2007-02.

When it became clear that the work in Project 2007-02 would require considerable industry debate, a drafting team was formed and prepared a draft interpretation, which was posted for a 30-day formal comment period that ended December 18, 2010. Reprioritization of the total standards workload in accordance with guidance from the NERC Board of Trustees issued in November 2009 and a delay as the Standards Committee developed more formal processes for addressing interpretations resulted in a delay in further processing; the Standards Committee directed that work resume on the Interpretation in April 2011.

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

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From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2010-07 Generator Requirements at the Transmission Interface
Date: Wednesday, December 14, 2011 12:32:06 PM

Standards Announcement

Project 2010-07
Generator Requirements at the Transmission Interface

Four Recirculation Ballots Window Open: December 14-23, 2011

Now Available

Recirculation ballot windows are open for the four standards listed below from Wednesday, December 14, 2011 through 8 p.m. Eastern on Friday, December 23, 2011.

- FAC-001-1 – Facility Connection Requirements
- Two versions of FAC-003 – Transmission Vegetation Management (FAC-003-3 and FAC-003-X). Note that FAC-003-X shows changes to FAC-003-1, while FAC-003-3 shows changes to FAC-003-2, which was developed by the Project 2007-07 standard drafting team.
- Minor modifications to PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Since the initial ballot, the drafting team has considered all comments received during the formal comment period and initial ballots of the standards. Based on stakeholder comments, the SDT made minor changes to FAC-001-1, FAC-003-X, FAC-003-3, and PRC-004-2.1.

- In FAC-001-1, the SDT corrected a typo in the Applicability section 4.2.1 to change "within" to "with"; corrected a typo in the VSLs for R3 to ensure that parts 3.1.1 through 3.1.16 were referenced, rather than just 3.1.1 through 3.1.6; and changed references to "Transmission System" to "interconnected Transmission systems" to ensure consistency with the language elsewhere in the standard and in FAC-002-1.

- In FAC-003-X and FAC-003-3, the SDT added a clarifying reference to line of sight in the GO exemption in section 4.3.1. of both versions; corrected a typo in 4.3.1.2 of FAC-003-3; and changed "RE" to "Regional Entity" in 4.3.1 of FAC-003-X.

As it discusses in the document titled "Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface," the SDT recognizes that in many cases, generation Facilities are either (1) staffed and the overhead portion is within line of sight or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale

exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.

To clarify the exemption, the SDT has modified the Applicability section 4.3.1 to include an explicit reference to line of sight: "Overhead transmission lines that extend greater than one mile (1.609 kilometers) beyond the fenced area of the generating switchyard or do not have a clear line of sight from the switchyard fence to the point of interconnection and are…"

With this reference, the SDT simply seeks to clarify the exception language based on the intent that has been agreed upon by the stakeholder body. In its Consideration of Comments report from the last formal comment period, which ended on July 17, 2011, the SDT explained, "We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor." With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent and appropriately considered all comments submitted.

Members of the ballot pool should note that the SDT is balloting both FAC-003-3 and FAC-003-X, but stakeholders should not vote as though they are choosing one or the other. The SDT plans to present FAC-003-3 alone to NERC's Board of Trustees, but it wants to have FAC-003-X ready to submit to the Board if, for some reason, neither FAC-003-2 nor FAC-003-3 are approved by FERC. Members of the ballot body should vote on the merits of each version of FAC-003 individually. In other words, stakeholders who support adding Generator Owners to the applicability of FAC-003 should vote in the affirmative for both FAC-003-3 and FAC-003-X.

- In PRC-004-2.1, the SDT added a reference to the generator interconnection Facility to the data retention section of the standard (for consistency with the language in R2) and corrected a typo in the Version History.

Additionally, many commenters encouraged the SDT to reexamine the standards and requirements addressed in FERC's Milford and Cedar Creek orders and NERC staff's draft compliance directive regarding generator lead lines. The SDT reviewed all addressed standards and requirements again and continues to find clear and technical reliability-based reasons that support not adding Generator Owner and Generator Operator requirements to these standards and not requiring the Generator Owner or Generator Operator to register as a Transmission Owner or Transmission Operator. However, to address stakeholder concern, the SDT has expanded its technical justification document (posted under "Supporting Materials") to include any standard or requirement cited by FERC in its Milford/Cedar Creek orders or by NERC in its draft compliance directive.

Documents associated with this project, including clean and redline versions of each standard, implementation plans for each standard (clean only since the SDT made no changes since the last posting), the drafting team's consideration of comments submitted during the parallel formal comment period and initial ballot that ended on November 18, 2011, and supporting materials including two explanatory diagrams and the team's updated technical justification, have been posted on the project page.

Instructions for Balloting in the Recirculation Ballots

In a recirculation ballot, votes are counted by exception. Only members of the ballot pool may

cast a ballot; all ballot pool members may change their prior votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the recirculation ballot window. If a ballot pool member does not participate in the recirculation ballot, that member's last vote cast in the successive ballot that ended on November 18, 2011 will be carried over.

Members of the ballot pool associated with the project may log in and submit their votes in the recirculation ballots from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps
If the standards achieve ballot pool approval, they will be presented to the Board of Trustees for adoption.

Background
The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Facilities, commonly known as generator interconnection Facilities, that are considered by some entities to be transmission, these are most often sole-use Facilities that are not part of the integrated grid. As such, they should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators do affect the overall reliability of the BES. But registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The SDT's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. This can be accomplished by properly applying FAC-001, FAC-003, PRC-004, and later, PRC-005, to Generator Owners as proposed in the redline standards posted for ballot.

Before reviewing the standards, the SDT encourages all stakeholders to read the technical justification resource document posted under "Supporting Materials." This document describes, in great detail, the SDT's rationale for its work thus far. Additional information is available on the project page at http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html

Standards Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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

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From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2010-07 Generator Requirements at the Transmission Interface | Recirculation Ballot Results
Date: Tuesday, January 03, 2012 2:51:35 PM

Standards Announcement

Project 2010-07
Generator Requirements at the Transmission Interface

Recirculation Ballot Results

Now Available

Recirculation ballots for the four standards listed below concluded on December 23, 2011.

- FAC-001-1 – Facility Connection Requirements
- Two versions of FAC-003 – Transmission Vegetation Management (FAC-003-3 and FAC-003-X). Note that FAC-003-X shows changes to FAC-003-1, while FAC-003-3 shows changes to FAC-003-2, which was developed by the Project 2007-07 standard drafting team.
- Minor modifications to PRC-004-2.1 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Voting statistics for each ballot are listed in the table below, and the Ballot Results Webpage provides a link to the detailed results.

Standard	Quorum	Approval
FAC-001-1	88.48%	90.10%
FAC-003-3	87.17%	85.38%
FAC-003-X	86.91%	85.03%
PRC-004-2.1a	86.65%	96.43%

Next Steps

Non-binding polls of the modified VRFs and VSLs will be conducted, and the standards, associated implementation plans, and VRFs and VSLs will be presented to the NERC Board of Trustees for action. If adopted, the standards will be filed with regulatory authorities.

Background

The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Facilities, commonly known as generator interconnection Facilities, that are considered by some entities to be transmission, these are most often sole-use Facilities that are not part of the integrated grid. As such, they should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and

operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators do affect the overall reliability of the BES. But registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The SDT's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. This can be accomplished by properly applying FAC-001, FAC-003, PRC-004, and later, PRC-005, to Generator Owners as proposed in the redline standards posted for ballot.

Before reviewing the standards, the SDT encourages all stakeholders to read the technical justification resource document posted under "Supporting Materials." This document describes, in great detail, the SDT's rationale for its work thus far. Additional information is available on the project page at http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html

Standards Development Process

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From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2007-03 Real-Time Transmission Operations | Formal Comment Period Open Through Jan 12, 2012 | Three Successive Ballot Windows Open January 3 – 12, 2012
Date: Wednesday, December 14, 2011 8:53:48 AM

Standards Announcement

Project 2007-03 Real-Time Transmission Operations
Formal Comment Period Open:
December 14, 2011 – January 12, 2012
Three Successive Ballot Windows Open January 3 – 12, 2012

Available Now

The Real-time Operations Standards Drafting Team has made revisions to three standards and their associated implementation plan in response to stakeholder comments and a quality review:

- TOP-001-2 Coordination of Transmission Operations
- TOP-002-3 Operations Planning
- TOP-003-2 Operational Reliability Data

Clean and redline versions of these standards, the associated implementation plan, and the VRFs and VSLs are posted for a formal 30-day comment period through 8 p.m. Eastern on Thursday, January 12, 2012.

Note that TOP-001-2, TOP-002-3, and TOP-3-2 reflect the merging of the following standards into a single standard, making it impractical to post a "redline" of the three proposed standards that shows the changes to the last balloted versions of these standards. The last approved versions of the standards listed below have been posted on the project's web page for easy reference.

- PER-001-0 Operating Personnel Responsibility and Authority
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2a Normal Operations Planning
- TOP-003-1 Planned Outage Coordination
- TOP-004-2 Transmission Operations
- TOP-005-2 Operational Reliability Information
- TOP-006-2 Monitoring System Conditions

- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-1 Response to Transmission Violations

Instructions for Submitting Comments
Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please note that comments submitted with ballots will use the same form, and it is NOT necessary for ballot pool members to submit two separate sets of comments (one during the comment period and a second with a ballot). Comments submitted with ballots are extremely valuable to help the drafting team revise its work. However, in an effort to reduce the burden on stakeholders providing comments, the drafting team requests that all comments (both those submitted with a ballot and those submitted by stakeholders not balloting) be submitted through the electronic form. This will ensure that stakeholders only provide a single set of comments. Further instructions will be provided in the announcement that the ballot window is open.

Next Steps
Three individual successive ballots (one for each standard) will be conducted beginning on Tuesday, January 3, 2012 and ending at 8 p.m. on Thursday, January 12, 2012. The ballot pool formed for the initial ballot of the three standards will be cloned to create three separate ballot pools, and all members of the original ballot pool will automatically be eligible to vote in the three individual ballots.

The standards are being balloted individually to provide stakeholders an opportunity to cast separate ballots for each standard. The individual ballots will provide the drafting team better feedback on which standards require additional development to achieve stakeholder consensus. Stakeholders are encouraged to consider each standard on its own merits and cast individual ballots, rather than casting the same ballot for all three standards, in order to assist the drafting team with evaluating which standards require additional development to achieve consensus.

Background
The Project 2007-03 drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. The team has also made revisions to address outstanding Order 693 directives.

Standards Development Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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From:	Guy V. Zito
To:	rsballot
Cc:	rsc
Subject:	NPCC Ballot Recommendation and Issues, Project 2007-03 — Real-time Transmission Operations — TOP-001-2, TOP-002-3 and TOP-003-2
Date:	Monday, January 09, 2012 8:01:42 AM
Importance:	High

NPCC Members of the NERC Registered Ballot Body,

The Regional Standards Committee (RSC) has reviewed the subject project currently posted for ballot through 8 pm January 12, 2012. The project involves revision to three standards as indicated above. The RSC has reached a consensus to "reject" TOP-001-2 based on a number of issues, primarily the Reliability Directive issue and the definition associated with it. There is a lot of concern with the term "Adverse Reliability Impact" which appears in that term which is also being updated and currently filed with FERC. In addition there is another drafting team working on COM-002 which is also reviewing the Reliability Directive issue. Many on the RSC believe NERC is properly coordinating these efforts and that the uncertainty of the outcome of the "in process filing related to the new Adverse Reliability Impact is concerning enough to cast a NO vote to **Reject** this TOP-001-2 standard.

In addition, the TOP-002 and 003 standards have received some concerns regarding certain aspects of an RC's data requirements. These data requirements, as outlined in the standard are viewed by some to potentially restrict the RC from requesting the data it may need so the ISO's may be casting a negative vote to reject the standard on these as well. No other RSC members expressed concerns other than those articulated here. NPCC and other members of RSC do not see a fatal flaw or "showstopper" in these two.

Please contact me if you have any questions.

Thanks,

Guy V. Zito
Asst. Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2007-03 Real-time Operations | Three Ballot Windows and Three Non-binding Poll Windows Now Open
Date: Tuesday, January 03, 2012 11:26:55 AM

Standards Announcement

Project 2007-03 Real-time Operations

Three Ballot Windows and Three Non-binding Poll Windows Now Open Through 8 p.m. Eastern on Thursday, January 12, 2012

Now Available

Three successive ballots of the following standards, and three non-binding polls of the associated VRFs and VSLs, are open through 8 p.m. Eastern on Thursday, January 12, 2012:

- TOP-001-2 Coordination of Transmission Operations
- TOP-002-3 Operations Planning
- TOP-003-2 Operational Reliability Data

Clean and redline versions of these standards and the associated implementation plan and VRFs and VSLs, are posted on the project webpage. Note that TOP-001-2, TOP-002-3, and TOP-3-2 reflect the merging of the following standards into the three proposed TOP standards, making it impractical to post a "redline" of the three proposed standards that shows the changes to the last approved versions of these standards. The last approved versions of the standards listed below have been posted on the project's web page for easy reference, and a mapping document has been posted so stakeholders can see whether the drafting team proposed retiring, revising or moving each requirement in the following standards into one of the proposed TOP standards.

- PER-001-0 Operating Personnel Responsibility and Authority
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2a Normal Operations Planning
- TOP-003-1 Planned Outage Coordination
- TOP-004-2 Transmission Operations
- TOP-005-2 Operational Reliability Information
- TOP-006-2 Monitoring System Conditions
- TOP-007-0 Reporting SOL and IROL Violations
- TOP-008-1 Response to Transmission Violations

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standards and opinions for the non-binding polls from the following page: https://standards.nerc.net/CurrentBallots.aspx

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Thursday, January 12, 2012**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line,

unofficial copy of the comment form is posted on the project page.

Special Instructions for Submitting Comments with a Ballot or Non-binding Poll
Please note that comments submitted during the formal comment period, the ballots for the standards, and the non-binding polls of VRFs and VSLs all use the same electronic form, and will be compiled into a single report with duplicate comments submitted by the same entity removed and duplicate comments submitted by multiple entities consolidated. **Therefore, it is NOT necessary for ballot pool members to submit more than one set of comments. The drafting team requests that all stakeholders (ballot pool members as well as other stakeholders) submit all comments through the electronic comment form.**

Next Steps
The drafting team will consider all comments submitted during this formal comment and ballot period to determine whether to make additional revisions to the standards.

Background
The Project 2007-03 drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. The team has also made revisions to address outstanding Order 693 directives. Additional information is available on the project page.

Standards Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2008-10 Interpretation of CIP-006-x for Progress Energy

Recirculation Ballot Results

Now Available

A recirculation ballot of an interpretation of CIP-006-x Requirement R6 concluded on December 19, 2011. The interpretation was approved by the ballot pool. Voting statistics are listed below, and the Ballot Results webpage provides a link to the detailed initial ballot results.

Recirculation Ballot Results
Quorum: 88.02%
Approval: 96.04%

Next Steps
The interpretation will be presented to the NERC Board of Trustees for action, and if adopted, filed with regulatory authorities.

Background
On April 2, 2008, clarification was requested by Progress Energy on CIP-006-1, specifically on whether Electronic Security Perimeter wiring external to a Physical Security Perimeter must be protected within a six-wall boundary.

Initial ballots ended on August 16, 2008, and October 12, 2009. In November 2009, the NERC Board of Trustees issued guidance concerning interpretations, and development of more formal process for addressing interpretations consistent with BOT guidance, as well as the overall workload d priorities of the Project 2008-06 CIP standards drafting team, resulted in a delay in further processing.

In June 2011, the Standards Committee established and appointed members for a standing CIP Interpretation Drafting Team to process the CIP-related interpretations that remain outstanding, including Project 2008-10. A new project team was formed for this interpretation from the CIP Interpretation Drafting Team. In developing the revised interpretation for this successive ballot, the team considered and discussed FERC Order No. 706 and subsequent versions of the CIP standards. In addition, since the previous versions of this interpretation were posted, the Standards Committee has published Guidelines for Interpretation Drafting Teams that were applied by the CIP Interpretation Drafting team.

Additional information on Project 2008-10 is available on the project webpage. Additional information on the activities of the CIP Interpretation Drafting Team is available on the team's webpage.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2007-03 Two Non-binding Polls Extended Through January 19th
Date: Thursday, January 19, 2012 2:25:51 PM

Standards Announcement

Project 2007-03 Real-time Operations

Two Non-binding Poll Windows Extended Through January 19th at 8 p.m. Eastern

Two of the non-binding polls that were to conclude last night did not reach quorum, TOP-001-2 and TOP-003-2. We will be extending these non-binding polls one day at a time until the quorum is reached.

If you have not already cast an opinion for TOP-001-2 and TOP-003-2, please do so before 8 p.m. tonight.

Now Available

Thank you.

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From:	Guy V. Zito
To:	rsballot
Cc:	rsc
Subject:	NPCC Ballot Recommendation and Issues, Project 2007-03 — Real-time Transmission Operations — TOP-001-2, TOP-002-3 and TOP-003-2
Date:	Monday, January 09, 2012 8:01:42 AM
Importance:	High

NPCC Members of the NERC Registered Ballot Body,

The Regional Standards Committee (RSC) has reviewed the subject project currently posted for ballot through 8 pm January 12, 2012. The project involves revision to three standards as indicated above. The RSC has reached a consensus to "reject" TOP-001-2 based on a number of issues, primarily the Reliability Directive issue and the definition associated with it. There is a lot of concern with the term "Adverse Reliability Impact" which appears in that term which is also being updated and currently filed with FERC. In addition there is another drafting team working on COM-002 which is also reviewing the Reliability Directive issue. Many on the RSC believe NERC is properly coordinating these efforts and that the uncertainty of the outcome of the "in process filing related to the new Adverse Reliability Impact is concerning enough to cast a NO vote to **Reject** this TOP-001-2 standard.

In addition, the TOP-002 and 003 standards have received some concerns regarding certain aspects of an RC's data requirements. These data requirements, as outlined in the standard are viewed by some to potentially restrict the RC from requesting the data it may need so the ISO's may be casting a negative vote to reject the standard on these as well. No other RSC members expressed concerns other than those articulated here. NPCC and other members of RSC do not see a fatal flaw or "showstopper" in these two.

Please contact me if you have any questions.

Thanks,

Guy V. Zito
Asst. Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: Guy V. Zito
To: rsballot
Cc: rsc
Subject: FW: NERC Ballot - Reliablity Coordination
Date: Tuesday, February 07, 2012 8:20:10 AM
Importance: High

Correction to the below is the third standard is IRO-001 and an Affirmative.

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: Guy V. Zito
Sent: Tuesday, February 07, 2012 8:06 AM
To: rsballot
Cc: rsc
Subject: NERC Ballot - Reliablity Coordination

NPCC Members of the NERC Registered Ballot Body,

Project 2006-06 — Reliability Coordination— COM-001, COM-002 and IRO-001-3 is currently open for ballot through 8pm February 8th. The RSC has been deliberating the recommendation of a voting position and has been unable to reach consensus regarding the reasons for the voting positions as well as the positions themselves. Members have expressed concerns that the standards are not "results based format" nor are they written to the objectives of the results based project. Detailed comments may be found on the NPCC website.

https://www.npcc.org/Standards/Regional%20Standards%20Comments/Forms/Public%20List.aspx

NPCC's voting postion as the Regional Entity for this successive ballot are as follows;

COM-001- Negative (Primary concern here is with the phrase "within the same interconnection" which appears in R1.2 and R2.2. This removes any standard requirement for adjacent RCs that may not be in the same interconnection from communicating with each other. Some believe that this constitutes a "gap" in reliablity and is a concern.
COM-002- Affirmative
COM-002- Affirmative

If you have any questions please contact me.

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: Guy V. Zito
To: rsc
Subject: FW: IESO Comments and Tentative Voting Positions on COM-001 and IRO-001
Date: Thursday, February 02, 2012 4:15:09 PM

RSC Members,

I am having a discussion with Ben Li about this. This is a reliability issue and my suggestion will be for the SDT to address the concern in a Regional Variance for ERCOT, who apparently has initiated the revision causing the issue. Based on Ben's remarks below I believe we have a showstopper for this project and am prepared to recommend a Negative vote not to accept the standard with reasons below. Please provide me with your viewpoints and if we can achieve a consensus to reject this standard as its been revised.

Lee, have you incorporated the below into our draft comments for consideration by the group?

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: Ben Li Associates [ben@benli.ca]
Sent: Thursday, January 26, 2012 4:02 PM
To: rsc
Subject: IESO Comments and Tentative Voting Positions on COM-001 and IRO-001

RSC:

The IESO has the following concerns with the posted COM-001-2 and IRO-001-3 under Project 2006-06 — Reliability Coordination. The IESO is contemplating a NO vote for these two standards.

COM-001

1. R1.2 and R2.2: The phrase “within the same Interconnection” is improper; it needs to be removed. RCs between two Interconnections still need to communicate with each other for reliability coordination (e.g. between Quebec and the other RCs in the NPCC region to coordinate reliability issues including curtailing interchange transactions crossing Interconnection boundary). The SDT’s response to industry comments on the previous posting that the phrase was added to address the ERCOT situation (that ERCOT does not need to communicate with other RCs and that such coordination takes place between TOPs) leaves a reliability gap.
2. R3.5 and R4.3: The phrase “synchronously connected within the same Interconnection” is also improper; it needs to be removed. TOPs do communicate with other TOPs including those asynchronously connected and in another Interconnection (e.g.

between Quebec and all of its asynchronously interconnected neighbors). The reason that was used in response to the above comments (coordination among TOPs for DC tie operation) contradicts with the inclusion of this phrase in R3.5 and R4.3.

3. R4 and R6: not requiring an Alternative Interpersonal Communication capability between the BAs and the DP and GOP can result in a reliability gap. If Interpersonal Communication capability between the BAs and these entities is required to begin with to enable BAs to communicate with these entities (such as operating instructions or Reliability Directives) to ensure reliable operations, then an alternative capability is also needed to ensure this objective is achieved when the primary capability fails.

4. Measure M3 does not cover the added R3.5 condition (having Interpersonal Communications capability with each adjacent TOP). M3 needs to be revised.

IRO-001

The IESO is unable to support this standard as written since Data Retention Section does not reflect the revised requirements. For examples: the Electric Reliability Organization is no longer a responsible entity; the Reliability Coordinator should replace the ERO for keeping data for R1; Transmission Operator, Balancing Authority, Generator Operator and Distribution Provider should replace the Reliability Coordinator for keeping data for R2; and there is no R4/M4.

Please consider our views for inclusion in the NPCC comments and in assessing your voting position.

Thanks

Ben

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2006-06 | Three Ballot Windows and Three Non-binding Poll Windows - Temporarily Suspended
Date: Tuesday, January 31, 2012 10:01:42 AM

Standards Announcement

Project 2006-06 Reliability Coordination

Three Ballot Windows and Three Non-binding Poll Windows – Temporarily Suspended

We have temporarily suspended balloting while we work to resolve a technical issue, and will notify balloters when balloting can resume.

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

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

You have received this email because you are a registered representative in the Registered Ballot Body.

From: Lee R. Pedowicz
To: rscmembers; "timothy_cooper@fpl.com"; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject: FW: NERC: Standards Announcement - Project 2006-06 | Three Ballot Windows and Three Non-binding Poll Windows Now Open | January 30 - February 8, 2012
Date: Monday, January 30, 2012 11:16:18 AM

Good morning.

For information.

Lee

From: Monica Benson [mailto:Monica.Benson@nerc.net]
Sent: Monday, January 30, 2012 9:37 AM
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2006-06 | Three Ballot Windows and Three Non-binding Poll Windows Now Open | January 30 - February 8, 2012

Standards Announcement

Project 2006-06 Reliability Coordination

Three Ballot Windows and Three Non-binding Poll Windows Now Open
January 30 - February 8, 2012

Now Available

Ballot windows are open through **8 p.m. Eastern on Wednesday, February 8, 2012** for three successive ballots (one for each of the following standards and the associated implementation plans) and three non-binding polls of the VRFs and VSLs associated with each standard:

- COM-001-2 – Communications
- COM-002-3 – Communication and Coordination
- IRO-001-3 – Reliability Coordination – Responsibilities and Authorities

Clean and redline versions of each standard and the associated implementation plan and VRFs and VSLs are posted on the project webpage. In addition, the following supporting materials have been posted on the project page:

- Mapping Document for each standard - Identifies each requirement in the approved version of the standard and how the requirement has been treated in the current draft.
- VRF and VSL Justification – Identifies how the proposed VRFs and VSLs for each standard meet NERC and FERC guidelines.
- Last approved versions of COM-001 and COM-002 – Because the changes from the last approved versions of these two standards are so extensive, a redline showing changes against that last approved version is not useful. The last approved versions are posted as a convenience to stakeholders.

Instructions for Balloting
Members of the ballot pools associated with this project may log in and submit their votes for

the standards and opinions for the non-binding polls from the following page: https://standards.nerc.net/CurrentBallots.aspx.

Instructions for Commenting
A formal comment period is open through **8 p.m. Eastern on Wednesday, February 8, 2012**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Special Instructions for Submitting Comments With a Ballot or Non-binding Poll
Please note that comments submitted during the formal comment period, the ballots for the standards, and the non-binding polls of VRFs and VSLs all use the same electronic form, and will be compiled into a single report with duplicate comments submitted by the same entity removed and duplicate comments submitted by multiple entities consolidated. **Therefore, it is NOT necessary for ballot pool members to submit more than one set of comments. The drafting team requests that all stakeholders (ballot pool members as well as other stakeholders) submit all comments through the electronic comment form.**

Next Steps
The drafting team will consider all comments submitted to determine whether to make additional revisions to the standards.

Background
The Reliability Coordination Standards Drafting Team was tasked with 1) ensuring that the reliability-related requirements applicable to the Reliability Coordinator are clear, measurable, unique, and enforceable; 2) ensuring that this set of requirements is sufficient to maintain reliability of the Bulk Electric System; and 3) revising the group of standards based on FERC Order 693.

During the course of this project, the Reliability Coordination Standards Drafting Team incorporated changes due to the work of the IROL Standards Drafting Team. Two standards from the original Standards Authorization Request (PER-004 and PRC-001) were moved to other projects due to scope overlap. In addition, the scope of Project 2006-06 was expanded to incorporate directives from FERC Order 693 associated with standard IRO-003-2.

The following three standards that are part of this project were approved by the ballot pool and were adopted by the NERC Board of Trustees in August 2012: IRO-002-3 Reliability Coordination – Analysis Tools; IRO-005-4 - Reliability Coordination-Current Day Operations; and IRO-014-2 – Coordination Among Reliability Coordinators. Additional information is available on the project webpage.

Standards Development Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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You are currently subscribed to standards as: lpedowicz@npcc.org
To unsubscribe send a blank email to leave-1281702-171282.3516124aa26cd8bdadcf80768b524b3d@listserv.nerc.com

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2010-07 Generator Requirements at the Transmission Interface | Non-binding Poll January 4-13, 2012
Date: Wednesday, January 04, 2012 11:17:30 AM

Standards Announcement

Project 2010-07
Generator Requirements at the Transmission Interface

Non-Binding Poll – January 4-13, 2012

Now Available

Over the last year, the Project 2010-07 Generator Requirements at the Transmission Interface SDT has proposed and vetted changes to FAC-001-1, FAC-003-X, FAC-003-3, and PRC-004-2.1. All four standards were approved by their respective ballot pools in recirculation ballots that ended on December 23, 2011. FAC-001, FAC-003-3, and PRC-004-2.1a (which includes the interpretation from PRC-004-2a) will be presented to the NERC Board of Trustees for approval in February 2012.

From January 4-13, 2012, the SDT will be conducting a non-binding poll of the VSLs and VRFs that were substantively revised. FAC-003-X's and PRC-004-2.1a's VSLs and VRFs were not revised at all and FAC-003-3's VSLs and VRFs were only edited to change the responsible entity in the VSLs, so only FAC-001-1's VSLs and VRFs are being posted for the non-binding poll.

Detail on Updates to VSLs and VRFs for FAC-001-1, FAC-003-X, FAC-003-3, and PRC-004-2.1a
Because it was a Version 0 standard, FAC-001-0 did not initially have VSLs or VRFs assigned to it. The VSLs for FAC-001-1 were transferred from the VSLs filed by NERC staff on March 21, 2011 (in Supplemental Information to the NERC Compliance Filing in Response to the Order on Violation Severity Levels Proposed by the ERO). The VRFs for FAC-001-1 were transferred into the standard from NERC's VRF Matrix – which includes VRFs that have already been approved by FERC – to bring the format of the standard up to date. For existing Requirements R1 and R4 (applicable to Transmission Owners only), no substantive changes to VSLs or VRFs were made, although typographical errors in the VSLs for R1 was corrected. For new requirement R2 (applicable to Generator Owners only), the Project 2010-07 standard drafting team applied the comparable VRF from R1 and developed a set of VSLs according to NERC and FERC guidelines. For modified Requirement R3 (applicable to Transmission Owners and Generator Owners), no substantive changes to the VSLs or VRFs were made, although a typographical error in the VSLs for R3 was corrected and "Transmission Owner" was changed to "responsible entity."

The proposed changes in FAC-003-3 serve only to make the standard applicable to qualifying Generator Owners, so no changes were proposed for the VRFs for FAC-003-3. The only

modification proposed for the VSLs for FAC-003-3 was to change all references to "Transmission Owner" to "responsible entity."
The proposed change in PRC-004-2.1a Requirement R2 is a clarifying (errata) change that makes clear that generator interconnection Facilities are also part of Generator Owners' responsibility in the context of this standard. Thus, no changes were proposed for the VRFs or VSLs for PRC-004-2.1a.

Instructions for Casting an Opinion in the Non-binding Poll
Members of the ballot pool associated with this project may log in and submit their opinion for the non-binding polls from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps
FAC-001, FAC-003-3, and PRC-004-2.1a will be presented to the NERC Board of Trustees for adoption in February 2012, and information on the non-binding poll results will be provided to the Board for consideration in their decision.

Background
The purpose of Project 2010-07 is to ensure that all generator-owned Facilities are appropriately covered under NERC's Reliability Standards. While many Generator Owners and Generator Operators operate Facilities, commonly known as generator interconnection Facilities, that are considered by some entities to be transmission, these are most often sole-use Facilities that are not part of the integrated grid. As such, they should not be subject to the same standards applicable to Transmission Owners and Transmission Operators who own and operate Transmission Elements and Facilities that are part of the integrated grid.

As part of the BES, generators do affect the overall reliability of the BES. But registering a Generator Owner or Generator Operator as a Transmission Owner or Transmission Operator, as has been the solution in some cases in the past, may decrease reliability by diverting the Generator Owner's or Generator Operator's resources from the operation of the equipment that actually produces electricity – the generation equipment itself.

The SDT's goal is to ensure that an adequate level of reliability is maintained in the BES by clearly describing which standards need to be applied to generator interconnection Facilities that are not already applicable to Generator Owners or Generator Operators. This can be accomplished by properly applying FAC-001, FAC-003, PRC-004, and later, PRC-005, to Generator Owners. Additional information is available on the project page.
Standards Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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

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You have received this email because you are a registered representative in the Registered Ballot Body.

Unofficial Comment Form

Request for Comments Regarding the Draft of CIP Cyber Security Standards Version 5

Please **DO NOT** use this form to submit comments. Please use the electronic comment form to submit comments on the first formal posting of Project 2008-06 – CSO706 Version 5 CIP Standards. The electronic comment form must be completed by **January 6, 2012.**

2008-06 Project Page

If you have questions please contact Steven Noess at steven.noess@nerc.net or 404-446-9691.

Background

In 2008, FERC Order No. 706 directed the ERO to develop modifications to Version 1 of the NERC CIP Cyber Security Standards to address a range of concerns in various areas of the Version 1 standards.

A Standards Drafting Team (SDT) was appointed by the NERC Standards Committee on August 7, 2008 to develop these modifications as part of Project 2008-06 – Cyber Security Order 706. The SDT has been charged to review each of the CIP reliability standards and address the modifications identified in the FERC Order No. 706. The SDT began meeting in October 2008.

Prior to this posting, the SDT developed CIP-002-2 through CIP-009-2 to comply with the near-term specific directives of FERC Order No. 706. This version of the Standards was approved by FERC in September of 2009 with additional directives to be addressed within 90 days of the order. In response, the SDT developed CIP-003-3 through CIP-009-3, which FERC approved in March 2010.

Throughout this period, the SDT has continued efforts to develop an approach to address the remaining FERC Order No. 706 directives. An original draft version of CIP-010 and CIP-011, which included the categorization of cyber systems in CIP-010 and associated cyber security requirements consolidated into a single CIP-011, were posted for informal comment in May of 2010. After reviewing and analyzing responses from the industry, the SDT determined it was infeasible to address all of the concerns and achieve industry consensus on CIP-010 and CIP-011 by the planned target date of December 2010. Consequently, the SDT developed a limited scope of requirements in Version 4 of the CIP Cyber Security Standards (CIP-002-4 through CIP-009-4) as an interim step to address the more immediate concerns raised in FERC Order No. 706, paragraph 236, especially those associated with CIP-002's identification of Critical Assets and the risk-based methodology used for the identification. CIP-002-4, which included a bright-line based approach for criteria used to identify Critical Assets in lieu of an entity defined risk-based methodology, and the conforming changes to CIP-003 through CIP-009, was approved by the Board of Trustees in January of 2011. On September 15, 2011, FERC issued a Notice of Proposed Rulemaking (RM11-11) to approve Version 4 of the Cyber Security Standards with a 60 day comment period.

This draft Version 5 of the NERC CIP Cyber Security Standards is intended to address the remaining standards-related issues of FERC Order No. 706.

The SDT believes the NERC Version 5 CIP Cyber Security Standards provide a cyber security framework for the categorization and protection of BES Cyber Systems to support the reliable operation of the Bulk Electric System. These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the cyber systems needed to support Bulk Electric System reliability, and the risks to which they are exposed.

- Standard CIP-002-5 requires the categorization of these BES Cyber Systems according to bright-line criteria that characterize their impact on the BES Reliability Operating Services they support to ensure the reliable operation of the Bulk Electric System. These BES Reliability Operating Services are based on the Reliability Functions provided by these applicable Responsible Entities' Functional Registration. The "bright-line" criteria contained in Attachment 1 – Impact Categorization of BES Cyber Assets and BES Cyber Systems of the draft CIP-002-5 standard provide the basis of the categorization.
- CIP-003-5 through CIP-009-5, CIP-010-1, and CIP-011-1 in the Version 5 CIP Cyber Security Standards define the cyber security requirements to be applied to the BES Cyber Systems according to the categorization performed in CIP-002-5.
- CIP-003 through CIP-009 generally follow the organization of Versions 1 through 4 of CIP-003 through CIP-009.
- CIP-010-1 is a new standard that contains the Configuration Management and Vulnerability Assessment requirements previously defined across several CIP standards in Versions 1 through 4.
- CIP-011-1 is a new standard that defines Information Protection and Media Sanitization requirements previously defined across many standards in Versions 1 through 4.

The Implementation Plan for Version 5 CIP Cyber Security Standards describes the proposed effective dates for Version 5 CIP Cyber Security Standards.

The Team is seeking industry feedback and suggestions on this Version 5 of the CIP Cyber Security Standards and its Implementation Plan. The industry feedback will be considered by the SDT in revising and refining Version 5 and related documents.

The SDT is providing this form for industry participants to offer their comments on this posted draft of Version 5 of the CIP Cyber Security Standards.

For each question, please indicate whether or not you agree with the modification being proposed. If you disagree with the proposed modification, please explain why you disagree and provide as much detail as possible regarding your disagreement including any suggestions for altering the proposed

modification that would eliminate or minimize your disagreement. The SDT would appreciate responses to as many of these questions as you are willing to supply.

You do not have to answer all questions. Enter all comments in Simple Text Format.

Questions

1. Many definitions in the Definitions document contain modified definitions from existing terms and new definitions for terms used in these standards. Do you have any suggestions that would improve the proposed definitions? If so, please explain and provide specific suggestions for improvement.

   ☒ Yes

   ☐ No

   Comments: Refer to additional comments submitted for Question 49.

   "Suspicious" is not an auditable term, and should be removed. What is an "attempt"? What attempts are serious enough to justify having to be reported? The definition should be made to read:

   BES Cyber Security Incident

   A malicious act that:

   - Compromises the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or,
   - Disrupts the operation of a Critical Cyber Asset BES Cyber System, or
   - Results in unauthorized physical access into a Defined Physical Boundary.

   Under "BES Reliability Operating Services":

   - "Identify and monitor flow gates" under "Managing Constraints" appears to be missing its bullet
   - Recommend that "Change management" under "Situational Awareness" be clarified to changes in the BES instead of IT change management
   - Recommend clarification that "Facility" is the NERC Glossary term--in "facility operational data and status" under "Inter-Entity Real-Time Coordination and "Communication":
     - Request clarification of the scope of this "Operational Directives". Does it include a company's messaging system? Two-way radios? What is the relationship with the new COM-002?
     - Request clarification that these Coordination and Communications are limited to Reliability, not Market Systems.

- Recommend that each BES Reliability Operating Services have a beginning paragraph that clearly associates that service to the BES like the "Dynamic Response to BES Conditions"
- For clarity, recommend stating which Functions are associated with each BES Reliability Operating Services instead of forcing everyone to interpret.

2. CIP-002-5 Attachment 1 contains criteria that provide the basis for the categorization of BES Cyber Systems and BES Cyber Assets. Most of these criteria are similar to those already approved by the industry as part of Version 4. Do you have any suggestions that would improve the proposed criteria? If so, please explain and provide specific suggestions for improvement.

   ☒ Yes

   ☐ No

   Comments: Recommend that 2.8, 2.9 and 2.11 start with “Applies to all Regions except…” For 2.8, 2.9 and 2.11 request that the SDT clarify whether the exception is all, or not WECC.

   In 2.12, “system” and “Facility” are not the proper terms to use. An operator is responsible for automatic load shedding or the other forms of load relief mentioned.

   For 2.3, 2.8, and 2.9, need to clarify the role and responsibility of PC, TP, GO, GOp, RC and the PA on impact ratings. Who is responsible for assets being improperly categorized? What avenues are there for appeal?

3. Requirement R1 of draft CIP-002-5 states, “Each Responsible Entity that owns BES Cyber Assets and BES Cyber Systems shall identify and categorize its High and Medium Impact BES Cyber Assets and BES Cyber Systems according to the criteria contained in *CIP-002-5 Attachment I – Impact Categorization of BES Cyber Assets and BES Cyber Systems.* All other BES Cyber Assets and BES Cyber Systems that it owns shall be deemed to be Low Impact and do not require discrete identification.” Further, part 1.1 of R1 states “Update the identification and categorization within 30 calendar days of a change to BES Elements and Facilities is placed into operation, that is intended to be in service for more than 6 calendar months and that causes a change in the identification or categorization of the BES Cyber Assets or BES Cyber Systems from a lower to a higher impact category.” Do you agree with the proposed Requirement R1? If not, please explain why and provide specific suggestions for improvement.

   ☐ Yes

   ☒ No

Comments: For clarity, request changing R1.1 from “Update the identification and categorization within 30 calendar days of a change to BES Elements and Facilities is placed into operation” to “Update the identification and categorization within 30 calendar days when a change to BES Elements and Facilities is placed into operation”.

For clarity and consistency with the previous change, request changing M1 from “as required in R1 and list of changes to the BES (” to “as required in R1 and list of changes to the BES Elements and Facilities)”.

The word “intended” should not be used in the requirement because it is not auditable.

Regarding CIP-002-5, the Applicability sections of CIP-002-5 through CIP-011-5 should be consistent. Note that CIP-005-5 and CIP-006-5 sections 4.2.2 are different from the other Standards.

The capitalized term “Facilities” in Section 4 needs to be clarified. Does this refer to the NERC Glossary of Terms or section 4.2? For example, see CIP-002-5 sections 4.1.2 and 4.2.1. This question applies to the Applicability sections of CIP-002-5 – CIP-011-5.

There are potential issues with implementation of CIP Version 4 versus CIP Version 5. As written, CIP Version 5 appears to have some requirements that would be enforceable on the effective date and there may be a need for an implementation and/or conversion timeframe. The words in the Standards Requirements appear to be at odds with the Implementation Plan and clarity is needed. Additionally, there is concern with the need to be “compliant” with requirements that simply rely on documentation. Documentation is not a mechanism to ensure reliability and/or security of the bulk power system. An approach that should be considered is to have documentation “requirements” in a guidance document rather than in the requirements in the standard.

The process to classify and categorize cyber assets (CIP-002) and then identify other assets which must be protected (CIP-005 and CIP-007) is excessively complicated. In addition to the BES Cyber Assets that are classified as high, medium, and low in CIP-002, the other standards introduce 10 additional categories of assets to protect in various ways:

- Associated Physical Access Control Systems
- Associated Protected Cyber Assets
- Associated Electronic Access Control or Monitoring Systems
- Electronic Access Points (with External Routable Connectivity)
- Electronic Access Points (with dial-up connectivity)
- Locally Mounted Hardware or Devices Associated with Defined Physical Boundaries
- Transient Cyber Assets

- Medium Impact BES Cyber Systems with External Routable Connectivity
- Medium Impact BES Cyber Systems at Control Centers
- Low Impact BES Cyber Systems with External Routable Connectivity

Some of these assets are defined in the Applicability Section of the standard (which will not be included in the final standard) while some are introduced in the standards themselves and these categories may or may not be included in the definitions document. This approach is overly complicated and does not allow the CIP Standards to stand alone without dependence on other documents. This also leads to the need for future questions, interpretations, CANs, etc. The Standards should be revised so that all assets which need to be protected are defined in CIP-002 rather than introduced throughout the Standards.

4. Requirement R2 of draft CIP-002-5 states, "The Responsible Entity shall have its CIP Senior Manager or delegate approve the identification and categorization required by R1 initially upon the effective date of the standard and at least once each calendar year thereafter, not to exceed 15 calendar months between approvals, even if it has no identified High or Medium BES Cyber Assets or BES Cyber Systems." Do you agree with the proposed Requirement R2? If not, please explain why and provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

5. Do you agree with the proposed Violation Risk Factors and Violation Severity Levels for CIP-002-5? If not, please provide suggested improvements on the proposed VRFs and VSLs.

   ☐ Yes

   ☐ No

   Comments:

6. CIP-003-5 R1 states "Each Responsible Entity shall identify, by name, a CIP Senior Manager." Do you agree with the proposed Requirement R1? If not, please explain why and provide specific suggestions for improvement.

   ☐ Yes

☒ No

Comments: Regarding CIP-003-5, the Applicability sections of CIP-002-5 through CIP-011-5 should be consistent. Note that CIP-005-5 and CIP-006-5 sections 4.2.2 are different from the other Standards.

The capitalized term "Facilities" in Section 4 needs to be clarified. Does this refer to the NERC Glossary of Terms or section 4.2? For example, see CIP-002-5 sections 4.1.2 and 4.2.1. This question applies to the Applicability sections of CIP-002-5 – CIP-011-5.

There are potential issues with implementation of CIP Version 4 versus CIP Version 5. As written, CIP Version 5 appears to have some requirements that would be enforceable on the effective date and there may be a need for an implementation and/or conversion timeframe. The words in the Standards Requirements appear to be at odds with the Implementation Plan and clarity is needed. Additionally, there is concern with the need to be "compliant" with requirements that simply rely on documentation. Documentation is not a mechanism to ensure reliability and/or security of the bulk power system. An approach that should be considered is to have documentation "requirements" in a guidance document rather than in the requirements in the standard.

7. CIP-003-5 R2 states "Each Responsible Entity shall implement one or more documented cyber security policies that represents the Responsible Entity's commitment to the protection of its BES Cyber Systems and addresses the following topics:" and then defines the areas that must be addressed in the policies. Do you agree with the proposed Requirement R2? If not, please explain why and provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

8. CIP-003-5 R3 states "Each Responsible Entity shall review each of its cyber security policies and obtain the approval of its CIP Senior Manager, initially upon the effective date of the standard and at least once each calendar year thereafter, not to exceed 15 calendar months between reviews and between approvals." Do you agree with the proposed Requirement R3? If not, please explain why and provide specific suggestions for improvement.

   ☐ Yes

☐ No

Comments:

9. CIP-003-5 R4 states "Each Responsible Entity shall make individuals who have access to BES Cyber Systems aware of elements of its cyber security policies appropriate for their job function." Do you agree with the proposed Requirement R4? If not, please explain why and provide specific suggestions for improvement.

   ☐ Yes

   ☒ No

   Comments: The last bullet for M4 on page 12 is inconsistent with R4 since M4 requires periodic training instead of R4's making staff aware of cyber security policies. Request that M4 be updated to be consistent with R4.

10. CIP-003-5 R5 states "The CIP Senior Manager shall be responsible for all approvals and authorizations required in the CIP standards. The CIP Senior Manager may delegate the authority for any approvals and authorizations required in the CIP standards with the exception of the approval of the Cyber Security Policy required in CIP-003-5 R3. The authority for subsequent delegations may also be delegated. These delegations shall be documented (by position or name of the delegate), dated, and approved and shall specify the authority that is being delegated." Do you agree with the proposed Requirement R5? If not, please explain why and provide specific suggestions for improvement.

    ☒ Yes

    ☐ No

    Comments:

11. CIP-003-5 R6 states "Changes to the CIP Senior Manager and any delegations shall be documented within thirty calendar days of the change." Do you agree with the proposed Requirement R2? If not, please explain why and provide specific suggestions for improvement.

    ☐ Yes

    ☒ No

    Comments: The requirement has a typographical error. Footnote 2 is not in superscript.

    Request clarification that R6 does not require re-delegation when the CIP Senior Manager changes.

    Request change from "Changes to the CIP Senior Manager and" to "Changes to the CIP Senior Manager or".

12. Do you agree with the proposed Violation Risk Factors and Violation Severity Levels for CIP-003-5? If not, please provide suggested improvements on the proposed VRFs and VSLs.

    ☐ Yes

    ☐ No

    Comments:

13. CIP-004-5 R1 states "Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable items in *CIP-004-5 Table R1 – Security Awareness Program*." The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R1 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

    ☐ Yes

    ☒ No

    Comments: Regarding CIP-004-5, the Applicability sections of CIP-002-5 through CIP-011-5 should be consistent. Note that CIP-005-5 and CIP-006-5 sections 4.2.2 are different from the other Standards.

    The capitalized term "Facilities" in Section 4 needs to be clarified. Does this refer to the NERC Glossary of Terms or section 4.2? For example, see CIP-002-5 sections 4.1.2 and 4.2.1. This question applies to the Applicability sections of CIP-002-5 – CIP-011-5.

    There are potential issues with implementation of CIP Version 4 versus CIP Version 5. As written, CIP Version 5 appears to have some requirements that would be enforceable on the effective date and there may be a need for an implementation and/or conversion timeframe. The words in the Standards Requirements appear to be at odds with the Implementation Plan and clarity is needed. Additionally, there is concern with the need to be "compliant" with requirements that simply rely on documentation. Documentation is not a mechanism to ensure reliability and/or security of the bulk power system. An approach that should be considered is to have documentation "requirements" in a guidance document rather than in the requirements in the standard.

14. CIP-004-5 R2 states "Each Responsible Entity shall have a role-based cyber security training program for personnel who need authorized electronic access or authorized unescorted physical access to BES Cyber Systems that includes each of the applicable items in *CIP-004-5 Table R2 – Cyber Security Training Program*." The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R2 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

    ☐ Yes

    ☒ No

    Comments: Request clarification of whether personnel with access to only protected information need training/awareness. SDT should include this as an additional requirement.

    Recommend removal of R2.3 and R2.4 since they are redundant to R2.2, or explain the difference between R2.2 and R2.3, R2.4.

    Request removing "potential" from R2.7 since training should include how to determine whether a BES System Event occurred or not.

15. CIP-004-5 R3 states "Each Responsible Entity shall implement its documented cyber security training program for each individual needing authorized electronic or unescorted physical access that includes each of the applicable items in *CIP-004-5 Table R3 - Cyber Security Training."* The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R3 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

    ☒ Yes

    ☐ No

    Comments:

16. CIP-004-5 R4 states "Each Responsible Entity shall have one or more documented personnel risk assessment programs for individuals needing authorized electronic or unescorted physical access that collectively includes each of the applicable items in *CIP-004-5 Table R4 – Personnel Risk Assessment Program*." The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R4 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

    ☐ Yes

    ☒ No

Comments: For all R4 table entries, recommend changing "documented risk assessment program" to "documented personnel risk assessment program" to avoid confusion with a corporate risk assessment program.

For R4.2 recommend adding language to "grandfather" previous seven-year criminal checks executed for the previous version of CIP Standards. The additional language should spell out when this "grandfathering" expires, which is also when a new check will be required.

17. CIP-004-5 R5 states "Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable elements in *CIP-004-5 Table R5 – Personnel Risk Assessment."* The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R5 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: For clarity, recommend changing 5.1 from "authorized electronic or unescorted physical" to "authorized electronic or authorized unescorted physical".

18. CIP-004-5 R6 states "Each Responsible Entity shall implement one or more documented access management programs that collectively include each of the applicable elements in *CIP-004-5 Table R6 – Access Management Program."* The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R6 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: For R6.1
1. The Responsible Entity should be able to determine the approval process for authorization of access to BES Cyber Systems.
2. Change "authorize electronic access, except" to "authorize electronic access to BES Cyber Systems, except"
3. Change "minimum necessary" to "minimum that the responsible entity considers necessary".

For R6.2 similar comments to R6.1, except that this requirement already refers to "BES Cyber Systems."
1. The Responsible Entity should be able to determine the approval process for authorization of access to BES Cyber Systems.
2. Change "minimum necessary" to "minimum that the responsible entity considers necessary".

For R6.3
1. The Responsible Entity should be able to determine the approval process for authorization of access to BES Cyber System Information.
2. Change “minimum necessary” to “minimum that the responsible entity considers necessary”.

For R6.5, Change “minimum necessary” to “minimum that the responsible entity considers necessary”.

For R6.6
1. Change “minimum necessary” to “minimum that the responsible entity considers necessary” in the Requirement.
2. In the measure for 6.6, change “BES Cyber System information” to “BES Cyber System Information” – capitalize the “I” in Information.

19. CIP-004-5 R7 states “Each Responsible Entity shall implement one or more documented access revocation programs that collectively include each of the applicable items in *CIP-004-5 Table R7 – Access Revocation*.” The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R7 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: Request that the footnote for 7.1 be moved into the requirement.

Recommend changing 7.2 to "For an individual, no longer acting in a role requiring unescorted physical access or electronic access to BES Cyber Systems, unescorted physical access and Interactive Remote Access will be removed within the next calendar day."

Recommend removing the "following the resignation or termination" since it is redundant and inconsistent with the sibling Requirements.

Recommend changing 7.4 from "For resignations or terminations," to "For terminations, resignations, reassignments, or transfers,".

20. Do you agree with the proposed Violation Risk Factors and Violation Severity Levels for CIP-004-5? If not, please provide suggested improvements on the proposed VRFs and VSLs.

☐ Yes

☐ No

Comments:

21. CIP-005-5 R1 states “Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable items in *CIP-005-5 Table R1 – Electronic Security Perimeter*.” The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R1 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: Request clarification on the scenario where Low Impact BES Cyber Systems are mixed in the ESP with High/Medium BES Cyber Systems. Is this Low Impact BES Cyber System subject to 1.1 or 1.2?

Request clarification that the 1.3 Electronic Access Points is the 1.2 identified Electronic Access Points or not?

Request clarification that the 1.5 EAP is the 1.2 identified Electronic Access Point or not?

Request clarification on 1.5's "at each EAP". Is that inside or outside or both?

Regarding CIP-005-5, the Applicability sections of CIP-002-5 through CIP-011-5 should be consistent. Note that CIP-005-5 and CIP-006-5 sections 4.2.2 are different from the other Standards.

The capitalized term “Facilities” in Section 4 needs to be clarified. Does this refer to the NERC Glossary of Terms or section 4.2? For example, see CIP-002-5 sections 4.1.2 and 4.2.1. This question applies to the Applicability sections of CIP-002-5 – CIP-011-5.

There are potential issues with implementation of CIP Version 4 versus CIP Version 5. As written, CIP Version 5 appears to have some requirements that would be enforceable on the effective date and there may be a need for an implementation and/or conversion timeframe. The words in the Standards Requirements appear to be at odds with the Implementation Plan and clarity is needed. Additionally, there is concern with the need to be “compliant” with requirements that simply rely on documentation. Documentation is not a mechanism to ensure reliability and/or security of the bulk power system. An approach that should be considered is to have documentation “requirements” in a guidance document rather than in the requirements in the standard.

22. CIP-005-5 R2 states “Each Responsible Entity allowing Interactive Remote Access to BES Cyber Systems shall implement one or more documented processes that collectively include the applicable items, where technically feasible, in *CIP-005-5 Table R2 – Remote Access Management*.” The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R2 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

    ☐ Yes

    ☒ No

    Comments: Recommend changing 2.1 from "Require an Intermediate Device such that the Cyber Asset initiating Interactive Remote Access does not directly access a BES Cyber System or Protected Cyber Asset." to "Do not allow the Cyber Asset initiating Interactive Remote Access direct access to a BES Cyber System or a Protected Cyber Asset." since the existing Requirement is too prescriptive and does not allow new technology.

    Recommend changing M2.3 from "Note that a UserID is not considered an authentication factor" to "Note that a UserID and password are not considered two authenticating factors" since the existing words are incomplete.

23. Do you agree with the proposed Violation Risk Factors and Violation Severity Levels for CIP-005-5? If not, please provide suggested improvements on the proposed VRFs and VSLs.

    ☐ Yes

    ☐ No

    Comments:

24. CIP-006-5 R1 states “Each Responsible Entity shall implement one or more documented physical security plans that include each of the applicable items in *CIP-006-5 Table R1 – Physical Security Plan.”* The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R1 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

    ☐ Yes

    ☒ No

    Comments: Request clarification of 1.1 Applicability since it does not identify which of High/Medium/Low BES Impact these are "Associated" with Request that Measure 1.2 be consistent (not add a Requirement) with Requirement 1.2, specific to "ingress and egress".

Request Requirement 1.2 be updated to allow "escorted physical access."

Request clarification of Requirement 1.3 "Utilize two or more different and complementary physical access controls" is this multi-factor authentication such as key, badge, keypad or bio-metric?

Request that Measure 1.4 be consistent (not add a Requirement) with Requirement 1.2, specific to "ingress and egress"

Request changing Requirement 1.4 from "Issue real-time alerts (to individuals responsible for response) in response to unauthorized physical access through any access point in a Defined Physical Boundary. " to "issue real time alerts for detection of breach through an access point".

For consistency, recommend removing "applicable" from "protecting applicable BES Cyber Systems" in Requirement 1.6.

Regarding CIP-006-5, the Applicability sections of CIP-002-5 through CIP-011-5 should be consistent. Note that CIP-005-5 and CIP-006-5 sections 4.2.2 are different from the other Standards.

The capitalized term “Facilities” in Section 4 needs to be clarified. Does this refer to the NERC Glossary of Terms or section 4.2? For example, see CIP-002-5 sections 4.1.2 and 4.2.1. This question applies to the Applicability sections of CIP-002-5 – CIP-011-5.

There are potential issues with implementation of CIP Version 4 versus CIP Version 5. As written, CIP Version 5 appears to have some requirements that would be enforceable on the effective date and there may be a need for an implementation and/or conversion timeframe. The words in the Standards Requirements appear to be at odds with the Implementation Plan and clarity is needed. Additionally, there is concern with the need to be “compliant” with requirements that simply rely on documentation. Documentation is not a mechanism to ensure reliability and/or security of the bulk power system. An approach that should be considered is to have documentation “requirements” in a guidance document rather than in the requirements in the standard.

25. CIP-006-5 R2 states “Each Responsible Entity shall implement its documented visitor control program that includes each of the applicable items in *CIP-006-5 Table R2 – Visitor Control*

Program." The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R2 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: Recommend removing "continuous" from "Require continuous escorted access of visitors" so that the Requirement is auditable from Requirement 2.1.

Recommend changing 2.2 from "the entry and exit on a per 24-hour basis," to "the entry and exit to the Defined Physical Boundary on a per 24-hour basis, ".

26. CIP-006-5 R3 states "Each Responsible Entity shall implement one or more documented maintenance and testing programs that collectively include each of the applicable items in *CIP-006-5 Table R3 – Maintenance and Testing Program*." The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R3 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: Request clarification on what the "Associated" "Applicability" (High/Medium/Low BES Impact) for 3.1 and 3.2

Request capitalization of "locally mounted hardware or devices" in Requirement 3.1 so that it refers back to the defined term "Locally Mounted Hardware or Devices" .

27. Do you agree with the proposed Violation Risk Factors and Violation Severity Levels for CIP-006-5? If not, please provide suggested improvements on the proposed VRFs and VSLs.

☐ Yes

☐ No

Comments:

28. CIP-007-5 R1 states "Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable items in CIP-007-5 Table R1 – Ports and Services." The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R1 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: Request clarification on 1.1, is this at the BES Cyber System level or at the Asset level or can the Entity choose?

Request clarification on 1.1, why does the Measure refer to BES Cyber Asset while the Applicability refers to Systems?

Regarding CIP-007-5, the Applicability sections of CIP-002-5 through CIP-011-5 should be consistent. Note that CIP-005-5 and CIP-006-5 sections 4.2.2 are different from the other Standards.

The capitalized term "Facilities" in Section 4 needs to be clarified. Does this refer to the NERC Glossary of Terms or section 4.2? For example, see CIP-002-5 sections 4.1.2 and 4.2.1. This question applies to the Applicability sections of CIP-002-5 – CIP-011-5.

There are potential issues with implementation of CIP Version 4 versus CIP Version 5. As written, CIP Version 5 appears to have some requirements that would be enforceable on the effective date and there may be a need for an implementation and/or conversion timeframe. The words in the Standards Requirements appear to be at odds with the Implementation Plan and clarity is needed. Additionally, there is concern with the need to be "compliant" with requirements that simply rely on documentation. Documentation is not a mechanism to ensure reliability and/or security of the bulk power system. An approach that should be considered is to have documentation "requirements" in a guidance document rather than in the requirements in the standard.

29. CIP-007-5 R2 states "Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable items in CIP-007-5 Table R2 – Security Patch Management." The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R2 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: Request clarification of "remediation" in 2.2 since it reads that the patch must be applied, which does not allow to have an exception when applying the patch is the worst scenario such as creating a denial of service.

For 2.2, suggest wording like "create a remediation plan or a plan to mitigate the vulnerability if it is determined that the patch cannot be safely applied".

What is the intent of CIP Exceptional Circumstances in 2.3? Is it intended to mean deviating from the remediation plan in 2.2? Is the "process for remediation" specific to the patch or the overall process?

30. CIP-007-5 R3 states “Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable items in *CIP-007-5 Table R3 – Malicious Code Prevention*.” The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R3 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: Request allowances in 3.3 for signatures/pattern updates that cause trouble.

Recommend changing 3.4 from "Transient Cyber Assets and removable media" to "Transient Cyber Assets or removable media".

The Measure for 3.4 does not match the Requirement.

31. CIP-007-5 R4 states “Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable items in *CIP-007-5 Table R4 – Security Event Monitoring*.” The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R4 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: Request changing 4.1.4 from "Any detected potential malicious activity" to "Any detected malicious activity" since the scope of potential includes all activities.

Request clarification on 4.3, does the failure need to be detected within a calendar day?

Request the rationale of 4.5's "two weeks". Recommend one month as a compromise between the prior version's 90 days and the suggested one week.

In 4.5 clarification is needed for the associated protected cyber assets. Are these protected cyber assets associated with only high impact BES cyber systems, or could they be associated with medium impact BES cyber systems?

32. CIP-007-5 R5 states "Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable items in *CIP-007-5 Table R5 – System Access Controls*." The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R5 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: For 5.2, does the CIP Senior Manager or delegate approval policy or procedure for each authorization of access?

In 5.2, should the Requirement be interpreted as "each use" as in "The CIP Senior Manager or delegate must authorize the use of each administrator, shared, default, or other generic account types."

Request clarification of 5.5.3, specifically "the significance of passwords in the set of controls used to prevent unauthorized access to the BES Cyber System and existing service agreements, warranties or licenses."

33. Do you agree with the proposed Violation Risk Factors and Violation Severity Levels for CIP-007-5? If not, please provide suggested improvements on the proposed VRFs and VSLs.

☐ Yes

☐ No

Comments:

34. CIP-008-5 R1 states "Each Responsible Entity shall have one or more BES Cyber Security Incident response plan(s) that collectively include each of the applicable items in *CIP-008-5 Table R1 – BES Cyber Security Incident Response Plan Specifications*." The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R1 and its parts?

If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: Regarding CIP-008-5, the Applicability sections of CIP-002-5 through CIP-011-5 should be consistent. Note that CIP-005-5 and CIP-006-5 sections 4.2.2 are different from the other Standards.

The capitalized term "Facilities" in Section 4 needs to be clarified. Does this refer to the NERC Glossary of Terms or section 4.2? For example, see CIP-002-5 sections 4.1.2 and 4.2.1. This question applies to the Applicability sections of CIP-002-5 – CIP-011-5.

There are potential issues with implementation of CIP Version 4 versus CIP Version 5. As written, CIP Version 5 appears to have some requirements that would be enforceable on the effective date and there may be a need for an implementation and/or conversion timeframe. The words in the Standards Requirements appear to be at odds with the Implementation Plan and clarity is needed. Additionally, there is concern with the need to be "compliant" with requirements that simply rely on documentation. Documentation is not a mechanism to ensure reliability and/or security of the bulk power system. An approach that should be considered is to have documentation "requirements" in a guidance document rather than in the requirements in the standard.

35. CIP-008-5 R2 states "Each Responsible Entity shall implement its documented BES Cyber Security Incident response plan(s) to collectively include each of the applicable items in *CIP-008-5 Table R2 –BES Cyber Security Incident Response Plan Implementation and Testing."* The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R2 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: 2.1 is a new Requirement. Request the rationale for this new Requirement.

Recommend changing from "When a BES Cyber Security Incident occurs,
the incident response plans must be used when incidents occur and include

recording of deviations taken from the plan during the incident or test." to "When a BES Cyber Security Incident is classified or identified, the Responsible Entity must follow its incident response plan."

Recommend removing “initially upon the effective date of the standard” from 2.2 of Table R2 because it unrealistically forces an Entity to be compliant with two Versions of the Standard at the same time. The increased demands placed upon Entities to be compliant with Version 5 will make it very difficult to become compliant when going from Version 4 to Version 5 within the time frames specified. Grandfathering is not considered.

36. CIP-008-5 R3 states “Conduct sufficient reviews, updates and communications to verify the REs response plan’s effectiveness and consistent application in responding to a Cyber Security Incident(s) impacting a BES Cyber System.” The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R3 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: Recommend removing “initially upon the effective date of the standard” from 3.1 of Table R3 because it unrealistically forces an Entity to be compliant with two Versions of the Standard at the same time. The increased demands placed upon Entities to be compliant with Version 5 will make it very difficult to become compliant when going from Version 4 to Version 5 within the time frames specified. Grandfathering is not considered.

Recommend that 3.2 wording be consistent with the 2.2 wording.

For 3.3, recommend changing 1) "Update" to "Update as necessary" and 2) "the completion of the review of that plan" to "the completion of the review performed in 3.2" .

37. Do you agree with the proposed Violation Risk Factors and Violation Severity Levels for CIP-008-5? If not, please provide suggested improvements on the proposed VRFs and VSLs.

☐ Yes

☐ No

Comments:

38. CIP-009-5 R1 states “Each Responsible Entity shall have one or more documented recovery plans that collectively include each of the applicable items in *CIP-009-5 Table R1 – Recovery Plan Specifications*.” The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R1 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: For 1.3, request clarification of the “protection of information”. Is this integrity, availability or other information protection such as access controls, encryption?

For 1.4, request clarification, is this a backup media verification process? If not what is the intent?

Recommend removing Requirement 1.5. Reliability's top priority is restoration of service. Forensics in a recovery mode may not support BES reliability and requiring such actions may negatively impact the BES Cyber System restoration process.

Regarding CIP-009-5, the Applicability sections of CIP-002-5 through CIP-011-5 should be consistent. Note that CIP-005-5 and CIP-006-5 sections 4.2.2 are different from the other Standards.

The capitalized term “Facilities” in Section 4 needs to be clarified. Does this refer to the NERC Glossary of Terms or section 4.2? For example, see CIP-002-5 sections 4.1.2 and 4.2.1. This question applies to the Applicability sections of CIP-002-5 – CIP-011-5.

There are potential issues with implementation of CIP Version 4 versus CIP Version 5. As written, CIP Version 5 appears to have some requirements that would be enforceable on the effective date and there may be a need for an implementation and/or conversion timeframe. The words in the Standards Requirements appear to be at odds with the Implementation Plan and clarity is needed. Additionally, there is concern with the need to be “compliant” with requirements that simply rely on documentation. Documentation is not a mechanism to ensure reliability and/or security of the bulk power system. An approach that should be considered is to have documentation “requirements” in a guidance document rather than in the requirements in the standard.

39. CIP-009-5 R2 states "Each Responsible Entity shall implement one or more processes that collectively address the applicable items in *CIP-009-5 Table R2 – Recovery Plan Implementation and Testing."* The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R2 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: Recommend that 2.1 be implemented 180 days from the effective date of the Standard.

For 2.1, request clarification, is "full operational exercise" the same as "functional exercise" as described in the rationale?

For 2.1 and 2.3 of Table R2 recommend removing "initially upon the effective date of the standard" because it will lead to forcing an Entity to be compliant with two Versions of the Standard at the same time. The increased demands placed upon Entities to be compliant with Version 5 will make it very difficult to become compliant when going from Version 4 to Version 5 within the time frames specified. Grandfathering is not considered.

For 2.2, request clarification that "any information" may be a sample and not all or each type of information. Does backup media include all media used in the recovery process such as vendor media? What does current configuration mean, as this may never be current?

In 2.3, request 1) a definition of "operational exercise" and 2) clarification of "representative environments". What is the scope, all network devices, systems and items that make up the BES Cyber System? This appears to be a new requirement as paper drill does not appear to be supported. Recommend this shall be implemented 180 days from the effective date of the Standard.

40. CIP-009-5 R3 states "Each Responsible Entity shall maintain each of its recovery plans in accordance with each of the applicable items in *CIP-009-5 Table R3 – Recovery Plan Review, Update and Communication*." The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R3 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: For 3.1 recommend 1) removing “or when BES Cyber Systems are replaced” as it addressed in CIP-009 R3.4 and 2) removing “and document any identified deficiencies or lessons learned” as they are addressed in CIP-009 R3.2 and R3.3.

For 3.1 of Table R3, recommend removing “initially upon the effective date of the standard” because it will lead to forcing an Entity to be compliant with two Versions of the Standard at the same time. The increased demands placed upon Entities to be compliant with Version 5 will make it very difficult to become compliant when going from Version 4 to Version 5 within the time frames specified. Grandfathering is not considered.

Request that 3.3 be updated to be consistent with CIP-008 R3.3 for sixty days.

Recommend that 3.4 be referenced by CIP-009 R3.1.

Request CIP-008 R3.5 language be consistent with CIP-009 R3.5.

41. Do you agree with the proposed Violation Risk Factors and Violation Severity Levels for CIP-009-5? If not, please provide suggested improvements on the proposed VRFs and VSLs.

☐ Yes

☐ No

Comments:

42. CIP-010-1 R1 states “Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable items in *CIP-010-1 Table R1 – Configuration Change Management*.” The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R1 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: Recommend changing 1.3 to avoid double jeopardy. Change "Update the baseline configuration and other documentation required by a NERC CIP Standard, including identification and categorization of the BES Cyber Systems, as necessary within 30 calendar days of completing the change." to "Update the baseline configuration as necessary within 30 calendar days of completing the change approved in 1.2."

For 1.1, 1.2, 1.3 and 1.4, recommend changing the Requirements to be consistent with their Applicability --- from "For a change to the BES Cyber System" to "For a change to the BES Cyber System or Associated Systems or Associated Assets".

Recommend removing "High Impact BES Cyber Systems" from 1.4's Applicability since these are covered by 1.5 which is a higher threshold.

Regarding CIP-010-1, the Applicability sections of CIP-002-5 through CIP-011-5 should be consistent. Note that CIP-005-5 and CIP-006-5 sections 4.2.2 are different from the other Standards.

The capitalized term “Facilities” in Section 4 needs to be clarified. Does this refer to the NERC Glossary of Terms or section 4.2? For example, see CIP-002-5 sections 4.1.2 and 4.2.1. This question applies to the Applicability sections of CIP-002-5 – CIP-011-5.

There are potential issues with implementation of CIP Version 4 versus CIP Version 5. As written, CIP Version 5 appears to have some requirements that would be enforceable on the effective date and there may be a need for an implementation and/or conversion timeframe. The words in the Standards Requirements appear to be at odds with the Implementation Plan and clarity is needed. Additionally, there is concern with the need to be “compliant” with requirements that simply rely on documentation. Documentation is not a mechanism to ensure reliability and/or security of the bulk power system. An approach that should be considered is to have documentation “requirements” in a guidance document rather than in the requirements in the standard.

43. CIP010-1 R2 states “Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable items in *CIP-010-1 Table R2 – Configuration Monitoring.”* The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R2 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: Recommend removing "where technically feasible" from 2.1 since the remaining words should not need an exception.

44. CIP-010-1 R3 states “Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable items in *CIP-010-1 Table R3– Vulnerability Assessments*.” The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R3 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

    ☐ Yes

    ☒ No

    Comments: For 3.1 and 3.2 of Table R3 recommend removing “initially upon the effective date of the standard” because it will lead to forcing an Entity to be compliant with two Versions of the Standard at the same time. The increased demands placed upon Entities to be compliant with Version 5 will make it very difficult to become compliant when going from Version 4 to Version 5 within the time frames specified. Grandfathering is not considered.

    Recommend changing 3.2 from "in a production environment" to "in a production environment, or a test environment" to allow Entities more flexibility in meeting this Requirement.

45. Do you agree with the proposed Violation Risk Factors and Violation Severity Levels for CIP-010-1? If not, please provide suggested improvements on the proposed VRFs and VSLs.

    ☐ Yes

    ☐ No

    Comments:

46. CIP-011-1 R1 states “Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable items in *CIP-011-5 Table R1 – Information Protection*.” The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R1 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

    ☐ Yes

    ☒ No

    Comments: Request clarification on 1.1. Some interpret this Requirement as what is the Entity's process for identifying BES Cyber Systems Information. If correct, the Measure should be "show me the methodology (document)." Others interpret these Measures as labeling BES Cyber System Information.

Recommend removing "initially upon the effective date of the standard" from 1.3 of Table R1 because it will lead to forcing an Entity to be compliant with two Versions of the Standard at the same time. The increased demands placed upon Entities to be compliant with Version 5 will make it very difficult to become compliant when going from Version 4 to Version 5 within the time frames specified. Grandfathering is not considered.

Regarding CIP-011-1, the Applicability sections of CIP-002-5 through CIP-011-5 should be consistent. Note that CIP-005-5 and CIP-006-5 sections 4.2.2 are different from the other Standards.

The capitalized term "Facilities" in Section 4 needs to be clarified. Does this refer to the NERC Glossary of Terms or section 4.2? For example, see CIP-002-5 sections 4.1.2 and 4.2.1. This question applies to the Applicability sections of CIP-002-5 – CIP-011-5.

There are potential issues with implementation of CIP Version 4 versus CIP Version 5. As written, CIP Version 5 appears to have some requirements that would be enforceable on the effective date and there may be a need for an implementation and/or conversion timeframe. The words in the Standards Requirements appear to be at odds with the Implementation Plan and clarity is needed. Additionally, there is concern with the need to be "compliant" with requirements that simply rely on documentation. Documentation is not a mechanism to ensure reliability and/or security of the bulk power system. An approach that should be considered is to have documentation "requirements" in a guidance document rather than in the requirements in the standard.

47. CIP-011-1 R2 states "Each Responsible Entity shall implement one or more documented processes that collectively include the applicable items in *CIP-011-5 Table R2 – Media Reuse and Disposal*." The requirement then proceeds to define the requirement parts in the table. Do you agree with the proposed Requirement R2 and its parts? If not, please explain why and provide specific suggestions for improvement with reference to the appropriate main requirement or part number.

☐ Yes

☒ No

Comments: Request that footnote 2 in 2.1 be moved into that Requirement.

48. Do you agree with the proposed Violation Risk Factors and Violation Severity Levels for CIP-011-1? If not, please provide suggested improvements on the proposed VRFs and VSLs.

☐ Yes

☐ No

Comments:

49. Do you agree with the proposed implementation plan? If so, please explain and provide specific suggestions for improvement.

☐ Yes

☒ No

Comments: The table label Scenario of Unplanned Changes is for unplanned changes after the effective date. If true, the surrounding words should explicitly state so. Otherwise, this Scenario table is confusing because it repeatedly uses 12 months while the earlier text uses 18 months.

Due to the CIP version 4 and version 5 implementation cycles, there is a lack of understanding as to what needs to be implemented, leading to uncertainty as to how long an implementation period would be needed. It is unrealistic to expect entities to begin implementing Version 4 requirements and then have to implement Version 5 requirements within a very "narrow" window.

Since Version 4 is not FERC approved, there is the possibility of Version 4 being effective while version 5 is in implementation. Version 4 may only be effective for a few months.

A summary of comments applicable to more than one standard: .

- Recommend removing "initially upon the effective date of the standard" from 1.3 of Table R1 because it will lead to forcing an Entity to be compliant with two Versions of the Standard at the same time. The increased demands placed upon Entities to be compliant with Version 5 will make it very difficult to become compliant when going from Version 4 to Version 5 within the time frames specified.
- Request that Applicability sections of CIP-002-5 – CIP-011-5 be consistent. Note CIP-005-5 and CIP-006-5 sections 4.2.2 are different from other Standards.
- Request clarification of the capitalized term "Facilities." Does this refer to the NERC Glossary of Terms or section 4.2? For example, see CIP-002-5 sections 4.1.2 and 4.2.1, and note this question applies to the Applicability sections of CIP-002-5 – CIP-011-5.

A fiftieth question should have been included in this comment form asking for general comments or concerns. A question asking general comments should be included as part of every comment form posted to the industry.

From: Wendy Kinnard
To: Wendy Kinnard
Subject: NERC Announcement: Slides Posted - Project 2008-06 Cyber Security Order 706 - December 13, 2011
Date: Thursday, December 15, 2011 5:11:12 PM

Slides Posted

Project 2008-06 Cyber Security Order 706

Draft CIP Standards Version 5 Balloting and Comment Process Webinar
December 13, 2011

Click here for: Streaming Webinar
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For more information or assistance, please contact Wendy Kinnard (via email) or at (404) 446-9735.

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Questions and Answers for the January 5 and 20, 2012 Webinars Order 754 – Data Request The Study of Single Point of Failure

Intent of the Request for Data or Information

Please provide the intent of the study. Is it to look at the impact of slower than normal clearing for bus and close-in faults?

The intent of the Request for Data or Information is to identify whether there is a reliability concern associated with the assessment of single points of failure on Protection Systems. The concern identified in Order No. 754 is not limited to specific fault types; however, the Request for Information or Data is focused on bus faults with delayed clearing to minimize the burden on entities while collecting sufficient data to assess the potential scope of the reliability concern if one does exist. The owner will determine if single points of failures exist in the Protection Systems on buses, lines, transformers, and shunt devices at the substation and how these failure modes impact the clearing times. The simulated bus faults are representative of close-in faults on each connected Element, but the Request for Data or Information does not require close-in bus faults be simulated.

Please describe what will happen after the requested data has been submitted? For example, will NERC be analyzing, creating a report, and recommending corrective actions for the industry?

NERC's Reliability Assessment and Performance Analysis group will evaluate the data to determine the extent to which single point of failure of protection systems may have a negative impact on reliability. The evaluation will aid in determining steps, if any, to improve reliability as well as support an informational filing to FERC in response to Order No. 754.

It seems that the existing TPL standards are sufficient to cause transmission planners to evaluate system reliability without the need for the data requested. What area in the data request is not included in the existing TPL standards?

The existing TPL standards do not establish specific system performance standards for three-phase faults accompanied by a Protection System failure. Single-line-to-ground faults frequently evolve to a multi-phase fault when fault clearing is delayed due to a Protection System failure. This Request for Data or Information will provide data on the extent to which delayed clearing could lead to a significant system disturbance such as those identified in the March 2009 NERC Industry Alert. In cases where delayed fault clearing could result in a similar disturbance, the Request for Data or Information requires reporting of attributes of Protection

Systems and station dc supplies to assist in understanding the extent to which exposure exists to such disturbances.

Is the purpose of collecting transmission line redundancy information to find those areas where delayed clearing exists?

No. Delayed clearing of faults in and of itself does not create a reliability concern. The intent of the study is to identify where delayed clearing results in system performance that could lead to a significant system disturbance such as those identified in the March 2009 NERC Industry Alert. In cases where delayed fault clearing could result in a similar disturbance, the Request for Data or Information requires reporting of attributes of Protection Systems and station dc supplies to assist in understanding the extent to which exposure exists to such disturbances.

Applicability to Entities

To which NERC registrations does this request apply to? Does it only apply to Transmission Planners?

Will Transmission Owners and Generator Owners have to fill out a survey?

This Request for Data or Information identifies the Transmission Planner as the entity responsible for submitting the requested data. Transmission Owners and Generator Owners will not need to submit data directly to NERC. However, Transmission Owners and Generator Owners are expected to provide to their Transmission Planner(s) any information that is necessary for the Transmission Planner to respond to the Request for Data or Information.

Will the Request for Data or Information be sent only to registered Transmission Planners, or also to the Generator Owners and Transmission Owners?

The Request for Data or Information will be sent to Generator Owners and Transmission Owners to make them aware they are expected to provide to their Transmission Planner(s) any information that is necessary for the Transmission Planner to respond to the Request for Data or Information.

Is it necessary to collect generator data? The failure of generator protection is most likely to result in only the loss of the generator, which is already evaluated as Category B or Category C contingencies. Priority should be to collect Transmission Owner data, which will reduce the amount of effort and data to be collected.

The only data that will be collected from Generator Owners is related to generator step-up (GSU) transformers. The majority of data will be collected from Transmission Owners. The Request for Data or Information includes all Facilities connected to buses that meet the criteria in Table A, because a fault on any of the connected Facilities accompanied by a Protection System failure would have the same potential impact on system reliability.

What are the manpower burden and cost implications for Generator Owners? This seems extremely onerous for small generating stations

The burden for Generator Owners will not be significant as the only data the Generator Owner must provide to their Transmission Planner(s) is related to their generator step-up (GSU) transformers. The burden for Generator Owners will be proportional to the number of generators they have connected to buses that meet the criteria in Table A.

What specifically you are expecting from Generation Owners other than providing information to the Transmission Planners on the generator step-up (GSU) transformer protection?

Providing information to the Transmission Planners on the generator step-up (GSU) transformer protection is the extent of the expectation for Generator Owners.

Is the Protection Engineering Group defined as part of the Transmission Owner/Generator Owner or could it also be considered part of the Transmission Planner?

Whether a protection engineering group is part of a Transmission Owner, Generator Owner, or Transmission Planner will depend on the functions for which each entity is registered. Per the NERC Functional Model the Transmission Owner or Generator Owner has responsibility for Protection Systems associated with their Facilities and as part of this Request for Data or Information they are responsible for submitting data to their Transmission Planner. This reporting is required regardless of whether the Transmission Owner or Generator Owner is part of the same company as the Transmission Planner.

Applicability to the Bulk Electric System (BES)

Please confirm whether the Request for Data or Information is limited to the BES

The Request for Data or Information requests information for all Facilities operated at 100 kV or higher that meet the criteria in Table A, regardless of whether the bus would be considered part of the Bulk Electric System under the existing NERC glossary definition.

Presently, in the NPCC footprint the BES is considered to be limited to only the NPCC Bulk Power System (BPS), as defined by the A-10 test. Would this request for information be limited to the BPS buses for entities in NPCC?

The Request for Data or Information is independent of how any region presently defines the Bulk Electric System. If a bus meets the criteria in Table A, the Transmission Planner should include the bus per the method in the Request for Data or Information regardless of whether it meets the regional definition of a Bulk Electric System Element.

What if there is a 115 kV bus that meets the criteria in Table A that is not part of the BES?

If a 115 kV bus meets the criteria in Table A, the Transmission Planner should include the bus per the method in the Request for Data or Information regardless of whether it is considered to be part of the BES.

Responsibilities of Applicable Entities

Will the Request for Data or Information be sent to Canadian registered entities? Page 1 of the overview document states "The purpose of this survey is to solicit data and information from each Transmission Planner in the United States to . . ."

The data request will be sent to all registered entities in the United States and Canada. The overview in the final Request for Data or Information will be corrected.

Will this responding to this data request be mandatory?

Responding to the data request is mandatory for registered entities in the United States. It is not mandatory for registered entities in Canada, but Canadian entities are strongly encouraged to submit data so that decisions regarding this concern are based on complete data across North America.

Should Generator Owners and Transmission Owners wait until contacted by their Transmission Planner to take action?

The first step in the method defined in the Request for Data or Information is based on the Transmission Planner meeting with the Generator Owners and Transmission Owners in its transmission planning area. However, Generator Owners and Transmission Owners are not prohibited from beginning to collect the information described in the Request for Data or Information prior to being contacted by their Transmission Planner.

Are entities expected to review Protection System schematics and wiring diagrams to identify all possible single points of failure?

No, entities are expected to only review Protection System schematics and wiring diagrams for Facilities identified by the Transmission Planner in step 7. For the purposes of the Request for Data or Information it is not necessary to identify every single point of failure. Entities only need to review these diagrams to identify whether a single point of failure exists for each of the attributes in Table B. If a single point of failure is identified, further review is not required for that Element.

Definition of Single Point of Failure

Please define the term "single point of failure"

In general terms a single point of failure exists when failure of a single component can affect the operation of all protection systems applied on an Element(s). For the purposes of this Request for Data or Information, single point of failure would be reported whenever a protection system component does not meet one of the attributes defined in Table B.

Will the Request for Data or Information include single points of failure due to geomagnetic disturbance or other high impact, low frequency events?

No, this Request for Data or Information does not address single point of failure associated with geomagnetic disturbances or other high impact-low frequency (HILF) events.

Will the Request for Data or Information include single points of failure during maintenance periods which can be 2-3 days?

No, this Request for Data or Information only addresses conditions with Protection Systems in their normal operating state. It is recognized that single points of failure may exist during maintenance and testing that do not occur during day-to-day operation, but these single points of failure are not the subject of this Request for Data or Information.

We suspect that many single points of failure will include station batteries, VT's, and CT's. Is this what you are also expecting to find?

The intent of the Request for Data or Information is to identify whether there is a reliability concern associated with the assessment of single points of failure on Protection Systems. The data collected will enable NERC to assess whether there is a reliability concern and if so, whether it is related to specific Protection System components. The data collection for station dc supplies, voltage transformers, and current transformers is designed to avoid skewing the data. For example, the request for voltage transformers and current transformers excludes common primary windings and the request for station dc supply requests additional information regarding alarming when only one station battery is used.

Simulations/Relation to Reliability Standards

What type of studies is the Transmission Planner required to perform – power flow, transient stability?

The method defined in the Request for Data or Information requires a transient stability simulation to identify the system performance for a three-phase fault. An explicit reference will be added to the final Request for Data or Information.

Don't the simulations defined in the data request align with an "extreme event" per TPL-001-2 which is not a design requirement? Why wouldn't non-performance be expected when the system is evaluated beyond design criteria?

It is correct that contingencies to be simulated for this Request for Data or Information would be classified as Category D contingencies in the existing Transmission Planning studies defined in TPL-004-0 and as extreme events in the new TPL-001-2 that has been filed with FERC. The simulated system performance under TPL-004-0 and TPL-001-2 would not be required to meet specific performance requirements. For this reason it is possible that simulated performance will not meet the requirements in Table C. The purpose of this assessment is to identify the extent to which such contingencies could result in system performance that could lead to a significant system disturbance such as those identified in the March 2009 NERC Industry Alert, and where the potential does exist for such system performance, the extent to which Protection Systems are designed to mitigate exposure to such system performance. This information will be used to assess whether there is a reliability concern associated with the assessment of single points of failure on Protection Systems.

The performance requirements for this data request appear more stringent than the NERC Reliability Standards, which require performance for a single-phase fault with delayed clearing. If a bus fault doesn't meet the three-phase fault test, will it be repeated for a single-phase fault to see if it meets the NERC TPL Standards?

No. This Request for Data or Information will not request any information associated with whether an entity complies with exist8ing NERC Reliability Standards. The requested data will be used to identify where delayed clearing results in system performance that could lead to a significant system disturbance such as those identified in the March 2009 NERC Industry Alert. In cases where delayed fault clearing could result in a similar disturbance, the Request for Data or Information requires reporting of attributes of Protection Systems and station dc supplies to assist in understanding the extent to which exposure exists to such disturbances. This data will aid in determining steps, if any, to improve reliability as well as support an informational filing to FERC in response to Order No. 754.

TPL-001-2 does not consider failure of a Protection System anymore; it considers failure of a non-redundant relay in P5. This appears to indicate that failure of a protection system is beyond the design criteria.

The new TPL-001-2 that has been filed with FERC requires consideration of a failure of specified protective relays and tripping relays under contingency P5. It is correct that the scope of this Request for Data or Information exceeds the criteria proposed in TPL-001-2. The purpose of this assessment is to identify the extent to which contingencies could result in system performance that could lead to a significant system disturbance such as those identified in the March 2009 NERC Industry Alert, and where the potential does exist for such system performance, the extent to which Protection Systems are designed to mitigate exposure to such system performance. This information will be used to assess whether there is a reliability concern associated with the assessment of single points of failure on Protection Systems.

Has the NPCC A-10 BPS Criteria document been used as a reference in developing the testing method? Can entities use existing A-10 tests already performed within NPCC in fulfilling this request?

The NPCC A-10 document was not used as a reference in developing the testing method, but there are similarities between the method defined in the Request for Data or Information and the NPCC A-10 criteria document. Registered entities in NPCC will need to compare the method and results of their analyses performed in accordance with the NPCC criteria and determine the extent to which these simulations can be used to fulfill the requirements of this Request for Data or Information.

In the NPCC region, there is a Directory that discusses system protection design criteria. However, these criteria apply only to what NPCC defined as its Bulk Power System. Are you familiar with the Directory (i.e., Directory 4) and does this document addresses certain components of the request?

We are familiar with the criteria in NPCC Directory 4 and there are many similarities between the Protection System attributes defined in Table B of the Request for Data or Information and Directory 4. There also are differences such as Table B does not require consideration of physical separation of Protection System components. Registered entities in NPCC will need to compare their as-built Protection System designs against the attributes in Table B.

Will guidance be provided to specify which seasonal model(s) would be used for the simulations in steps 2 and 6 of the method? Would analysis of only the horizon year summer peak planning model be adequate for this screening?

Additional guidance regarding the study-year and season to be modeled will be provided in the final version of the Request for Data or Information.

In the case where the Protection System owner has a lot of transmission projects underway, should the system assessment be performed "as-is" or how it will be by the end of the reporting period. Otherwise it will present a moving target.

The Protection System information that Transmission Owners and Generator Owners submit to the Transmission Planner should be consistent with the year and season modeled by the Transmission Planner. Additional guidance regarding the study-year and season to be modeled will be provided in the final version of the Request for Data or Information.

Will a single point of failure be considered as a Category B contingency?

No. FERC Order No. 754 approved the interpretation of TPL-002-0 that states single points of failure in Protection Systems are not considered under Category B.

Method

Is the general concept to test ONLY buses in Table A and evaluate Table B based on the buses that meet Table A?

Attempting to summarize in one sentence the method defined in the Request for Data or Information neglects many important steps. It is important that entities follow the detailed method so all data submitted by the Transmission Planners will be on a common basis.

Rather than perform numerous studies, would it not be easier and faster to determine where redundant protection systems are lacking?

The Request for Data or Information has been designed to minimize the overall effort by registered entities and burden on the industry. While identifying where redundant Protection Systems exist would minimize effort for Transmission Planners, using an iterative approach minimizes the overall effort by both the Transmission Planners and the Transmission Owners and Generator Owners and introduces a performance assessment.

In the interest of minimizing impact to Transmission Owners and Generator Owners at the outset of the evaluation process, why is step 1 needed? What percentage of buses do you expect to exclude in this step? Would it not be simpler to test all buses that meet Table A and then examine exclusions using Table B on the list of buses that fail the criteria? Seems it would further reduce entity burden.

While this approach would minimize burden on Transmission Owners and Generator Owners, the method was developed with stakeholder input from the affected groups of entities to minimize the overall burden on industry. Step 1 is intended to take advantage of the Transmission Owner's and Generator Owner's at-hand knowledge about the Protections Systems and should minimize the number of buses to be tested by the Transmission Planner without significant burden on the Transmission Owners and Generator Owners. The number of buses that may be excluded in step 1 will vary depending on existing design practices, but may be significant in some areas.

Step 1 of the evaluation method excludes buses to be tested if the Protection System meets the attributes in Table B. However the wording in Step 2 requires the Transmission Planner to study those busses identified in Step 1 "based on the Owner confirming that the protective system meets the attributes in Table B." These two steps appear to be contradictory.

The intent of step 1 is to create a list of buses to be tested starting from a list of all buses that meet the criteria in Table A, and removing from the list any buses for which Protection Systems on all connected Facilities meet the attributes for all categories in Table B, "Protection System Attributes to be Evaluated," based on the Transmission Owner's or Generator Owner's "as-built" knowledge of the Protection System(s). This intent is not reflected in the posted draft of the Request for Data or Information, leading to the identified contradiction. Steps 1 and 2 of the process will be revised in the final Request for Data or Information to rectify this contradiction.

Step 1 of the evaluation method calls for identifying transformers with through-fault protection. Please confirm whether a transmission transformer differential protection that trips remote terminals via direct transfer trip (DTT) is considered to provide through-fault protection.

Through-fault protection is applied to protect a transformer from the effects of through-fault current for a fault external to the transformer. Since the DTT in this case would operate for faults internal to the transformer differential zone, this would not be considered through-fault protection.

Step 2 and step 6 of the evaluation method requires simulation of a three-phase bus fault. What about end-of-line faults for which remote backup may not operate? For generator step-up (GSU) transformers, is the fault location of concern limited to an external fault on the high-voltage side or does it include internal transformer faults?

For the purpose of this Request for Data or Information it is not necessary to consider end-of-line faults. The intent of the Request for Data or Information is to identify whether there is a reliability concern associated with the assessment of single points of failure on Protection Systems. The concern identified in Order No. 754 is not limited to specific fault types; however, the Request for Information or Data is focused on close-in faults with delayed clearing to minimize the burden on entities while collecting sufficient data to assess the potential scope of the reliability concern if one does exist.

This Request for Data or Information only requires simulation of bus faults as described in the method, which address faults on the terminals of equipment (e.g., the high-voltage side of a generator step-up (GSU) transformer). Internal transformer faults are not considered as part of this Request for Data or Information to minimize the burden on entities while collecting sufficient data to assess the potential scope of the reliability concern if one does exist.

Is it possible to clarify how to treat, for example, a breaker-and-a-half bus within the testing method? Please confirm that the assumption in step 2 should be that no local breakers would operate?

In the testing method the Transmission Planner would model fault clearing based on no local breakers operating. The Transmission Owner or Generator Owner would determine how single points of failure on the protection systems applied on the breaker–and-a-half configuration would impact remote clearing times. Additional explanation will be added to the final Request for Data or Information.

In step 2 and step 6, if the Protection System design includes fully redundant protection schemes but the breakers only have a single trip coil with a breaker failure scheme, is it necessary for the Transmission Planner to simulate tripping remote terminals of all lines, or can tripping be limited to only those lines associated with the breaker failure scheme operation? Can local breaker failure be considered during the testing, since battery failure is excluded?

The simulation specified in the Request for Data or Information was developed to be independent of the Protection System design and intended to consider tripping of all connected

circuits at the remote terminals. This method has been developed to minimize the burden on entities while collecting sufficient data to assess the potential scope of the reliability concern if one does exist. Simulation of remote clearing would be necessary when a single point of failure would prevent both breaker tripping and initiation of breaker failure protection. However, this question raises for consideration whether breaker failure protection should be considered when the only single point of failure of the Protection Systems connected to a given bus are the breaker trip coils. In this case consideration could be given to modifying the method to allow the Transmission Planner to assess performance based on the actual protection system operation or the tripping as performed by the breaker failure scheme. Entities who believe breaker failure protection should be considered in the evaluation method may submit comments on this subject during the 45-day comment period that ends on February 6, 2012.

In step 2 and step 6 when considering transformer protection, is it correct to assume that transformer fault clearing should be simulated based on how the transformer protection would respond for the simulated three-phase bus fault? Specifically if the bus fault is in the transformer differential zone should the transformer differential protection be assumed to provide through-fault protection for the simulated bus fault?

No, for the purposes of this Request for Data or Information the transformer differential should not be considered to provide through-fault protection. The bus fault defined in the testing method has been selected to minimize the burden on Transmission Planners and is representative of a close-in fault on any Element connected to the bus. While the transformer differential would operate for the bus fault, it would not operate for close-in faults on the other Facilities connected to the bus. This point will be clarified in the final Request for Data or Information.

If the Request for Data or Information excludes transformers with only one winding operated at 100 kV or higher (a two-winding step-down transformer for example), how does the evaluation method consider a fault in the transformer protection zone that is not detected by the bus protection. A specific example would be dual bus protection schemes and a single transformer protection scheme with the overlap point at the bus – supplies to such a transformer could be in the transformer zone but the impact on the system would be no different than a fault in the bus zone.

The Request for Data or Information excludes transformers with only one winding operated at 100 kV or higher, that are not generator step-up (GSU) transformers, only for the purpose of identifying buses that meet the criteria in Table A. These transformers are to be included in the data provided regarding Protection Systems that meet the attributes in Table B if they are connected to a bus identified by the Transmission Planner in step 7. The bus fault defined in the testing method has been selected to minimize the burden on Transmission Planners and is representative of a close-in fault on any Element connected to the bus. While the transformer differential would operate for the bus fault, it would not operate for close-in faults on the other Facilities connected to the bus and it would be considered to not operate in the simulation. This point will be clarified in the final Request for Data or Information.

Would bus protection redundancy only be an issue if the bus truly is a straight bus or breaker-and-a-half bus?

Failure of bus protection would result in remote clearing of Elements for any physical configuration in which bus protection is applied (e.g., straight bus, breaker-and-a-half, and double-bus-double-breaker). For the purpose of providing data for the "Buses" tab in the reporting template, information on bus protection attributes would not be relevant for bus configurations in which bus protection is not applied, as may be the case for a ring bus depending on design practices.

Table A

When Table A refers to circuits, e.g., the second row refers to "Buses operated at 100 kV to 200 kV with 6 or more circuits," does circuits mean transmission lines or elements?

As described in the note below Table A, circuits include transmission lines, transmission transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher, and generator step-up transformers.

Would a substation with three circuits connected at 345 kV and five circuits connected at 115 kV meet the criteria in Table A?

The substation described would not require testing of the 345 kV bus. Testing of the 115 kV bus would be required only if a fault on the bus will result in 300 MW or more of consequential load loss as a result of remote clearing.

A 100kV line could be a radial line. Is this counted as a circuit?

Under the present draft of the Request for Data or Information a radial line at any voltage 100 kV or higher would be counted as a circuit for the purpose of identifying buses that meet the criteria in Table A. Entities who believe radial lines should be excluded may submit comments on this subject during the 45-day comment period that ends on February 6, 2012.

When counting circuits for Table A, are transformers counted as circuits. When looking at a 115 kV bus, if there are four lines and two distribution transformers connected, does that meet the threshold of Table A?

For the purposes of identifying buses that meet the criteria in Table A, transformers are counted as circuits only if the transformer is (i) a transformer with the primary terminal and at least one secondary terminal operated at 100 kV or higher, or (ii) a generator step-up (GSU) transformer. A bus with four 115 kV transmission lines and two distribution transformers that step down to a voltage level below 100 kV would have four circuits connected. This example would meet the criteria in Table A only if a fault on the bus will result in 300 MW or more of consequential load loss as a result of remote clearing.

For a substation with an autotransformer, would Table A apply for each voltage level?

The reporting template applies for each voltage level at a substation that meets the testing requirements in Table A. For example, testing would be required at 500 kV and 230 kV for a substation with three 500 kV transmission lines, three 230 kV transmission lines, and a 500/230 kV autotransformer, because both the 500 kV and 230 kV buses would have four circuits connected as defined in Table A.

If a transformer has both sides connected at 100 kV or higher, when counting the 'number of circuits' is the transformer counted at both the high and low voltage 'buses' or just the high-side bus? For example, on slide 18, does transformer T1 count as a 'circuit' for both the 345 kV and the 138 kV bus?

A transformer connected to two buses at 100 kV or higher would be counted for determining whether each of the buses meet the criteria in Table A; i.e., the transformer would count as a circuit for the high-voltage bus and also would count as a circuit for the low-voltage bus. For example, Transformer T1 on slide 18 would be considered a circuit connected to the 345 kV bus and also as a circuit connected to the 138 kV bus.

Would the 115/25 kV distribution transformer in the ring bus example on slide 17 NOT be counted as a circuit connected to the 115 kV bus, thereby resulting in five applicable circuits, and thereby excluding the 115 kV bus?

The 115/25 kV transformer would NOT be counted as a circuit for the purpose of determining whether the 115 kV bus meets the criteria in Table A. However, the bus would be included as meeting the criteria since there are six circuits connected to the bus: five transmission lines and one 230/115 kV transformer.

In slide 17 is T3 counted as a circuit in applying Table A? Is it a 'step-down' transformer?

Transformer T3 on slide 17 is a step-down transformer supplying a customer's facilities and would not be counted as a circuit for the purpose of determining whether the 115 kV bus meets the criteria in Table A.

Is there a minimum size GSU to be counted as a circuit?

No, a minimum MVA threshold has not been established for identifying whether a generator step-up (GSU) transformer is to be counted as a circuit for the purposes of identifying buses that meet the criteria in Table A. Entities who believe an MVA threshold should be established may submit comments on this subject during the 45-day comment period that ends on February 6, 2012.

Do capacitor banks and reactors fall under the term "circuits" for Table A?

Capacitor banks and reactors are not considered to be circuits for the purposes of applying Table A. However, Protection System attributes are to be reported for buses that meet the criteria in Table A that are identified by the Transmission Planner in step 7.

It would be a good idea to give some example figures showing how to count up elements and determine whether a station is required to be analyzed or not.

Example figures will be added as an appendix to the Request for Data or Information to provide additional clarity.

Table B

How should entities consider single points of failure that may affect two or more systems of protection resulting from insufficient separation; e.g., redundant relays on a common rack, redundant control circuits in a common cable tray, conduit, duct bank, or redundant control circuits in a common multi-conductor cable?

For the purposes of the Request for Data or Information it is not necessary to consider physical separation of protection system components such as protective relays or dc control circuitry.

How should entities consider single points of failure if a line is protected by two relays, but the relays are identical? To be considered two independent protective relays must the relays be from two different manufacturers? Does the NERC Request for Data or Information consider this a single point of failure?

For the purposes of the Request for Data or Information it is not necessary to consider whether two protective relays associated with an Element are identical, or whether they have the same manufacturer or algorithm for fault detection.

Are two breaker trip coils required for independence?

Yes, for the purposes of this Request for Data or Information the dc control circuitry must include two trip coils to meet the Protection System attributes in Table B. However, depending on the failures mode and resulting trip times, two trip coils may not be necessary to meet performance requirements.

What about the failure of the communication box into which primary and redundant/backup protection systems terminate?

This would be considered a single point of failure for determining whether the Protection System meets the attributes for communication systems in Table B if communication between protective relays is needed to satisfy BES performance required in the existing Transmission Planning standards.

Table C

For the evaluation, what is meant by "could result in a potential reliability risk?" Does this mean cascading outages, voltage collapse, transient instability, violation of established SOL/IROLs, other?

For the purpose of this Request for Data or Information, a potential reliability risk would exist when the simulated system performance does not meet the performance measures in Table C.

Is the intent of these simulations to identify only system instability due to a potential single point of failure in the Protection System? The Request for Data or Information does not mention reliability concerns such as overload or low voltages? It appears that stability, not steady state, is applicable to this approach, correct?

The performance requirements for this Request for Data or Information were developed based on avoiding significant system disturbance such as those identified in the March 2009 NERC Industry Alert. Evaluation of thermal loading and voltage performance is not required. Transient stability analysis will be necessary to assess whether simulated system performance violates the requirements in Table C.

Are load shedding schemes allowed to maintain stability?

The draft Request for Data or Information does not prohibit modeling existing load shedding schemes that may operate in response to the simulated three-phase fault conditions. Entities may submit comments on this subject during the 45-day comment period that ends on February 6, 2012.

Regarding item 2 bullet 4 and Table C, how can these performance measures be exceeded? The "or more" language is confusing in items 2 and 3. Would it be better to state in item 2, bullet 5 that the results do not meet at least one of the performance measures?

Yes. This recommendation will be incorporated in the final version of the Request for Data or Information.

Why was 1000 MW of generation chosen as a criterion in Table C, especially if the system remains stable? Our largest power plant is greater than 1000MW, which is already covered under a NERC B

The 1000 MW threshold is based on Event Category 3 in the Phase 2 Field Test draft Electric Reliability Organization Event Analysis Process. Tripping a generator for a Category B single-line-to-ground fault is a less severe condition than loss of 2000 MW of generation in the Eastern or Western interconnection or 1000 MW of generation in the ERCOT or Québec interconnection resulting from a three-phase fault accompanied by a Protection System failure.

Could you provide a conceptual example of how one would identify the second performance measure in Table C which refers to island formation of 1,000 MW or higher.

Formation of an island in a stability simulation may be identified, for example, by monitoring the apparent impedance on transmission lines to identify whether lines may trip as the result of a power swing. When this occurs the contingency may be re-simulated with the line tripping and an assessment made of resulting islands. Transient stability programs include screening tools for such analyses. The Request for Data or Information does not specify how the Transmission Planners are to perform this assessment to allow them to utilize the techniques they find most useful.

Table D

Please define specifically what Table D means when referencing 'two independent station dc supplies.' If one has one charger, one set of batteries, with separate dc panels feeding the independent relay systems and trip coils, is that considered 'independent' dc supplies? This directly effects how Table B 'DC Control Circuitry" is used in selecting buses to be evaluated.

The station dc supply consists of a charger and battery, or other dc source that is used for powering the Protection Systems and used for tripping; it does not include the dc distribution panels. In the example provided, the one charger and one set of batteries would be a single dc source. For the purpose of the Request for Data or Information, the separate dc panels feeding the independent relay systems are part of the dc control circuitry. When applying Table B to determine whether a Protection System meets the attributes for independent dc control circuitry it is not necessary to consider the station dc supply. If in the example provided the dc control circuitry, auxiliary relays, and trip coils are independent, the dc control circuitry would meet the attributes in Table B regardless of the station dc supply. Considerations for the station dc supply are in a separate table to avoid influencing the buses to be evaluated. Additional clarification will be added to the Request for Data or Information.

What is the purpose of the dc supply attribute reporting? These attributes are not included in any of the simulations.

Station dc supply failures are not included in the screening to identify buses to be tested because two independent station dc supplies is believed not to be a common design practice. Rather than include station dc supply attributes in identifying buses to be tested, the Request for Data or Information requests reporting of station dc supply attributes separate from the Protection System attributes.

Reporting

Are the periodic status reports and data requests coordinated by the Regions, or are the reports going directly to NERC Staff?

Periodic status reports along with the actual data submittal will be directed to NERC. At the appropriate time(s) based on the schedule a web-based application will be made available for Transmission Planners to submit their reports and data.

The data gathered is highly critical to the operation of the power system. Who will have access to this data? How will it be secured from unintended access?

NERC will aggregate the data supplied by each entity for analysis. The result will not be entity specific and will be presented in such a manner as not to identify entities or vulnerabilities. In teams of access, the appropriate NERC staff will have access to the data for analysis and reporting. The collected data will be secured within NERC's secure resources.

Does the Request for Data or Information ask for the level of burden for the entities? This is not a question on the Comment Form.

The Request for Data or Information does not request entities to report on the level of burden for entities. To the extent registered entities believe the burden will be significant or require more time than proposed in the draft Request for Data or Information, entities may submit information on this subject during the 45-day comment period that ends on February 6, 2012.

The survey should include reporting on the attribute of Table B that causes the performance issue so that there can be a priority to rectify.

The intent of the Request for Data or Information is to identify whether there is a reliability concern associated with the assessment of single points of failure on Protection Systems. The method in the request has been designed to mitigate the burden on entities and as such will not provide information regarding which specific Protection System attributes may cause specific performance issues. However, the data collected will include the Protection System attributes where potential reliability risks exist to assist NERC in assessing whether there is a reliability concern and if so, whether it is related to specific Protection System components.

In the reporting template, is the tab labeled "Step Down Transformers" for reporting information on distribution transformers?

The tab labeled “Step-Down Transformers” would include reporting for distribution transformers that step voltage down from a voltage 100 kV or higher to a voltage below 100 kV. However, this tab is not exclusively for distribution transformers. This tab also will be used for collecting data on other transformers that step voltage down from a voltage 100 kV or higher to a voltage below 100 kV, such as those supplying sub-transmission networks, auxiliary power during start-up and shut-down of generators, or off-site power to nuclear generating stations. A clarifying note will be added to that tab.

What documentation is needed by NERC to prove a system is fully redundant and therefore should be excluded from the bus list?

Supporting evidence is not required to support responses to this Request for Data or Information.

Table B does not provide enough examples and detail to determine if protections system attributes that need to be evaluated meet single point of failure requirements in Table B? Will there be additional guidelines or appendices to clarify these details?

Examples will be added to the final version of the Request for Data or Information.

Schedule

When do you anticipate the actual data request will be due to NERC?

The requested data will be due to NERC 12 months after the Request for Data of Information is sent to registered entities. The anticipated due date will be on or around April 1, 2013.

The last page of the Request for Data or Information draft is a form which requests Transmission Planning Entity Contact Information. What is the deadline for this form? Is this the form that has to be filled out as acknowledgement of the request for data by the 2nd month of the schedule?

NERC will be providing the responsible entities an electronic method to enter their respective contact information concerning the data request by the 2nd month. Each entity may be provided an electronic approval process to complete their data submittal in the last 60 days of the period; however, each entity will be required to submit the approval form of the data request to NERC using the supplied address near the beginning.

The requirement is to accomplish this task in one year. If it takes Transmission Planning most of that time to identify the buses and elements that need to be reviewed, there would be little time left for the Transmission Owners and Generator Owners to finish their review. The Transmission Owners and Generator Owners may need additional time to accomplish their review beyond the one-year time frame.

The schedule in the draft Request for Data or Information is intended to provide Transmission Planners adequate time to work interactively with their Transmission Owners and Generator Owners. Entities that have concerns with the schedule may provide comments, including details of concerns and proposals for mitigation, during the 45-day comment period that ends on February 6, 2012.

General

Where on NERC's site will information be posted?

The streaming webinar and a copy of the presentation slides are posted on the NERC website at http://www.nerc.com/page.php?cid=1|83 under the tab titled "2012 Webinars." This page can be reached from the main NERC website page by clicking on the "Webinars" button on the right side of the page. Other information related to FERC Order No. 754 is posted on the NERC website at http://www.nerc.com/filez/standards/order_754.html.

Many of the hyperlinks in the Request for Data or Information do not work and URLs are not provided. It will be beneficial if they work.

The hyperlinks in the document will be updated in the final version of the Request for Data or Information. In the interim, the following hyperlinks and URLs are provided for the missing hyperlinks:

NERC SPCTF technical paper, Protection System Reliability – Redundancy of Protection: http://www.nerc.com/docs/pc/spctf/Redundancy_Tech_Ref_1-14-09.pdf.

NERC Reliability Standard TPL-001-2, Transmission System Planning Performance Requirements: http://www.nerc.com/files/TPL-001-2.pdf.

NERC Reliability Standard TPL-004-0, TPL-004-0 System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D): http://www.nerc.com/files/TPL-004-0.pdf.

Please confirm that the Request for Data or Information instructions have precedence over the notes in the data reporting template (Excel spreadsheet) if conflicts exists.

The instructions in the Request for Data or Information have precedence of the notes in the template. Entities who believe there are conflicts between the instructions in the Request for Data or Information and the reporting template may submit comments on this subject during the 45-day comment period that ends on February 6, 2012. NERC will address all identified conflicts prior to issuing the final Request for Data or Information.

The lead in at http://www.nerc.com/docs/standards/dt/Order_754_-_Data_Request_Outline_DRAFT_2011_12_01.pdf states "violations of applicable thermal or voltage ratings". Is the use of the term 'violations' correct in this context (what NERC performance criteria is being violated?)?

The referenced document was a working draft outline used during development of the Request for Data or Information. Subsequent to developing the referenced outline, the performance criteria were modified as presented in Table C. The Request for Data or Information does not require consideration of applicable thermal or voltage ratings.

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Draft CIP Standards Version 5

Balloting and Comment Process Webinar

Project 2008-06 Cyber Security Order 706
December 13, 2011

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Agenda

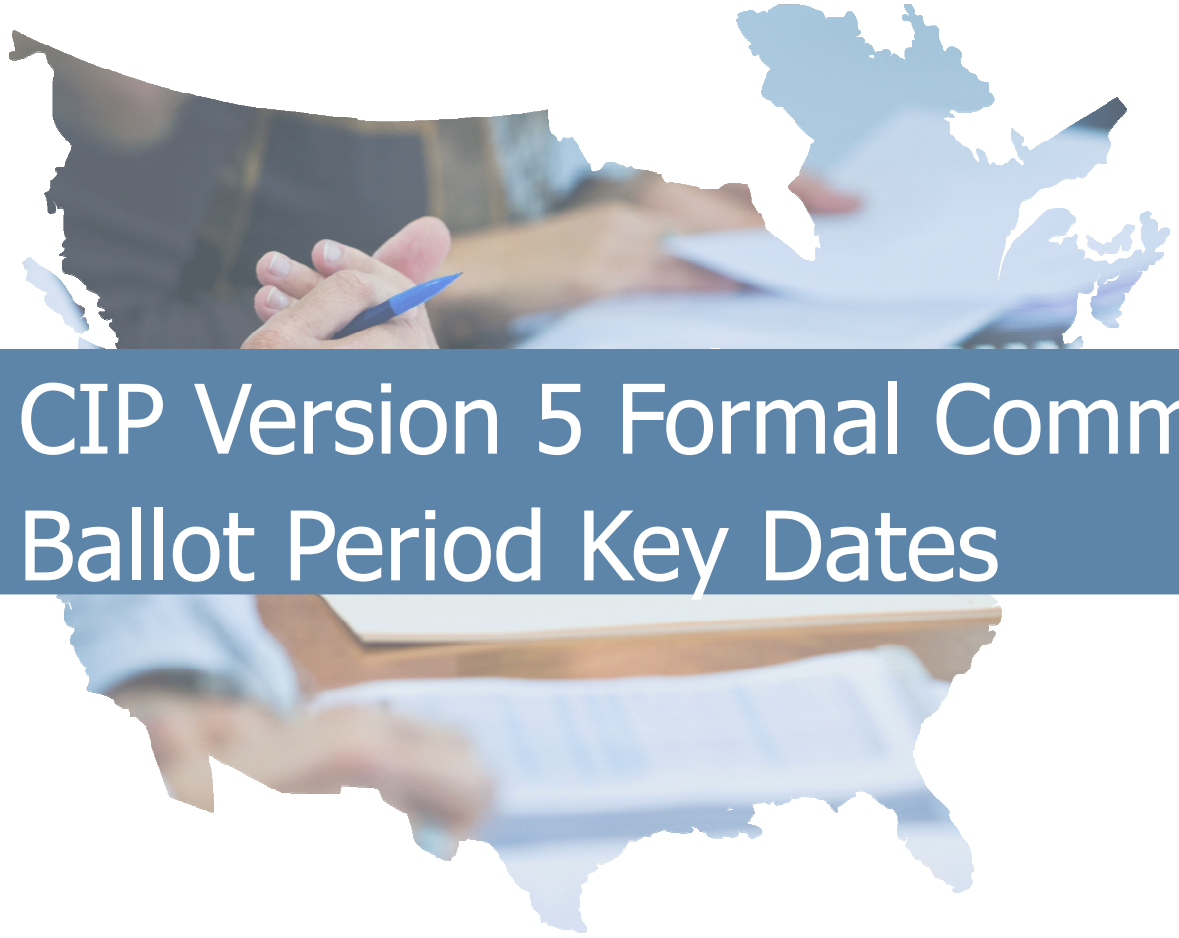
- Opening Remarks
- Version 5 Formal Comment and Initial Ballot Period Key Dates
- Review of NERC's Standards Process and CIP Version 5 Comment Form
- FAQs Related to CIP Version 5 Ballot Process
- Q&A

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Opening Remarks

- Presenters
  - Laura Hussey – NERC Standards Process Manager
  - Steven Noess – NERC Standards Development Advisor
- Webinar focused on standards process for CIP Version 5 posting. See www.nerc.com under "webinars" for technical webinars
  - Technical Webinar, part 1 of 2: November 15, 2011
  - Technical Webinar, part 2 of 2: November 29, 2011

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CIP Version 5 Formal Comment and Initial Ballot Period Key Dates

Comment and Ballot Period

- November 7, 2011 – January 6, 2012
  - Formal 60-day comment period
- November 7, 2011 – December 15, 2012
  - Ballot pool open
- December 16, 2011 – January 6, 2012
  - 12 initial ballots open

Join Ballot Pool

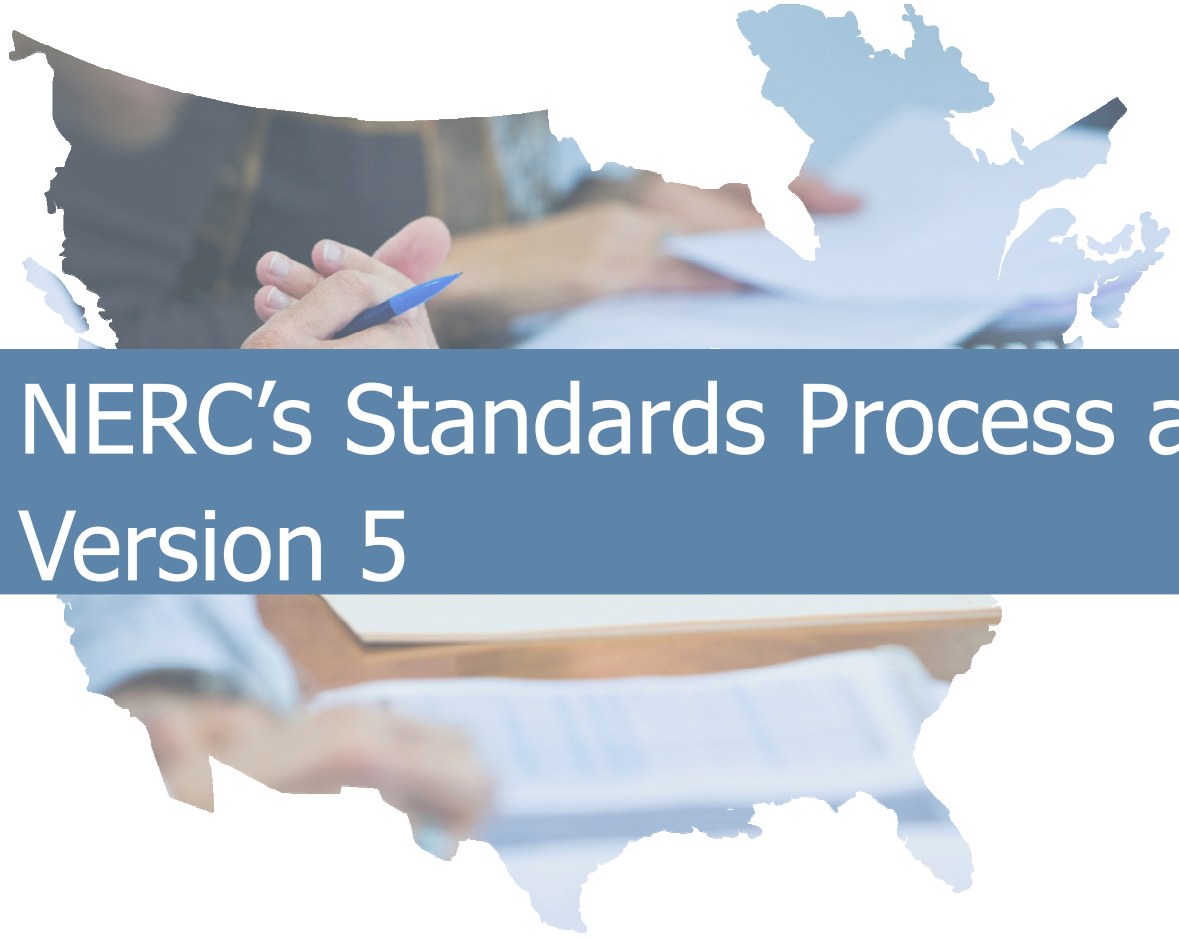
Supporting Materials Unofficial Comment Form (Word) Mapping Document CIP-002-4 CIP-003-4 CIP-004-4 CIP-005-4a CIP-006-4c CIP-007-4 CIP-008-4 CIP-009-4 Consideration of Comments from June 2010 Informal Comment Period Draft Consideration of Issues and Directives	Submit Comments>> Join Ballot Pool Info>> Join>>	 11/07/11 - 12/15/11
CIP Standards Version 5 Webinar Slides		08/24/2011
CIP Standards Version 5 Presentations - August 2011 SDT Meeting		08/17/11
CIP Standards Development Overview for FERC Technical Staff Meeting		07/28/11

*Registered Ballot Body and Segment Qualification Guidelines:
http://www.nerc.com/files/Development_of_RBB_and_Segment_Qualification_Guidelines.pdf

Long Term Schedule 2012

January 6 – March 26	• Consideration of comments
March 26 – April 27	• 30-day posting for comment and successive ballot
June 6 – 22	• Possible recirculation ballot

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NERC's Standards Process and CIP Version 5

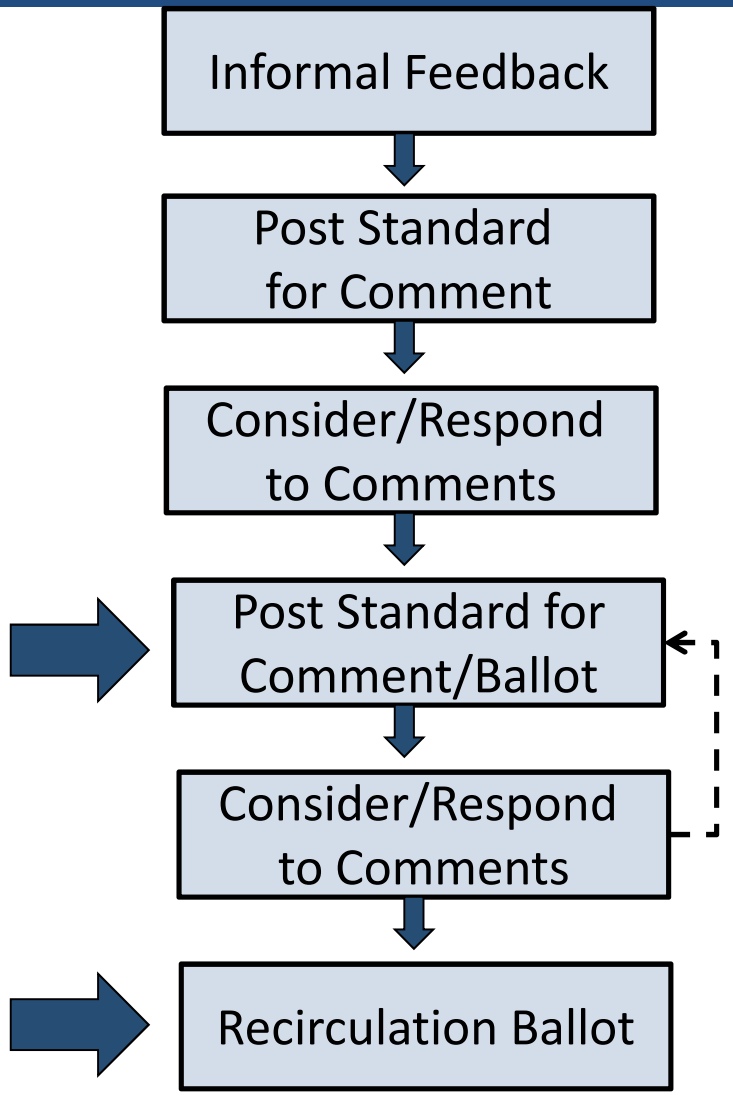
Stakeholder Consensus Process

New/Successive Ballot:

At this step, the standard is either "new" or significantly changed from the last version posted for comment/ ballot. The ballot record starts with no votes and no comments.

Recirculation Ballot:

At this step, there have been no significant changes to the standard from the last ballot. The ballot record starts with all votes and comments from the previous ballot.

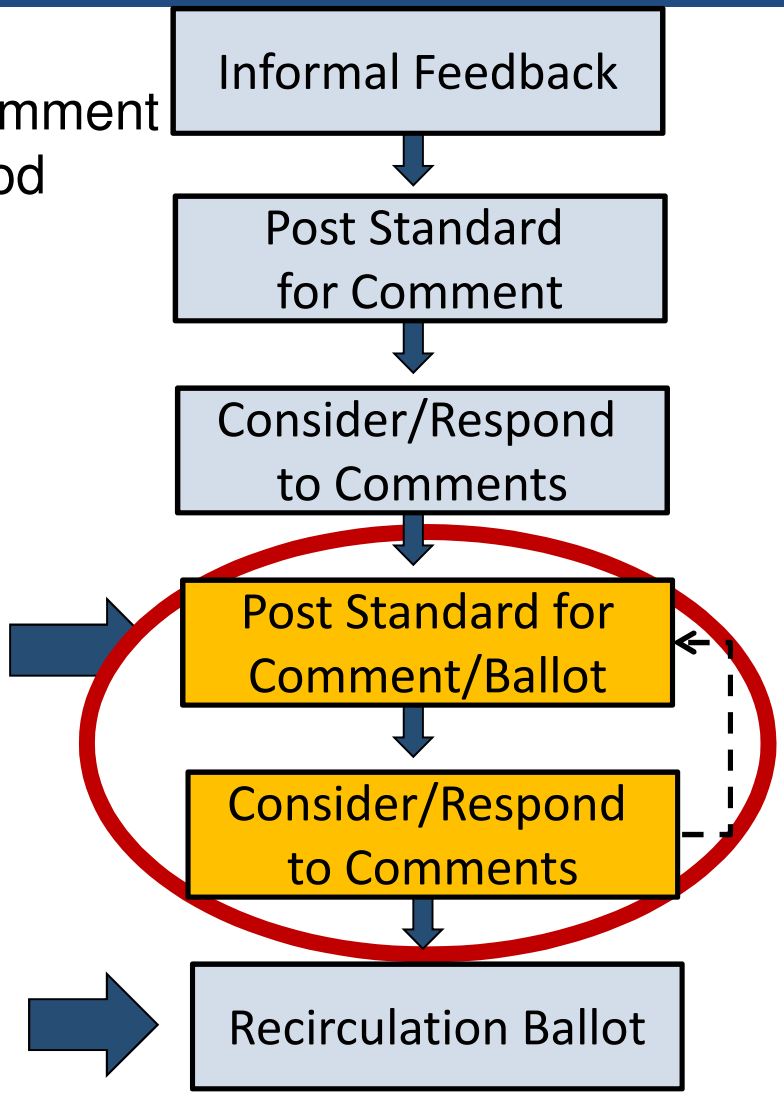


Stakeholder Consensus Process

CIP Version 5 posted for 60-day formal comment and simultaneous 20-day initial ballot period

New/Successive Ballot:
At this step, the standard is either "new" or significantly changed from the last version posted for comment/ ballot. The ballot record starts with no votes and no comments.

Recirculation Ballot:
At this step, there have been no significant changes to the standard from the last ballot. The ballot record starts with all votes and comments from the previous ballot.



CIP Version 5 Posting

- 12 initial ballots
  - Ten standards
  - Definitions
  - Implementation plan
- One ballot body
  - Flexibility going forward
  - Ensures same body balloting related documents (i.e., definitions and related standards)
- One comment form that collectively addresses the topics in all 12 initial ballots

Comment Form Location

Project 2008-06
Cyber Security Order 706 Version 5 CIP Standards

Related Files

Activity: Version 5 CIP Standards (Phase III)

Status: Ten CIP standards (CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 – collectively referred to as the 'Version 5 implementation plan, and the associated definitions are posted for a parallel formal comment period and twelve separate initial bal each for the definitions and implementation pla). In consideration of the volume of documents and the significant changes to the standards, the Standards Committee authorized extending the comment period to 60 days and the initial ballot window to 20 days

Draft	Action	Dates
Draft 1 - Version 5 CIP Standards CIP-002-5 CIP-003-5 (CIP-003-5: REVISED - 11/22/11) CIP-004-5 CIP-005-5 CIP-006-5 CIP-007-5 CIP-008-5 CIP-009-5 CIP-010-1 CIP-011-1 Implementation Plan Definitions **Supporting Materials** Unofficial Comment Form (Word) Mapping Document CIP-002-4	Initial Ballot Vote>>	12/16/11 - 01/06/12
	Formal Comment Period Info>> Submit Comments>>	11/07/11 - 01/06/12

Sample from V5 Comment Form

You do not have to answer all questions. Enter all comments in Simple Text Format.

Questions

1. Many definitions in the Definitions document contain modified definitions from existing terms and new definitions for terms used in these standards. Do you have any suggestions that would improve the proposed definitions? If so, please explain and provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

2. CIP-002-5 Attachment 1 contains criteria that provide the basis for the categorization of BES Cyber Systems and BES Cyber Assets. Most of these criteria are similar to those already approved by the industry as part of Version 4. Do you have any suggestions that would improve the proposed criteria? If so, please explain and provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

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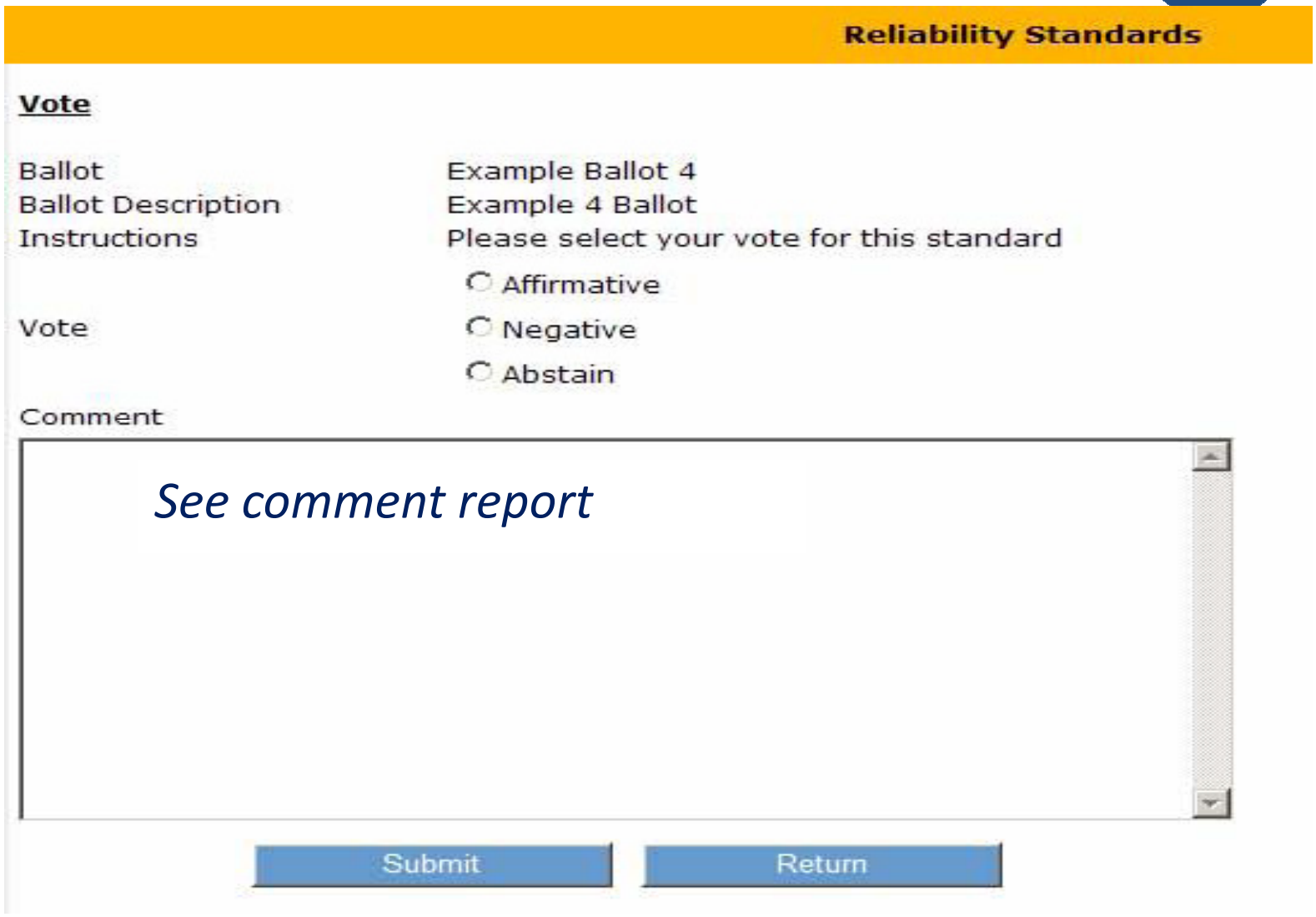
Building Consensus with Comments

- Stakeholder feedback is essential
- The best comments offer suggested replacement language first and then support that suggested language with rationale
- If a stakeholder cannot suggest alternate language, he or she should still make sure to support his or her claim with sound technical rationale

Submitting Comments

- Ballot Comments
  - Add note to ballot “comments submitted”
  - Submit comment through “checkbox form” – not within ballot
  - No need to submit same comment more than once
- Comments on Proposed Standards
  - Submit through electronic form
  - Be brief
  - Provide technical justification if possible/appropriate

Ballot Comments



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Sample Comments

- In attachments one, two, and three the six month requirement for notice is too short in many cases. We suggest nine months to one year. Six months is not enough time for budgeting and construction scheduling.
- The Generator Owner (GO) appears to be the logical choice. The GO has the access to the equipment records, the Generator Operator may not.
- ABC Corporation agrees with the comments submitted by BCD Corporation.

Sample Comments

- Disagree with R2 as written
- Disagree with assigning requirement to the GO
- Definition is a little loose

Version 5 Development Goals

Goal 1: To address the remaining Requirements-related directives from all CIP related FERC orders, all approved interpretations, and CAN topics within applicable existing requirements.	**Goal 5**: To minimize technical feasibility exceptions.
Goal 2: To develop consistent identification criteria of BES Cyber Systems and application of cyber security requirements that are appropriate for the risk presented to the BES.	**Goal 6:** To develop requirements that foster a "culture of security" and due diligence in the industry to complement a "culture of compliance".
Goal 3: To provide guidance and context for each Standard Requirement.	**Goal 7:** To develop a realistic and comprehensible implementation plan for the industry.
Goal 4: To leverage current stakeholder investments used for complying with existing CIP requirements.	

Submit Comments

Project 2008-06
Cyber Security Order 706 Version 5 CIP Standards

Related Files

Activity: Version 5 CIP Standards (Phase III)

Status: Ten CIP standards (CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 – collectively referred to as the 'Version 5 implementation plan, and the associated definitions are posted for a parallel formal comment period and twelve separate initial bal each for the definitions and implementation pla). In consideration of the volume of documents and the significant changes to the standards, the Standards Committee authorized extending the comment period to 60 days and the initial ballot window to 20 days

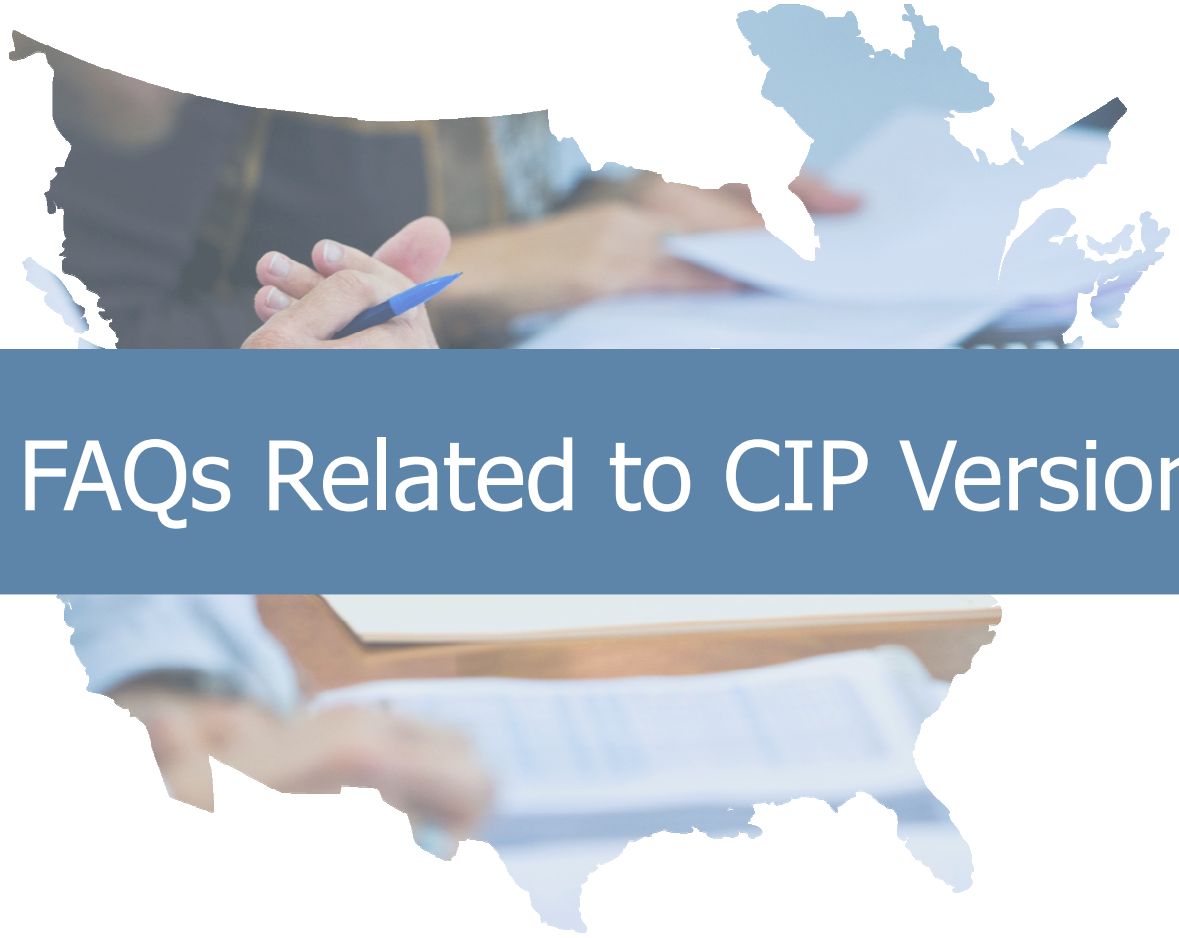
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	Formal Comment Period Info>> Submit Comments>>	11/07/11 - 01/06/12

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Drafting Team Responses to Comments

If Comment:	Then:	And:
Unrelated	Note that comment is unrelated	No action needed
Proposes change beyond scope	Note that comment is proposing an expansion	Add "issues database"
Proposes modification based on new technical issue	Provide team's analysis of the proposal	If accepted, modify standard
Proposed modification based on already vetted technical issue	Provide summary of vetting and resolution	No action needed
Proposes modification to provide greater clarity	Provide team's view as to whether the proposed modification improves clarity	If accepted, modify the standard

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FAQs Related to CIP Version 5 Posting

FAQs to CIP V5 Posting

- Why 12 ballots instead of one?
  - Allows drafting team to gauge relative approval, and allows ballot body to consider each standard on its merits
  - Cloning ballot body provides flexibility
  - Does not impact simultaneous processing
- What if a standard achieves high approval while others do not?
  - Any change to standards/definitions affecting a standard is a substantive change necessitating successive ballot of that standard

FAQs to CIP V5 Posting

- Will separate balloting result in some standards finishing the process before others?
  - V5 development represents a paradigm shift from previous versions and are being developed simultaneously
  - Draft implementation plan specifies that all of the standards and definitions must be approved before they become effective

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Questions?

- Please submit your questions via the ReadyTalk chat window
- Point of Contact – Steven Noess, NERC
  - steven.noess@nerc.net
- Slides and recording of webinar will be posted to the NERC website
- Key Dates:
  - Ballot period begins: December 16, 2011
  - Balloting and comment period ends: January 6, 2012

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Draft CIP Standards Version 5

Technical Webinar – Part 2

Project 2008-06 Cyber Security Order 706 Standards Drafting Team
November 29, 2011

RELIABILITY | ACCOUNTABILITY






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Agenda

- Opening Remarks – John Lim, Consolidated Edison, Chair
- V5 Schedule Update – Philip Huff, AECC, Vice Chair
- V5 Standards Format – Sharon Edwards, Duke Energy
- Definitions – William Winters, Arizona Public Service
- CIP-003-5 through CIP-011-1 – SDT Members
- Q&A – Steven Noess, NERC

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CIP Version 5 Schedule Update

Philip Huff, Arkansas Electric Cooperative Corporation

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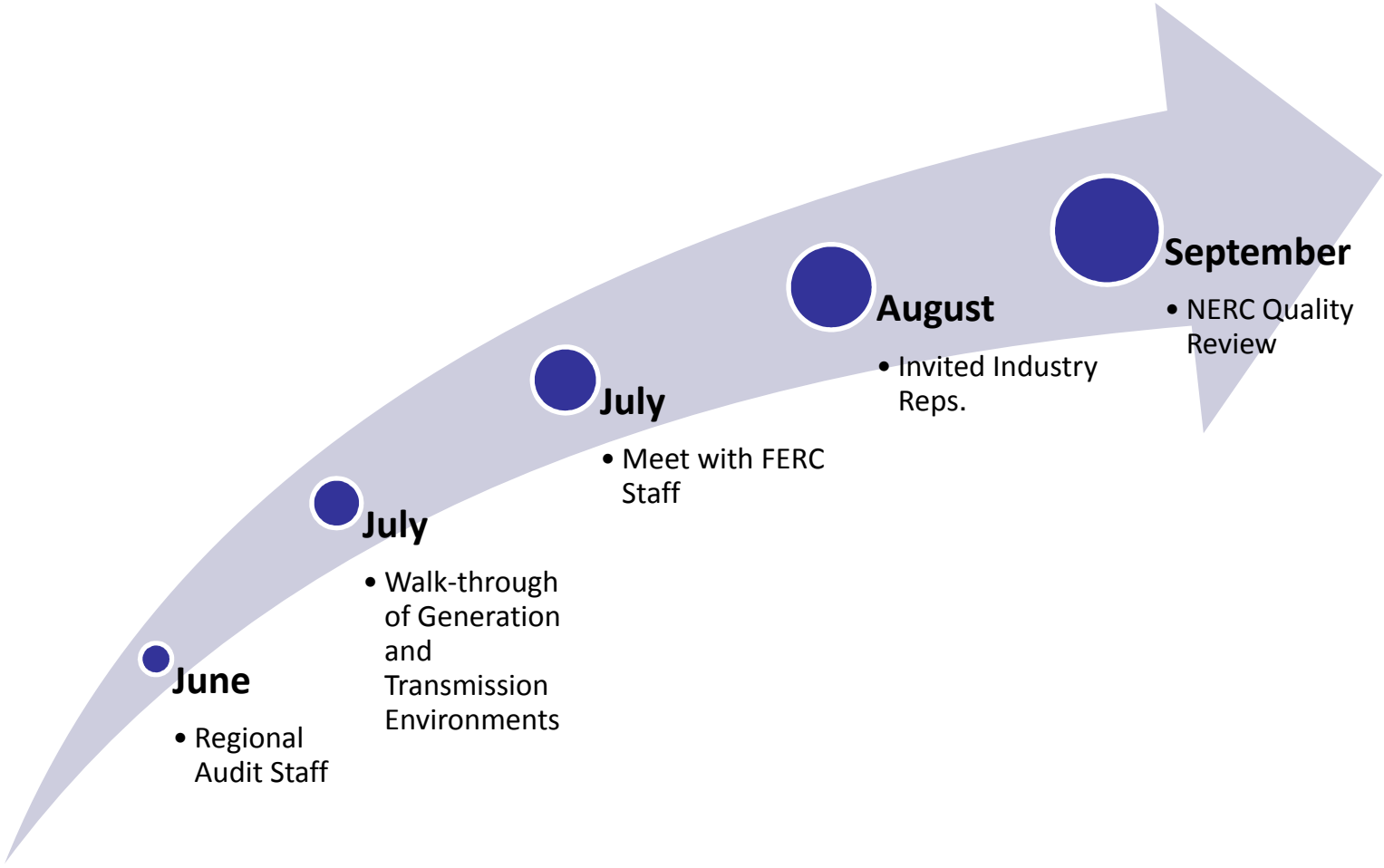



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Development Goals

Goal 1: To address the remaining Requirements-related directives from all CIP related FERC orders, all approved interpretations, and CAN topics within applicable existing requirements.	**Goal 5**: To minimize technical feasibility exceptions.
Goal 2: To develop consistent identification criteria of BES Cyber Systems and application of cyber security requirements that are appropriate for the risk presented to the BES.	**Goal 6:** To develop requirements that foster a "culture of security" and due diligence in the industry to complement a "culture of compliance".
Goal 3: To provide guidance and context for each Standard Requirement.	**Goal 7:** To develop a realistic and comprehensible implementation plan for the industry.
Goal 4: To leverage current stakeholder investments used for complying with existing CIP requirements.	

Development Schedule



Comment and Ballot Period

- November 7, 2011 – January 6, 2012
  - Formal 60-day comment period
- December 16, 2011 – January 6, 2012
  - Initial Ballot

Long Term Schedule 2012

January 6 – March 26	• Consideration of comments
March 26 – April 27	• 30-day posting for comment and successive ballot
June 6–22	• Possible Recirculation ballot

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CIP Version 5 Standards Format

Sharon Edwards, Duke Energy

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Format Components – CIP 005

Rationale for R1: The Electronic Security Perimeter serves to control and monitor traffic at the external boundary of the BES Cyber System. It provides a first layer of defense for network based attacks ….

Summary of Changes: CIP-005 R1 has taken more of a focus on the discrete Electronic Access points rather than the logical "perimeter".

CIP-005 R1.2 has been deleted. This requirement was definitional in nature and used to bring dialup modems using non-routable protocols into the scope of CIP-005. The non-routable protocol exclusion no longer exists, therefore there is no need for this requirement.

CIP-005 R1.1 and 1.3 were also definitional in nature and have been deleted as separate requirements but the concepts were integrated into the definitions of ESP and EAP.

R1. Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable items in *CIP-005-5 Table R1 – Electronic Security Perimeter. [Violation Risk Factor: Medium]*

M1. Evidence must include each of the applicable documented processes that collectively include each of the applicable items in *CIP-005-5 Table R1 – Electronic Security Perimeter* and additional evidence to demonstrate implementation as described in the Measures column of the table.

	CIP-005-5 Table R1 – Electronic Security Perimeter		
Part	**Applicability**	**Requirements**	**Measures**
1.1	Low Impact BES Cyber Systems with External Routable Connectivity	Define technical or procedural controls to restrict unauthorized electronic access.	Evidence may include, but is not limited to, documented technical and procedural controls that exist and have been implemented.
Reference to prior version: *CIP-005 R1*		**Change Rationale:** *Entities are to document perimeter type security controls they have implemented to segment low impact BES Cyber Systems from public or other less trusted network zones and to prevent access to an aggregation of enough low impact BES Cyber Systems at various locations to a degree that can cause higher level impacts to the BES.*	
1.2	High Impact BES Cyber Systems Medium Impact BES Cyber Systems. Associated Physical Access Control Systems Associated Protected Cyber Assets	Control and secure all routable and dial-up connectivity through the use of identified Electronic Access Points (EAPs).	Evidence may include, but is not limited to: • Network diagrams showing EAP identification or • A list of uniquely identifiable Cyber Assets within the BES Cyber System and assoc. EAPs.

- **Rationale for the requirement**
- **Summary of changes from previous version**
- **Main requirement and measure**
- **Requirement rows**
  - **Applicability**

    (low, medium, high)
  - **Sub-requirements**
  - **Measures for sub-requirements**
  - **Reference to prior versions**
  - **Change rationale for sub-requirement**

Format – Rationale and Summary of Changes Sections

Rationale for R1: The Electronic Security Perimeter serves to control and monitor traffic at the external boundary of the BES Cyber System. It provides a first layer of defense for network based attacks as it limits reconnaissance of targets, restricts and prohibits traffic to a specified rule set, and assists in containing any successful attacks.

Summary of Changes: CIP-005 R1 has taken more of a focus on the discrete Electronic Access points rather than the logical "perimeter".

CIP-005 R1.2 has been deleted. This requirement was definitional in nature and used to bring dialup modems using non-routable protocols into the scope of CIP-005. The non-routable protocol exclusion no longer exists, therefore there is no need for this requirement.

CIP-005 R1.1 and 1.3 were also definitional in nature and have been deleted as separate requirements but the concepts were integrated into definitions.

- **Rationale –** Purpose of requirement and any assumptions made about the requirement
- **Summary of Changes –** High level overview of changes in this requirement

Format – Main Requirement and Measure

R1. Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable items in *CIP-005-5 Table R1 – Electronic Security Perimeter*. *[Violation Risk Factor: Medium]*

M1. Evidence must include each of the applicable documented processes that collectively include each of the applicable items in *CIP-005-5 Table R1 – Electronic Security Perimeter* and additional evidence to demonstrate implementation as described in the Measures column of the table.

- **Requirement** specifies what is needed for compliance
- **Measure** explains the type of evidence that must be included to demonstrate compliance
- Most requirements reference a **table** immediately below

Format – Requirement Rows

	CIP-005-5 Table R1 – Electronic Security Perimeter		
Part	**Applicability**	**Requirements**	**Measures**
1.1	Low Impact BES Cyber Systems with External Routable Connectivity	Define technical or procedural controls to restrict unauthorized electronic access.	Evidence may include, but is not limited to, documented technical and procedural controls that exist and have been implemented.
Reference to prior version: *CIP-005 R1*		**Change Rationale:** *Entities are to document perimeter type security controls they have implemented to segment low impact BES Cyber Systems from public or other less trusted network zones and to prevent access to an aggregation of enough low impact BES Cyber Systems at various locations to a degree that can cause higher level impacts to the BES.*	

- **Requirement row specifics – Low Impact - CIP 005**
  - Sub requirement number
  - Applicability – Identifies the groups of assets which must comply with requirement
  - Requirement – Specifies what is needed for compliance with sub requirement
  - Measures – Explains how compliance with sub requirement may be demonstrated
    - Documented and implemented technical or procedural controls
  - Reference to prior to version – Identifies where the requirement was previously found in CIP
  - Change rationale related to the sub requirement

Format – Requirement Rows

	CIP-005-5 Table R1 – Electronic Security Perimeter		
Part	**Applicability**	**Requirements**	**Measures**
1.2	High Impact BES Cyber Systems Medium Impact BES Cyber Systems Associated Physical Access Control Systems Associated Protected Cyber Assets	Control and secure all routable and dial-up connectivity through the use of identified Electronic Access Points (EAPs).	Evidence may include, but is not limited to: • Network diagrams showing EAP identification or • A list of uniquely identifiable Cyber Assets within the BES Cyber System and associated EAPs.
Reference to prior version: *CIP-005 R1*		**Change Rationale:** *Changed to refer to the defined term Electronic Access Point and BES Cyber System*	

- **Requirement row specifics – High and Medium Impact – CIP 005**
  - Sub requirement number
  - Applicability – Identifies the groups of assets which must comply with requirement
  - Requirement – Specifies what is needed for compliance
    - Controls apply to identified Electronic Access Points
  - Measures – Explains how compliance with sub requirement may be demonstrated
  - Reference to prior to version – Identifies where the requirement was previously found in CIP

Format – Applicability

- **All Responsible Entities**
- **BES Cyber System :** One or more BES Cyber Assets that are typically grouped together, logically or physically, to operate one or more BES Reliability Operating Services.
  - High Impact BES Cyber Systems
  - Medium Impact BES Cyber Systems
  - Low Impact BES Cyber Systems
- **Electronic Access Control or Monitoring Systems :** Cyber Assets used in the access control or monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems.
- **Physical Access Control Systems :** Cyber Assets that control, alert, or log access to the Defined Physical Boundary(s), exclusive of locally mounted hardware or devices at the Defined Physical Boundary such as motion sensors, electronic lock control mechanisms, and badge readers.
- **Protected Cyber Asset:** A Cyber Asset connected using a routable protocol within an Electronic Security Perimeter that is not part of the BES Cyber System. A Transient Cyber Asset is not considered a Protected Cyber Asset.

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CIP Version 5 Definitions

William Winters, Arizona Public Service

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Definitions

- Consolidated in a single document, which is referenced in the Definitions section of each standard
- Terms already defined in the Glossary of Terms used in NERC Reliability Standards are not repeated here
- New or revised definitions become approved when the proposed standard is approved
- **When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary**
- New defined terms are underscored
- For existing glossary terms, new language is shown as underscored, while deleted language is shown as stricken

Definitions Retired and Replaced

- Critical assets
  - Replaced by CIP-002 Attachment 1 and BES Reliability Operating Services definition
- Critical cyber assets
  - Replaced by BES Cyber Asset and BES Cyber System
- Physical security perimeter
  - Replaced by Defined Physical Boundary
  - No more “six-wall” specification

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Definitions
18 New, 3 Revised

	CIP002	CIP003	CIP004	CIP005	CIP006	CIP007	CIP008	CIP009	CIP010	CIP011
BES Cyber Asset	x					x			x	x
BES Cyber Security Incident						x	x		x	
BES Cyber System	x	x	x	x	x	x		x		
BES Cyber System Information										x
BES Reliability Operating Services	att 1									
CIP Exceptional Circumstance			x			x			x	
CIP Senior Manager	x	x	x			x			x	
Control Center	att 1									
Cyber Assets				x					x	
Defined Physical Boundary (“DPB”)					x					
Electronic Access Control or Monitoring Systems					x	x			x	
Electronic Access Point (“EAP”)				x		x				
Electronic Security Perimeter (“ESP”)				x						
External Connectivity										
External Routable Connectivity				applicability						
Interactive Remote Access				x						
Intermediate Device				x						
Physical Access Control Systems					x	x				
Protected Cyber Asset				x		x				
Reportable BES Cyber Security Incident							x			
Transient Cyber Asset						x				

Definitions
Core Applicable Assets

- **Cyber Assets** – Programmable electronic devices including the hardware, software, and data in those devices
- **BES Cyber Asset** – A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its operation, mis-operation, or non-operation, when required, adversely impact one or more BES Reliability Operating Services
- **BES Cyber System** – One or more BES Cyber Assets that are typically grouped together, logically or physically, to operate one or more BES Reliability Operating Services
  - Largely replaces Critical Cyber Asset
  - Provides an opportunity for controls to be applied at a system level

Definitions
Related Applicable Assets

- **Electronic Access Control or Monitoring Systems** – Cyber Assets used in the access control or monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems
- **Electronic Access Point** – An interface on a Cyber Asset that restricts routable or dial-up data communications between Cyber Assets
- **Intermediate Device** – A Cyber Asset that 1) may be used to provide the required multi-factor authentication for the interactive remote access; 2) may be a termination point for required encrypted communication; and 3) may restrict the interactive remote access to only authorized users
- **Physical Access Control Systems** – Cyber Assets that control, alert, or log access to the Defined Physical Boundary exclusive of locally mounted hardware or devices at the Defined Physical Boundary such as motion sensors, electronic lock control mechanisms, and badge readers

Definitions
Related Applicable Assets

- **Protected Cyber Asset** – A Cyber Asset connected using a routable protocol within an Electronic Security Perimeter that is not part of the BES Cyber System
- **Transient Cyber Asset** – A Cyber Asset that is; 1) directly connected for 30 calendar days or less to a BES Cyber Asset or Protected Cyber Asset, 2) used for data transfer, maintenance, or troubleshooting purposes, and 3) capable of altering the configuration of or introducing malicious code to the BES Cyber System

Definitions Boundaries

- **Electronic Security Perimeter ("ESP")** – A collection of Electronic Access Points that protect one or more BES Cyber Systems
  - Asset based definition
  - Physical not logical
- **Defined Physical Boundary ("DPB")** – The physical border surrounding locations in which BES Cyber Assets, BES cyber Systems, or Electronic Access Control Systems reside and for which access is controlled
  - Replaces PSP definition
  - Provides for flexibility in physical boundary access controls
  - Not limited to "six-wall" perimeter
  - Does not exclude "six-wall" perimeter

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CIP-003-5: Security Management Controls

David Revill, Georgia Transmission Corporation

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CIP-003-5 Summary of Modifications

- CIP-003-5 was reorganized to only include elements of policy and cyber security program governance
  - Elements that addressed Change Control and Configuration Management were moved to CIP-010-1
  - Elements that addressed Information Protection were moved to CIP-011-1

CIP-003-5 Summary of Modifications

- Leadership – R1
- Policy – R2
  - Removed reference to policy addressing all “requirements”
  - Introduction of 10 topics based on the titles of each of the CIP standards with the addition of Remote Access and CIP Exceptional Circumstances
  - Remote Access policy elements from past CIP-005 Urgent Action process
- Exceptions to Policy
  - Requirement removed
- Policy Approval – R3

CIP-003-5 Summary of Modifications

- Awareness of the Policy – R4
  - Allows additional flexibility from previous requirement to make the policy “readily available”
- Delegation Authority – R5
  - Establishes a framework to clearly address FERC Order 706 and the 2003 Blackout Report
  - Attempt to add clarity to the expectation of the requirement allowing for delegations
  - Explicitly allows for delegation of the delegation authority
  - Delegations may be established by position
- CIP Senior Manager and Delegation Updates – R6
  - Footnote: Delegations remain in effect after a change in the CIP Senior Manager

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CIP-004-5: Summary of Modifications

Jerry Freese, American Electric Power

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CIP-004-5 Summary of Modifications

- Security Awareness – R1
  - Continues with awareness and quarterly reinforcement – Applicable to all responsible (functional) entities but those with authorized access not singled out
- Training – Role-based – R2
  - Identification of roles and specific role-based training
  - Addition of visitor control program
  - Electronic interconnectivity supporting the interoperability of BES Cyber Systems with other cyber assets
  - Storage media as part of the handling of BES Cyber Systems information
- Training Documentation and Implementation – R3
  - Differentiates training provisions to cover both the “program” requirements and “implementation” requirements

CIP-004-5 Summary of Modifications

- Training Documentation and Implementation – R3 Continued
  - Training prior to granting authorized access modified for CIP Exceptional Circumstances
  - Further defines ‘Annual’ as calendar year not to exceed 15 months

CIP-004-5 Summary of Modifications

- Personnel Risk Assessment – R4
  - Identity verification limited to initial PRA only
  - Seven-year criminal history checks add all locations of 6 month or more duration where the subject resided, was employed or attended school
  - Provides for partial criminal history checks with documented reasons for any omissions
  - Includes documenting the processes used to determine when to deny access
  - Differentiates training provisions to cover both the “program” requirements and “implementation” requirements
  - Separates contractors and service vendors into different table (R5)

CIP-004-5 Summary of Modifications

- R5 Verifying Individuals with access to BES Cyber Systems have been assessed for risk (Includes Contractors, Vendors) prior to authorization
  - Primary change – Measure allows vendor attestations verifying PRAs were completed prior to access being authorized
  - Other measure includes dated records verifying that PRAs were completed prior to authorizing access
  - Seven-year update removed the “for cause” renewal

CIP-004-5 Summary of Modifications

- Access Authorization – R6
  - Consolidated authorization and review requirements from CIP-003-4, CIP-004-4, CIP-006-4 and CIP-007-4
  - Enable quarterly and annual reviews to find and fix problems rather than self-report everything as a violation
  - Substitutes “provisioning-to-authorization” comparison for individual account listings on all BES cyber assets
  - List of authorized personnel no longer required
  - The CIP Senior Manager or delegate must authorize electronic and physical access to BES Cyber Systems and access to BES Cyber System Information

CIP-004-5 Summary of Modifications

- Authorization – R6 Continued
  - Quarterly verification that those individuals provisioned for unescorted physical or electronic access are authorized
  - Annual verification that all account groups or role categories and associated privileges are correct and the minimum required
  - Annual verification that access privileges to BES Cyber System Information are correct and the minimum required

CIP-004-5 Summary of Modifications

- Revocation – R7
- Addresses "immediate" access revocation when the need for access no longer exists, job changes, or end of employment (FERC Order 706, Paragraph 460)
  - Resignations/Terminations: revoke concurrent with time of resignation or termination (Physical and Interactive Remote Access)
  - Reassignments/Transfers: End of next calendar day (Electronic and Physical Access)

CIP-004-5 Summary of Modifications

- Access Revocation Continued
  - Revoke Access to BES Cyber System Information (end of next calendar day)
  - Revoke user accounts within 30 days of initial access revocation
  - Transfers, reassignments, resignations, terminations
    - Change passwords for shared accounts within 30 days, or if there are extenuating circumstances, within 10 days of the end of extenuating circumstances

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CIP-005-5: Electronic Security Perimeter(s)

Christine Hasha, Electric Reliability Council of Texas

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CIP-005 Summary of Modifications

- Define ‘External Routable Connectivity’ for scope modification
- Focus on ‘Electronic Access Points’ of the ESP
- Require IDS at Control Centers
- Add clarity to ‘secure’ dialups
- Inclusion of Remote Access requirements

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CIP-006-5: Physical Security

Kevin Sherlin, Sacramento Municipal Utility District

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CIP-006-5 Summary of Modifications

- Physical Security of BES Cyber Systems
  - Defined Physical Boundary replaces Physical Security Perimeter ("six-wall border")
- R1 – One or More Physical Security Plans
  - Low Impact – Operational or procedural controls to restrict physical access
  - Medium Impact – Establish one or more Defined Physical Boundaries with at least one physical access control; issue real-time alerts; log of physical entry
  - High Impact – Establish one or more Defined Physical Boundaries with two or more different and complementary physical access controls; issue real-time alerts; log of physical entry

CIP-006-5 Summary of Modifications

- R1 – One or More Physical Security Plans Continued
  - Physical Access Control System – Issue real-time alerts
- R2 – Visitor Control Program
  - High/Medium Impact – Continuous escorted access within Defined Physical Boundary; log entry/exit on a 24 hour basis to each Defined Physical Boundary
- R3 – Maintenance and Testing
  - Physical Access Control System - Testing changed to a 24 month cycle to include locally mounted devices
  - Physical Access Control System – Log failures and outages

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CIP-007-5: Systems Security Management

Jay Cribb, Southern Company

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CIP-007 Summary of Modifications

- Removal of “Logon Banner” requirement
- Security Event Monitoring failure handling
- Addition of physical I/O port requirement
- Security Patch mgt source requirement
- Non-prescriptive malware requirement
- Bi-weekly log summary/sampling reviews

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CIP-008-5: Incident Reporting and Response Planning

Thomas Stevenson, Constellation Energy

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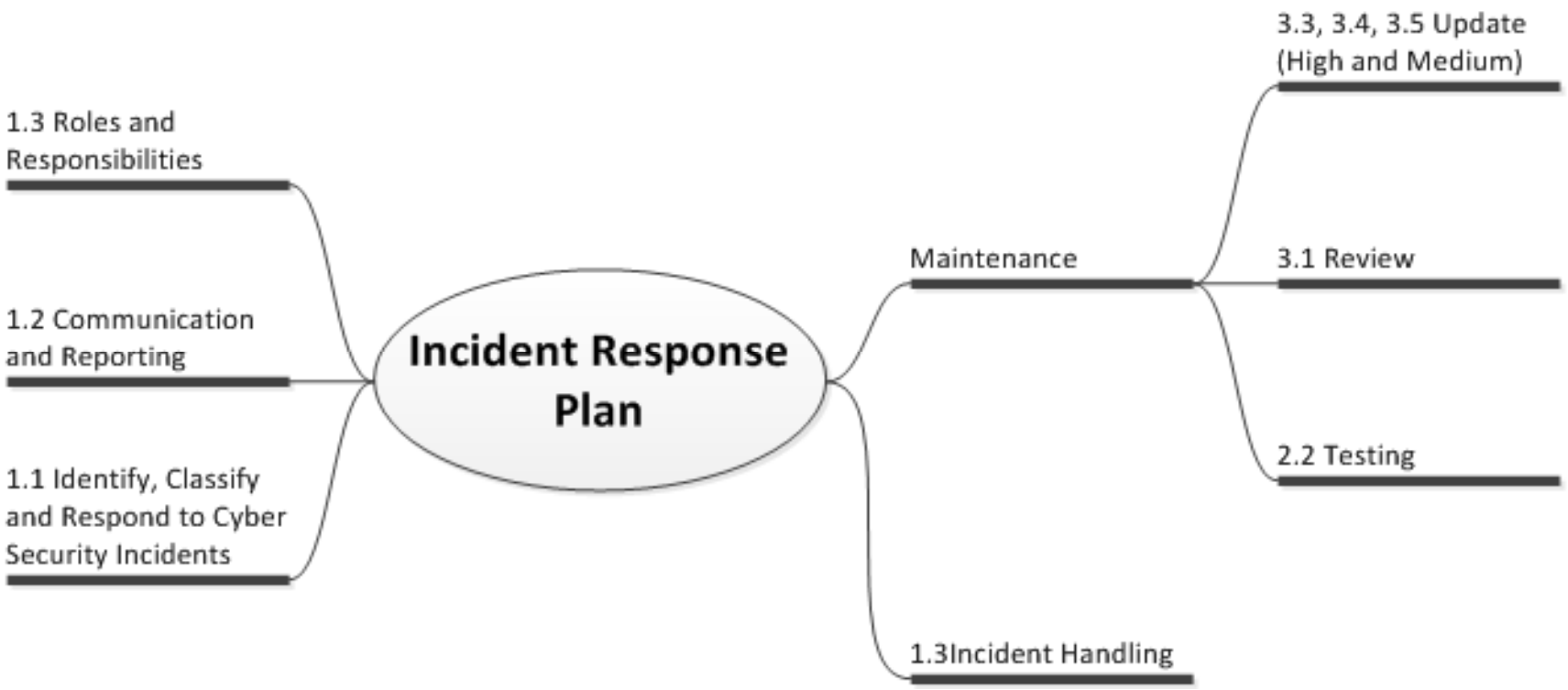

CIP-008-5 Summary of Modifications

- Defined Reportable Cyber Security Incident for clarity
- Harmonized with EOP-004-2 regarding specific reporting requirements
- Included additional specification on update and lessons learned associated with the response plan

Applying to All Responsible Entities

- CIP-008 R1, R2 and 3.1 apply to all Responsible Entities
- Possible to have a single plan – Not per Cyber System
- Rationale
  - Increases the ability of the industry to coordinate a response in a multi-site cyber attack. Every entity has a plan and knows who to contact.
  - High return for minor effort. Not the same degree of maintenance required for preventative controls (i.e. access control, patch management).
  - Key part of a basic security program.

Incident Response Plans



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CIP-009-5: Recovery Plans for BES Cyber Systems

Thomas Stevenson, Constellation Energy

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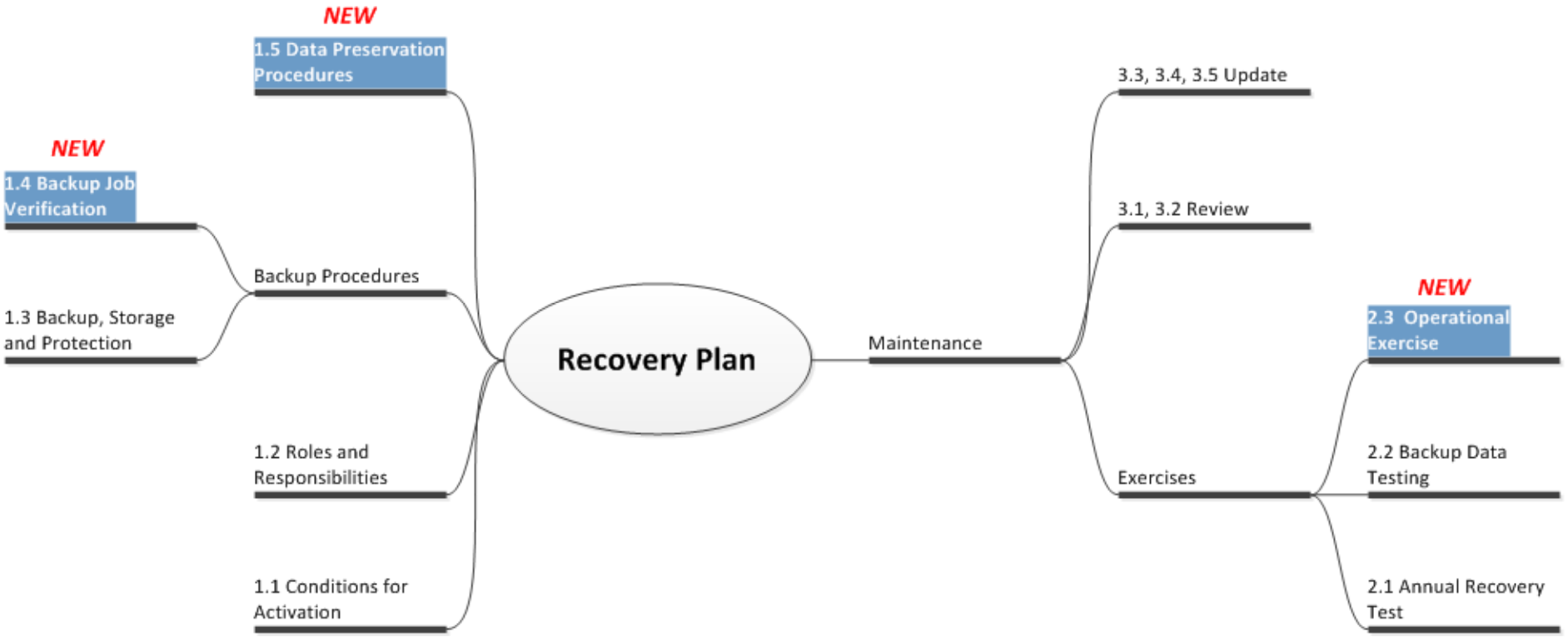





CIP-009-5 Summary of Modifications

- Added requirement to implement the recovery plan
- Verification of backup media information prior to storage
- Preservation of data for analysis
- Requirements Similar to CIP-008 structure
  - (R1) Plan, (R2) Exercise, (R3) Maintain

Recovery Plans



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CIP-010-1: Configuration Change Management

David Revill, Georgia Transmission Corporation

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CIP-010-1 Summary of Modifications

- Configuration Change Management – R1
  - Previously these requirements were dispersed throughout CIP-003-4, CIP-005-4, and CIP-007-4

CIP-010-1 Summary of Modifications

- The SDT proposes the development of a new Standard CIP-010-1 that consolidates all references to Configuration Change Management and Vulnerability Assessments
  - Use of a baseline to add clarity on when the change management process should be invoked
  - Explicit requirement for authorization of changes
  - Tied update of documentation to the change process
  - Clarified testing requirements
    - Testing in a test environment prior to implementation for High Impact BES Cyber Systems
    - Verification of security controls after a change is implemented for High and Medium Impact BES Cyber Systems (and other associated systems)

CIP-010-1 Summary of Modifications

- Configuration Monitoring – R2
  - New requirement for High Impact BES Cyber Systems
  - Responsive to FERC Order 706 ¶ 397 to address potential malicious actions in the change process
- Vulnerability Assessments – R3
  - Paper vs. active vulnerability assessment
    - Additional detail provided in guidance
  - Active vulnerability assessment required every 3 years for High Impact BES Cyber Systems (FERC Order 706 ¶ 541, 542, 544, 547)
  - Mitigation plan now included "planned date of completion" as per FERC Order 706 ¶ 643

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CIP-011-1: Information Protection

David Revill, Georgia Transmission Corporation

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CIP-011-1 Summary of Modifications

- The SDT proposes the development of a new Standard CIP-011-1 that consolidates all references to Information Protection and Media Sanitization
  - Previously these requirements were dispersed throughout CIP-003-4 and CIP-007-4
- The SDT has also moved the requirements regarding the authorization and revocation of access to BES Cyber System Information to CIP-004-5, consolidating these requirements with those for electronic and physical access

CIP-011-1 Summary of Modifications

- Information Protection – R1
  - Requirement for classification removed as there was no requirement to on how to protect different classifications
  - Types of information requiring protection moved to a glossary definition – “BES Cyber System Information”
  - Replaced requirement to “protect” information with a requirement to implement “access control and handling procedures”

CIP-011-1 Summary of Modifications

- Media Reuse and Disposal – R2
  - Very similar to previous requirements
  - Requirements focused on outcome and specific methods removed (which in some cases may not have achieved the desired outcome)
  - Attempted to allow for scenario where equipment must be shipped back to vendor for support
    - BES Cyber System has not yet been disposed of or released for reuse

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Questions?

- Please submit your questions via the ReadyTalk chat window
- Point of Contact: Steven Noess, NERC
  - steven.noess@nerc.net
- Slides and recording of Webinar will be posted to the NERC website
- Key Dates:
  - CIP Version 5 Balloting Update Webinar: December 13, 2011
  - Ballot Period Begins: December 16, 2011
  - Balloting and Comment Period Ends: January 6, 2012

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Comment Form for 6th Draft of Standards for Real-Time Operations (Project 2007-03)

Comments on the 6th draft and successive ballot of the standards for Real-Time Operations (Project 2007-03) must be submitted by **January 12, 2012.** If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information:

In the 6th posting for Project 2007-03, the Real-Time Operations Standard Drafting Team (RTOSDT) has attempted to clarify the proposed changes to the TOP family of standards based on industry comments received for the 5th posting and suggestions made during the Quality Review. Changes made were:

TOP-001-2:

- Changed the title of the standard to 'Transmission Operations' to better reflect the content of the standard.
- Based on Quality Review feedback changed the Purpose of the standard to more fully align with the requirements of the revised standard.
- Revised Requirement R1 to note that a Reliability Directive should be identified as such
- Deleted 'upon recognition' from Requirement R2
- Deleted 'all other' from Requirement R3
- Added Reliability Coordinator to Requirement R5
- Deleted Generator Operator from Requirement R6 and clarified that the requirement was for 'telemetry equipment'
- Deleted the 30 minute limit from Requirement R9 and replaced it with references to Facility Rating and Stability criteria
- Deleted the 30 minute limit from Requirement R11 to correspond with the change in Requirement R9
- Made a semantic change for clarity to Measure M2
- Changed the Time Horizons for Requirements R3, R5, and R8
- VSLs for Requirements R3, R5, and R6 were changed to move away from percentages
- The language for the VSLs in Requirements R2, R6, & R8 was clarified
- Based on Quality Review feedback modified the Data Retention section to reflect the current NERC Rules of Procedure.

TOP-002-3:

- Revised Requirement R2 to read as a positive statement rather than as a double negative
- Added the term "NERC" as a modifier of "registered entities" in Requirement R3
- Changed the VRF for Requirement R3 to Medium
- Modified the VSLs for Requirement R1
- Based on Quality Review feedback modified the Data Retention section to reflect the current NERC Rules of Procedure.

TOP-003-1:

- Based on Quality Review feedback, the Purpose of the standard has been modified to more fully align with the requirements of the revised standard.
- The bullets under Requirement R1, Part 1.1 have been deleted.
- Added new Requirement R2 to separate out the responsibilities of Balancing Authorities from Requirement R1.
- In response to Quality Review feedback, modified the language in Requirements R3 and R4 to clarify which data the Transmission Operator and Balancing Authority are to distribute.
- Made conforming changes to Measures to reflect changes to the Requirements.
- Based on Quality Review feedback, modified the Data Retention section to reflect the current NERC Rules of Procedure and Drafting Team Guidelines for evidence retention.
- Made conforming changes to VSLs to reflect changes to Requirements.

Other changes:

- The definition of Reliability Directive has been modified by Project 2006-06 to read as follows:

  "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts."

You do not have 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. The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes
   ☒ No

Comments: Requirements R1 and R2 should not be separate. Having them broken out in this manner could potentially put entities in double jeopardy when non-compliance occurs. The original language provided for a very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one's inability to provide notice. If each function needs to be separate, then Requirement R4 should be broken down into two requirements. Requirement R4 states that information is being requested, AND is available.

In TOP-001-2 R3 the phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. The Glossary defines Emergency as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning Analysis as "An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)." What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency? The Requirement should state TOP's expected to affected by an anticipated Emergency. Those TOP's known to be affected are part of the group expected to be affected.

Operations Planning occurs in the Day ahead. An actual Emergency does not occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning.

Suggest rewording Requirement R3 to:

> R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis.

Without an expressed time period for the notification in R6, doesn't this create an opportunity for broad interpretations of what is permissible and what's not? It also allows for inconsistent treatment. An auditor's view might be very different from an entity's view. Also, regarding TOP-001-2 R6, which states "Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities." This is a big concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator's to the entities within the affected other Reliability Coordinator's footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to "drill down" and have to notify entities outside of their footprints of the aforementioned planned outages.

Regarding TOP-001, Requirement R8:
The drafting team needs to define the term "internal area reliability" in order to improve the clarity of the standard. Double jeopardy is introduced with TOP-001 R8 and FAC-014 R5.2. Fac-014 R5.2 states "The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area"; while TOP-001 R8 states "Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis."

2. The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes
   ☒ No

Comments: The phrasing of the Requirement R1 does not match the rationale box. Based on the Rationale R1, suggest that the requirement should either state the requirement for a process to conduct an Operational Planning Analysis for the next day, or shall conduct an Operational Planning Analysis for the next day. It seems the team could phrase this as a Risk Based Requirement.

> R1. The Transmission Operator shall CONDUCT an Operational Planning Analysis for the next day's planned operations within its Transmission Operator Area to identify where Facility Ratings or Stability Limits will be exceeded during anticipated normal and Contingency event conditions.

Requirement R2 uses a phrase each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 that implies an SOL exists in the TOP area that was not identified pursuant to FAC-011 R2 and communicated per FAC-014 R5. SOL's that affect a TOP internal area would also affect the RC area. The Drafting Team needs to define the term "internal area reliability" in order to improve the clarity of the standard (see Question 1 comments regarding TOP-001 Requirement R8).

Regarding Requirement R3, would notifying GO's of "their roles" in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888 Firewall?

3. The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes
   ☒ No

Comments: TOP-003 R1 and R2 require data specifications for real-time monitoring. R5 obligates the TO, LSE, and Generator Owners to provide this real-time data. These entities provide a wealth of SCADA data that is utilized in real-time monitoring by TOPs and BAs. It is not clear that a communication error or data quality error for several contiguous time periods or intermittent quality issues would not trigger a violation. This could become an overwhelming compliance issue.

TOP-003 R5 has only a severe VSL. Data providers can provide hundreds if not thousands of points to TOPs. If one RTU goes down is the data provider going to be assessed a severe VSL?

4. The VRF, VSL, and Time Horizons are part of a non-binding poll. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes
   ☐ No
   Comments:

5. If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.

Comments: TOP-001-2 is referencing a NERC definition for “Reliability Directive” which is not in effect today and is listed on the Definitions of Terms Used in Standard Section on page 2. It is stated that the definition of “Reliability Directive” would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for “Reliability Directive” changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an “across the board” usable definition.

This Comment Form states under Background Information:

- The definition of Reliability Directive has been modified by Project 2006-06 to read as follows:

  “A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.”

It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts compliance to COM-002.

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2007-03 Real-Time Transmission Operations | Formal Comment Period Open Through Jan 12, 2012 | Three Successive Ballot Windows Open January 3 – 12, 2012
Date: Wednesday, December 14, 2011 8:53:48 AM

Standards Announcement

Project 2007-03 Real-Time Transmission Operations
Formal Comment Period Open:
December 14, 2011 – January 12, 2012
Three Successive Ballot Windows Open January 3 – 12, 2012

Available Now

The Real-time Operations Standards Drafting Team has made revisions to three standards and their associated implementation plan in response to stakeholder comments and a quality review:

- TOP-001-2 Coordination of Transmission Operations
- TOP-002-3 Operations Planning
- TOP-003-2 Operational Reliability Data

Clean and redline versions of these standards, the associated implementation plan, and the VRFs and VSLs are posted for a formal 30-day comment period through 8 p.m. Eastern on Thursday, January 12, 2012.

Note that TOP-001-2, TOP-002-3, and TOP-3-2 reflect the merging of the following standards into a single standard, making it impractical to post a "redline" of the three proposed standards that shows the changes to the last balloted versions of these standards. The last approved versions of the standards listed below have been posted on the project's web page for easy reference.

- PER-001-0 Operating Personnel Responsibility and Authority
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2a Normal Operations Planning
- TOP-003-1 Planned Outage Coordination
- TOP-004-2 Transmission Operations
- TOP-005-2 Operational Reliability Information
- TOP-006-2 Monitoring System Conditions

- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-1 Response to Transmission Violations

Instructions for Submitting Comments
Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please note that comments submitted with ballots will use the same form, and it is NOT necessary for ballot pool members to submit two separate sets of comments (one during the comment period and a second with a ballot). Comments submitted with ballots are extremely valuable to help the drafting team revise its work. However, in an effort to reduce the burden on stakeholders providing comments, the drafting team requests that all comments (both those submitted with a ballot and those submitted by stakeholders not balloting) be submitted through the electronic form. This will ensure that stakeholders only provide a single set of comments. Further instructions will be provided in the announcement that the ballot window is open.

Next Steps
Three individual successive ballots (one for each standard) will be conducted beginning on Tuesday, January 3, 2012 and ending at 8 p.m. on Thursday, January 12, 2012. The ballot pool formed for the initial ballot of the three standards will be cloned to create three separate ballot pools, and all members of the original ballot pool will automatically be eligible to vote in the three individual ballots.

The standards are being balloted individually to provide stakeholders an opportunity to cast separate ballots for each standard. The individual ballots will provide the drafting team better feedback on which standards require additional development to achieve stakeholder consensus. Stakeholders are encouraged to consider each standard on its own merits and cast individual ballots, rather than casting the same ballot for all three standards, in order to assist the drafting team with evaluating which standards require additional development to achieve consensus.

Background
The Project 2007-03 drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. The team has also made revisions to address outstanding Order 693 directives.

Standards Development Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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From: Eleanor Crouch
To: Eleanor Crouch
Subject: Indusrty Webinar: Request for Data or Inofrmation-Response to Order 754 | January 5, 2012
Date: Wednesday, December 28, 2011 5:23:25 PM

Industry Webinar

Request for Data or Information

(Response to Order 754)

January 05, 2012 | 11:00 a.m. – 1:00 p.m. ET

Click here for: Registration for Thursday, January 5, 2012
Click here for: Order 754 Project Page

Objective

NERC's Request for Data or Information was posted for comment on December 22, 2011 concerning the study of single point of failure on protection systems. This 45-day industry review as permitted by the NERC Rules of Procedure, Section 1600 allows industry stakeholders to provide comments for consideration prior to requesting NERC Board of Trustees approval in March 2012. This webinar will provide valuable background on the events that have led to this Request for Data or Information. Following the short presentation, certain members of the development team will be available to address industry questions. **In recognizing the close proximity to the holiday season, a second webinar will be held on Friday, January 20, 2011, 11:00 a.m.–1:00 p.m. ET for those who are unable to attend on January 5**.

Background

Order 754 is the Final Rule approving the interpretation of Interpretation TPL-002-0a PacifiCorp (Project 2009-14) regarding requirement R1.3.10. In addition to the approval, the Commission expressed a concern about single point of failure of protection systems and issued a directive for further investigation. Refer to the NERC project page for detailed background information about the directive.

Data Request Process

Section 1600 of the *Rules of Procedure for the Electric Reliability Organization* governs the process for issuing a Request for Data or Information to industry.

For more information on the meeting or assistance, please contact **Scott Barfield-McGinnis** (via email) or at (404) 446-9689 or Wendy Kinnard (via email) or at (404) 446-9735.

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Unofficial Comment Form

Order 754 - Request for Data or Information

Please **DO NOT** use this form for submitting comments. Please use the electronic form[1] to submit comments on the data request. The electronic comment form must be completed by **Monday, February 6, 2012, 8:00 p.m. ET**.

If you have questions please contact Scott Barfield-McGinnis at scott.barfield@nerc.net or by telephone at 404-446-9689.

Click here for: Order 754 Project Page[2]

Background Information

This posting is soliciting informal comment in accordance with Section 1600 of the NERC Rules of Procedure.[3] NERC may request data or information that is deemed necessary to meet its obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Federal Energy Regulatory Commission's (FERC) regulations. Section 1602 requires NERC to post the proposed request for data or information or a proposed modification to a previously authorized request for data or information for a forty-five (45) day public comment period.

Order 754 is the Final Rule approving the interpretation of Interpretation TPL-002-0a PacifiCorp (Project 2009-14[4]) regarding requirement R1.3.10. In addition to the approval, the Commission expressed a concern about single point of failure of protection systems and issued a directive for further investigation. From the Order, "…the Commission believes that there is an issue concerning the study of the non-operation of non-redundant primary protection systems; e.g., the study of a single point of failure on protection systems" (P19). In the first part of the directive (P20), the Commission directed FERC staff to meet with NERC and its appropriate subject matter experts to explore this reliability concern, including where it can best be addressed, and identify any additional actions necessary to address the matter. This portion of the directive was satisfied by the October 24-25, 2011 Technical Conference. The second part of the directive (P20) requires NERC to submit an informational filing within six months of the Order (March 15, 2012) explaining whether there is a further system

[1] https://www.nerc.net/nercsurvey/Survey.aspx?s=d86ae2907b884db9af1cac68b0afb6ea
[2] http://www.nerc.com/filez/standards/order_754.html
[3] http://www.nerc.com/page.php?cid=1|8|169
[4] http://www.nerc.com/filez/standards/Project2009-14_Interpretation_TPL-002-0_PacifiCorp.html

protection issue that needs to be addressed and, if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC. The data request will help NERC and the Commission to understand the extent of any reliability gap and guide any efforts to address any such reliability gap, if necessary.

Not all sections require a comment. Enter comments electronically in text only format when cutting and pasting from other documents. Avoid using any special characters other than commas and periods.

1. Please enter specific comments about the method of the data request in the provided text box.

   Comments:

2. Please enter specific comments about the data reporting template of the data request in the provided text box. Note: The posted template is the structure of reporting data and actual reporting may use a different mechanism, such as, this electronic comment form.

   Comments:

3. Please enter specific comments about the reporting schedule of the data request in the provided text box.

   Comments:

4. Please enter any other comments about the data request in the provided text box.

   Comments: Guidance for testing is not consistent and may produce less than meaningful results. There is a lack of necessary detail in the documentation. Clarifying information was provided during the webinar and needs to be included in the request. Other information is still unclear. Examples are: What system should be tested? Current or future system or some future system? Similarly, what year and load level should be considered? This is especially important when calculating consequential loss. If some TPs are basing their information off of an extreme weather forecast (sometimes referred to as a 90/10 forecast) and others are using a reference forecast (sometimes referred to as a 50/50 forecast), very different answers to similar situations could be reported.

What system conditions should be tested – dispatch, transfers, etc.? We suggest something along the lines of the most stressful conditions as determined by the TP.

Regarding Table A (page 8) of the Request for Data or Information, there is the likelihood that certain transmission lines above 100 KV may be identified that will not be owned by TOs or GOs. It is imperative to address how the collection of data from all entities will be accomplished.

When counting circuits in Table A, more clarification should be provided on the handling of distribution transformers, GSUs and the impact of normally open circuit breakers or switches. On the teleconference it was stated that transformers with connections less than 115 kV should not be counted unless they were a GSU. It was also stated that when there is a normally open circuit breaker or any switching device, that configuration creates a separate bus.

When determining remote clearing times, can credit be taken for failure of local blocking schemes, thus allowing high speed remote tripping?

On the teleconference it was stated that transformers with connections less than 115 kV should not be counted as a circuit for purposes of Table A unless they were a GSU. It is unclear how to deal with transformers that serve load and also connect generation on the low voltage winding. Suggest that that these transformers not be considered GSUs unless the total generation is greater than 20 MVA nameplate. Also suggest that dedicated GSUs be ignored if the total generation is greater than 20 MVA nameplate.

What is the process if the TP fails to complete the survey by the deadline?

As stated in the Introduction and Survey Scope, at issue is “to first discover the extent and risk involved with single point of protection failure events.” The reliability risk with respect to this issue is sufficiently addressed in NPCC by the application of current NPCC Criteria, Standards, and Directories. Any power system element that can have a significant adverse impact on the bulk interconnected system is not vulnerable to a single point of protection failure for design criteria contingencies.

The NPCC A-10 Criteria tests identify the Bulk Power System elements that are necessary for the reliable operation of the bulk interconnected system. This assessment (annually performed) gauges the impact on the bulk power system under the scenario of a total failure of the local protection at the station being tested. In effect, this process addresses the issue of adequate assessments for single

point of protection failure that can have a significant adverse impact on the bulk interconnected system. NPCC Directory No. 4 requires that the “bulk power system shall be protected by two fully redundant protection groups, each of which is independently capable of performing the specified protective function for that element.” Therefore any power system element that can have a significant adverse impact on the bulk interconnected system is not vulnerable to a single point of protection failure for design criteria contingencies.

From: Wendy Kinnard
To: Wendy Kinnard
Subject: NERC Announcement: Order 754 - Project Page Updated
Date: Thursday, February 02, 2012 9:33:32 AM

Announcement

Order 754 – Project Page Updated

The questions and answers from the January 5 and 20, 2012 webinars have been posted.

Click here for: Order 754 Project Page

For more information or assistance, please contact Scott Barfield-McGinnis (via email) or at (404) 446-9689 or Wendy Kinnard (via email) or at (404) 446-9735.

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Questions and Answers for the January 5 and 20, 2012 Webinars Order 754 – Data Request The Study of Single Point of Failure

Intent of the Request for Data or Information

Please provide the intent of the study. Is it to look at the impact of slower than normal clearing for bus and close-in faults?

The intent of the Request for Data or Information is to identify whether there is a reliability concern associated with the assessment of single points of failure on Protection Systems. The concern identified in Order No. 754 is not limited to specific fault types; however, the Request for Information or Data is focused on bus faults with delayed clearing to minimize the burden on entities while collecting sufficient data to assess the potential scope of the reliability concern if one does exist. The owner will determine if single points of failures exist in the Protection Systems on buses, lines, transformers, and shunt devices at the substation and how these failure modes impact the clearing times. The simulated bus faults are representative of close-in faults on each connected Element, but the Request for Data or Information does not require close-in bus faults be simulated.

Please describe what will happen after the requested data has been submitted? For example, will NERC be analyzing, creating a report, and recommending corrective actions for the industry?

NERC's Reliability Assessment and Performance Analysis group will evaluate the data to determine the extent to which single point of failure of protection systems may have a negative impact on reliability. The evaluation will aid in determining steps, if any, to improve reliability as well as support an informational filing to FERC in response to Order No. 754.

It seems that the existing TPL standards are sufficient to cause transmission planners to evaluate system reliability without the need for the data requested. What area in the data request is not included in the existing TPL standards?

The existing TPL standards do not establish specific system performance standards for three-phase faults accompanied by a Protection System failure. Single-line-to-ground faults frequently evolve to a multi-phase fault when fault clearing is delayed due to a Protection System failure. This Request for Data or Information will provide data on the extent to which delayed clearing could lead to a significant system disturbance such as those identified in the March 2009 NERC Industry Alert. In cases where delayed fault clearing could result in a similar disturbance, the Request for Data or Information requires reporting of attributes of Protection

Systems and station dc supplies to assist in understanding the extent to which exposure exists to such disturbances.

Is the purpose of collecting transmission line redundancy information to find those areas where delayed clearing exists?

No. Delayed clearing of faults in and of itself does not create a reliability concern. The intent of the study is to identify where delayed clearing results in system performance that could lead to a significant system disturbance such as those identified in the March 2009 NERC Industry Alert. In cases where delayed fault clearing could result in a similar disturbance, the Request for Data or Information requires reporting of attributes of Protection Systems and station dc supplies to assist in understanding the extent to which exposure exists to such disturbances.

Applicability to Entities

To which NERC registrations does this request apply to? Does it only apply to Transmission Planners?

Will Transmission Owners and Generator Owners have to fill out a survey?

This Request for Data or Information identifies the Transmission Planner as the entity responsible for submitting the requested data. Transmission Owners and Generator Owners will not need to submit data directly to NERC. However, Transmission Owners and Generator Owners are expected to provide to their Transmission Planner(s) any information that is necessary for the Transmission Planner to respond to the Request for Data or Information.

Will the Request for Data or Information be sent only to registered Transmission Planners, or also to the Generator Owners and Transmission Owners?

The Request for Data or Information will be sent to Generator Owners and Transmission Owners to make them aware they are expected to provide to their Transmission Planner(s) any information that is necessary for the Transmission Planner to respond to the Request for Data or Information.

Is it necessary to collect generator data? The failure of generator protection is most likely to result in only the loss of the generator, which is already evaluated as Category B or Category C contingencies. Priority should be to collect Transmission Owner data, which will reduce the amount of effort and data to be collected.

The only data that will be collected from Generator Owners is related to generator step-up (GSU) transformers. The majority of data will be collected from Transmission Owners. The Request for Data or Information includes all Facilities connected to buses that meet the criteria in Table A, because a fault on any of the connected Facilities accompanied by a Protection System failure would have the same potential impact on system reliability.

What are the manpower burden and cost implications for Generator Owners? This seems extremely onerous for small generating stations

The burden for Generator Owners will not be significant as the only data the Generator Owner must provide to their Transmission Planner(s) is related to their generator step-up (GSU) transformers. The burden for Generator Owners will be proportional to the number of generators they have connected to buses that meet the criteria in Table A.

What specifically you are expecting from Generation Owners other than providing information to the Transmission Planners on the generator step-up (GSU) transformer protection?

Providing information to the Transmission Planners on the generator step-up (GSU) transformer protection is the extent of the expectation for Generator Owners.

Is the Protection Engineering Group defined as part of the Transmission Owner/Generator Owner or could it also be considered part of the Transmission Planner?

Whether a protection engineering group is part of a Transmission Owner, Generator Owner, or Transmission Planner will depend on the functions for which each entity is registered. Per the NERC Functional Model the Transmission Owner or Generator Owner has responsibility for Protection Systems associated with their Facilities and as part of this Request for Data or Information they are responsible for submitting data to their Transmission Planner. This reporting is required regardless of whether the Transmission Owner or Generator Owner is part of the same company as the Transmission Planner.

Applicability to the Bulk Electric System (BES)

Please confirm whether the Request for Data or Information is limited to the BES

The Request for Data or Information requests information for all Facilities operated at 100 kV or higher that meet the criteria in Table A, regardless of whether the bus would be considered part of the Bulk Electric System under the existing NERC glossary definition.

Presently, in the NPCC footprint the BES is considered to be limited to only the NPCC Bulk Power System (BPS), as defined by the A-10 test. Would this request for information be limited to the BPS buses for entities in NPCC?

The Request for Data or Information is independent of how any region presently defines the Bulk Electric System. If a bus meets the criteria in Table A, the Transmission Planner should include the bus per the method in the Request for Data or Information regardless of whether it meets the regional definition of a Bulk Electric System Element.

What if there is a 115 kV bus that meets the criteria in Table A that is not part of the BES?

If a 115 kV bus meets the criteria in Table A, the Transmission Planner should include the bus per the method in the Request for Data or Information regardless of whether it is considered to be part of the BES.

Responsibilities of Applicable Entities

Will the Request for Data or Information be sent to Canadian registered entities? Page 1 of the overview document states "The purpose of this survey is to solicit data and information from each Transmission Planner in the United States to . . ."

The data request will be sent to all registered entities in the United States and Canada. The overview in the final Request for Data or Information will be corrected.

Will this responding to this data request be mandatory?

Responding to the data request is mandatory for registered entities in the United States. It is not mandatory for registered entities in Canada, but Canadian entities are strongly encouraged to submit data so that decisions regarding this concern are based on complete data across North America.

Should Generator Owners and Transmission Owners wait until contacted by their Transmission Planner to take action?

The first step in the method defined in the Request for Data or Information is based on the Transmission Planner meeting with the Generator Owners and Transmission Owners in its transmission planning area. However, Generator Owners and Transmission Owners are not prohibited from beginning to collect the information described in the Request for Data or Information prior to being contacted by their Transmission Planner.

Are entities expected to review Protection System schematics and wiring diagrams to identify all possible single points of failure?

No, entities are expected to only review Protection System schematics and wiring diagrams for Facilities identified by the Transmission Planner in step 7. For the purposes of the Request for Data or Information it is not necessary to identify every single point of failure. Entities only need to review these diagrams to identify whether a single point of failure exists for each of the attributes in Table B. If a single point of failure is identified, further review is not required for that Element.

Definition of Single Point of Failure

Please define the term "single point of failure"

In general terms a single point of failure exists when failure of a single component can affect the operation of all protection systems applied on an Element(s). For the purposes of this Request for Data or Information, single point of failure would be reported whenever a protection system component does not meet one of the attributes defined in Table B.

Will the Request for Data or Information include single points of failure due to geomagnetic disturbance or other high impact, low frequency events?

No, this Request for Data or Information does not address single point of failure associated with geomagnetic disturbances or other high impact-low frequency (HILF) events.

Will the Request for Data or Information include single points of failure during maintenance periods which can be 2-3 days?

No, this Request for Data or Information only addresses conditions with Protection Systems in their normal operating state. It is recognized that single points of failure may exist during maintenance and testing that do not occur during day-to-day operation, but these single points of failure are not the subject of this Request for Data or Information.

We suspect that many single points of failure will include station batteries, VT's, and CT's. Is this what you are also expecting to find?

The intent of the Request for Data or Information is to identify whether there is a reliability concern associated with the assessment of single points of failure on Protection Systems. The data collected will enable NERC to assess whether there is a reliability concern and if so, whether it is related to specific Protection System components. The data collection for station dc supplies, voltage transformers, and current transformers is designed to avoid skewing the data. For example, the request for voltage transformers and current transformers excludes common primary windings and the request for station dc supply requests additional information regarding alarming when only one station battery is used.

Simulations/Relation to Reliability Standards

What type of studies is the Transmission Planner required to perform – power flow, transient stability?

The method defined in the Request for Data or Information requires a transient stability simulation to identify the system performance for a three-phase fault. An explicit reference will be added to the final Request for Data or Information.

Don't the simulations defined in the data request align with an "extreme event" per TPL-001-2 which is not a design requirement? Why wouldn't non-performance be expected when the system is evaluated beyond design criteria?

It is correct that contingencies to be simulated for this Request for Data or Information would be classified as Category D contingencies in the existing Transmission Planning studies defined in TPL-004-0 and as extreme events in the new TPL-001-2 that has been filed with FERC. The simulated system performance under TPL-004-0 and TPL-001-2 would not be required to meet specific performance requirements. For this reason it is possible that simulated performance will not meet the requirements in Table C. The purpose of this assessment is to identify the extent to which such contingencies could result in system performance that could lead to a significant system disturbance such as those identified in the March 2009 NERC Industry Alert, and where the potential does exist for such system performance, the extent to which Protection Systems are designed to mitigate exposure to such system performance. This information will be used to assess whether there is a reliability concern associated with the assessment of single points of failure on Protection Systems.

The performance requirements for this data request appear more stringent than the NERC Reliability Standards, which require performance for a single-phase fault with delayed clearing. If a bus fault doesn't meet the three-phase fault test, will it be repeated for a single-phase fault to see if it meets the NERC TPL Standards?

No. This Request for Data or Information will not request any information associated with whether an entity complies with exist8ing NERC Reliability Standards. The requested data will be used to identify where delayed clearing results in system performance that could lead to a significant system disturbance such as those identified in the March 2009 NERC Industry Alert. In cases where delayed fault clearing could result in a similar disturbance, the Request for Data or Information requires reporting of attributes of Protection Systems and station dc supplies to assist in understanding the extent to which exposure exists to such disturbances. This data will aid in determining steps, if any, to improve reliability as well as support an informational filing to FERC in response to Order No. 754.

TPL-001-2 does not consider failure of a Protection System anymore; it considers failure of a non-redundant relay in P5. This appears to indicate that failure of a protection system is beyond the design criteria.

The new TPL-001-2 that has been filed with FERC requires consideration of a failure of specified protective relays and tripping relays under contingency P5. It is correct that the scope of this Request for Data or Information exceeds the criteria proposed in TPL-001-2. The purpose of this assessment is to identify the extent to which contingencies could result in system performance that could lead to a significant system disturbance such as those identified in the March 2009 NERC Industry Alert, and where the potential does exist for such system performance, the extent to which Protection Systems are designed to mitigate exposure to such system performance. This information will be used to assess whether there is a reliability concern associated with the assessment of single points of failure on Protection Systems.

Has the NPCC A-10 BPS Criteria document been used as a reference in developing the testing method? Can entities use existing A-10 tests already performed within NPCC in fulfilling this request?

The NPCC A-10 document was not used as a reference in developing the testing method, but there are similarities between the method defined in the Request for Data or Information and the NPCC A-10 criteria document. Registered entities in NPCC will need to compare the method and results of their analyses performed in accordance with the NPCC criteria and determine the extent to which these simulations can be used to fulfill the requirements of this Request for Data or Information.

In the NPCC region, there is a Directory that discusses system protection design criteria. However, these criteria apply only to what NPCC defined as its Bulk Power System. Are you familiar with the Directory (i.e., Directory 4) and does this document addresses certain components of the request?

We are familiar with the criteria in NPCC Directory 4 and there are many similarities between the Protection System attributes defined in Table B of the Request for Data or Information and Directory 4. There also are differences such as Table B does not require consideration of physical separation of Protection System components. Registered entities in NPCC will need to compare their as-built Protection System designs against the attributes in Table B.

Will guidance be provided to specify which seasonal model(s) would be used for the simulations in steps 2 and 6 of the method? Would analysis of only the horizon year summer peak planning model be adequate for this screening?

Additional guidance regarding the study-year and season to be modeled will be provided in the final version of the Request for Data or Information.

In the case where the Protection System owner has a lot of transmission projects underway, should the system assessment be performed "as-is" or how it will be by the end of the reporting period. Otherwise it will present a moving target.

The Protection System information that Transmission Owners and Generator Owners submit to the Transmission Planner should be consistent with the year and season modeled by the Transmission Planner. Additional guidance regarding the study-year and season to be modeled will be provided in the final version of the Request for Data or Information.

Will a single point of failure be considered as a Category B contingency?

No. FERC Order No. 754 approved the interpretation of TPL-002-0 that states single points of failure in Protection Systems are not considered under Category B.

Method

Is the general concept to test ONLY buses in Table A and evaluate Table B based on the buses that meet Table A?

Attempting to summarize in one sentence the method defined in the Request for Data or Information neglects many important steps. It is important that entities follow the detailed method so all data submitted by the Transmission Planners will be on a common basis.

Rather than perform numerous studies, would it not be easier and faster to determine where redundant protection systems are lacking?

The Request for Data or Information has been designed to minimize the overall effort by registered entities and burden on the industry. While identifying where redundant Protection Systems exist would minimize effort for Transmission Planners, using an iterative approach minimizes the overall effort by both the Transmission Planners and the Transmission Owners and Generator Owners and introduces a performance assessment.

In the interest of minimizing impact to Transmission Owners and Generator Owners at the outset of the evaluation process, why is step 1 needed? What percentage of buses do you expect to exclude in this step? Would it not be simpler to test all buses that meet Table A and then examine exclusions using Table B on the list of buses that fail the criteria? Seems it would further reduce entity burden.

While this approach would minimize burden on Transmission Owners and Generator Owners, the method was developed with stakeholder input from the affected groups of entities to minimize the overall burden on industry. Step 1 is intended to take advantage of the Transmission Owner's and Generator Owner's at-hand knowledge about the Protections Systems and should minimize the number of buses to be tested by the Transmission Planner without significant burden on the Transmission Owners and Generator Owners. The number of buses that may be excluded in step 1 will vary depending on existing design practices, but may be significant in some areas.

Step 1 of the evaluation method excludes buses to be tested if the Protection System meets the attributes in Table B. However the wording in Step 2 requires the Transmission Planner to study those busses identified in Step 1 "based on the Owner confirming that the protective system meets the attributes in Table B." These two steps appear to be contradictory.

The intent of step 1 is to create a list of buses to be tested starting from a list of all buses that meet the criteria in Table A, and removing from the list any buses for which Protection Systems on all connected Facilities meet the attributes for all categories in Table B, "Protection System Attributes to be Evaluated," based on the Transmission Owner's or Generator Owner's "as-built" knowledge of the Protection System(s). This intent is not reflected in the posted draft of the Request for Data or Information, leading to the identified contradiction. Steps 1 and 2 of the process will be revised in the final Request for Data or Information to rectify this contradiction.

Step 1 of the evaluation method calls for identifying transformers with through-fault protection. Please confirm whether a transmission transformer differential protection that trips remote terminals via direct transfer trip (DTT) is considered to provide through-fault protection.

Through-fault protection is applied to protect a transformer from the effects of through-fault current for a fault external to the transformer. Since the DTT in this case would operate for faults internal to the transformer differential zone, this would not be considered through-fault protection.

Step 2 and step 6 of the evaluation method requires simulation of a three-phase bus fault. What about end-of-line faults for which remote backup may not operate? For generator step-up (GSU) transformers, is the fault location of concern limited to an external fault on the high-voltage side or does it include internal transformer faults?

For the purpose of this Request for Data or Information it is not necessary to consider end-of-line faults. The intent of the Request for Data or Information is to identify whether there is a reliability concern associated with the assessment of single points of failure on Protection Systems. The concern identified in Order No. 754 is not limited to specific fault types; however, the Request for Information or Data is focused on close-in faults with delayed clearing to minimize the burden on entities while collecting sufficient data to assess the potential scope of the reliability concern if one does exist.

This Request for Data or Information only requires simulation of bus faults as described in the method, which address faults on the terminals of equipment (e.g., the high-voltage side of a generator step-up (GSU) transformer). Internal transformer faults are not considered as part of this Request for Data or Information to minimize the burden on entities while collecting sufficient data to assess the potential scope of the reliability concern if one does exist.

Is it possible to clarify how to treat, for example, a breaker-and-a-half bus within the testing method? Please confirm that the assumption in step 2 should be that no local breakers would operate?

In the testing method the Transmission Planner would model fault clearing based on no local breakers operating. The Transmission Owner or Generator Owner would determine how single points of failure on the protection systems applied on the breaker–and-a-half configuration would impact remote clearing times. Additional explanation will be added to the final Request for Data or Information.

In step 2 and step 6, if the Protection System design includes fully redundant protection schemes but the breakers only have a single trip coil with a breaker failure scheme, is it necessary for the Transmission Planner to simulate tripping remote terminals of all lines, or can tripping be limited to only those lines associated with the breaker failure scheme operation? Can local breaker failure be considered during the testing, since battery failure is excluded?

The simulation specified in the Request for Data or Information was developed to be independent of the Protection System design and intended to consider tripping of all connected

circuits at the remote terminals. This method has been developed to minimize the burden on entities while collecting sufficient data to assess the potential scope of the reliability concern if one does exist. Simulation of remote clearing would be necessary when a single point of failure would prevent both breaker tripping and initiation of breaker failure protection. However, this question raises for consideration whether breaker failure protection should be considered when the only single point of failure of the Protection Systems connected to a given bus are the breaker trip coils. In this case consideration could be given to modifying the method to allow the Transmission Planner to assess performance based on the actual protection system operation or the tripping as performed by the breaker failure scheme. Entities who believe breaker failure protection should be considered in the evaluation method may submit comments on this subject during the 45-day comment period that ends on February 6, 2012.

In step 2 and step 6 when considering transformer protection, is it correct to assume that transformer fault clearing should be simulated based on how the transformer protection would respond for the simulated three-phase bus fault? Specifically if the bus fault is in the transformer differential zone should the transformer differential protection be assumed to provide through-fault protection for the simulated bus fault?

No, for the purposes of this Request for Data or Information the transformer differential should not be considered to provide through-fault protection. The bus fault defined in the testing method has been selected to minimize the burden on Transmission Planners and is representative of a close-in fault on any Element connected to the bus. While the transformer differential would operate for the bus fault, it would not operate for close-in faults on the other Facilities connected to the bus. This point will be clarified in the final Request for Data or Information.

If the Request for Data or Information excludes transformers with only one winding operated at 100 kV or higher (a two-winding step-down transformer for example), how does the evaluation method consider a fault in the transformer protection zone that is not detected by the bus protection. A specific example would be dual bus protection schemes and a single transformer protection scheme with the overlap point at the bus – supplies to such a transformer could be in the transformer zone but the impact on the system would be no different than a fault in the bus zone.

The Request for Data or Information excludes transformers with only one winding operated at 100 kV or higher, that are not generator step-up (GSU) transformers, only for the purpose of identifying buses that meet the criteria in Table A. These transformers are to be included in the data provided regarding Protection Systems that meet the attributes in Table B if they are connected to a bus identified by the Transmission Planner in step 7. The bus fault defined in the testing method has been selected to minimize the burden on Transmission Planners and is representative of a close-in fault on any Element connected to the bus. While the transformer differential would operate for the bus fault, it would not operate for close-in faults on the other Facilities connected to the bus and it would be considered to not operate in the simulation. This point will be clarified in the final Request for Data or Information.

Would bus protection redundancy only be an issue if the bus truly is a straight bus or breaker-and-a-half bus?

Failure of bus protection would result in remote clearing of Elements for any physical configuration in which bus protection is applied (e.g., straight bus, breaker-and-a-half, and double-bus-double-breaker). For the purpose of providing data for the "Buses" tab in the reporting template, information on bus protection attributes would not be relevant for bus configurations in which bus protection is not applied, as may be the case for a ring bus depending on design practices.

Table A

When Table A refers to circuits, e.g., the second row refers to "Buses operated at 100 kV to 200 kV with 6 or more circuits," does circuits mean transmission lines or elements?

As described in the note below Table A, circuits include transmission lines, transmission transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher, and generator step-up transformers.

Would a substation with three circuits connected at 345 kV and five circuits connected at 115 kV meet the criteria in Table A?

The substation described would not require testing of the 345 kV bus. Testing of the 115 kV bus would be required only if a fault on the bus will result in 300 MW or more of consequential load loss as a result of remote clearing.

A 100kV line could be a radial line. Is this counted as a circuit?

Under the present draft of the Request for Data or Information a radial line at any voltage 100 kV or higher would be counted as a circuit for the purpose of identifying buses that meet the criteria in Table A. Entities who believe radial lines should be excluded may submit comments on this subject during the 45-day comment period that ends on February 6, 2012.

When counting circuits for Table A, are transformers counted as circuits. When looking at a 115 kV bus, if there are four lines and two distribution transformers connected, does that meet the threshold of Table A?

For the purposes of identifying buses that meet the criteria in Table A, transformers are counted as circuits only if the transformer is (i) a transformer with the primary terminal and at least one secondary terminal operated at 100 kV or higher, or (ii) a generator step-up (GSU) transformer. A bus with four 115 kV transmission lines and two distribution transformers that step down to a voltage level below 100 kV would have four circuits connected. This example would meet the criteria in Table A only if a fault on the bus will result in 300 MW or more of consequential load loss as a result of remote clearing.

For a substation with an autotransformer, would Table A apply for each voltage level?

The reporting template applies for each voltage level at a substation that meets the testing requirements in Table A. For example, testing would be required at 500 kV and 230 kV for a substation with three 500 kV transmission lines, three 230 kV transmission lines, and a 500/230 kV autotransformer, because both the 500 kV and 230 kV buses would have four circuits connected as defined in Table A.

If a transformer has both sides connected at 100 kV or higher, when counting the 'number of circuits' is the transformer counted at both the high and low voltage 'buses' or just the high-side bus? For example, on slide 18, does transformer T1 count as a 'circuit' for both the 345 kV and the 138 kV bus?

A transformer connected to two buses at 100 kV or higher would be counted for determining whether each of the buses meet the criteria in Table A; i.e., the transformer would count as a circuit for the high-voltage bus and also would count as a circuit for the low-voltage bus. For example, Transformer T1 on slide 18 would be considered a circuit connected to the 345 kV bus and also as a circuit connected to the 138 kV bus.

Would the 115/25 kV distribution transformer in the ring bus example on slide 17 NOT be counted as a circuit connected to the 115 kV bus, thereby resulting in five applicable circuits, and thereby excluding the 115 kV bus?

The 115/25 kV transformer would NOT be counted as a circuit for the purpose of determining whether the 115 kV bus meets the criteria in Table A. However, the bus would be included as meeting the criteria since there are six circuits connected to the bus: five transmission lines and one 230/115 kV transformer.

In slide 17 is T3 counted as a circuit in applying Table A? Is it a 'step-down' transformer?

Transformer T3 on slide 17 is a step-down transformer supplying a customer's facilities and would not be counted as a circuit for the purpose of determining whether the 115 kV bus meets the criteria in Table A.

Is there a minimum size GSU to be counted as a circuit?

No, a minimum MVA threshold has not been established for identifying whether a generator step-up (GSU) transformer is to be counted as a circuit for the purposes of identifying buses that meet the criteria in Table A. Entities who believe an MVA threshold should be established may submit comments on this subject during the 45-day comment period that ends on February 6, 2012.

Do capacitor banks and reactors fall under the term "circuits" for Table A?

Capacitor banks and reactors are not considered to be circuits for the purposes of applying Table A. However, Protection System attributes are to be reported for buses that meet the criteria in Table A that are identified by the Transmission Planner in step 7.

It would be a good idea to give some example figures showing how to count up elements and determine whether a station is required to be analyzed or not.

Example figures will be added as an appendix to the Request for Data or Information to provide additional clarity.

Table B

How should entities consider single points of failure that may affect two or more systems of protection resulting from insufficient separation; e.g., redundant relays on a common rack, redundant control circuits in a common cable tray, conduit, duct bank, or redundant control circuits in a common multi-conductor cable?

For the purposes of the Request for Data or Information it is not necessary to consider physical separation of protection system components such as protective relays or dc control circuitry.

How should entities consider single points of failure if a line is protected by two relays, but the relays are identical? To be considered two independent protective relays must the relays be from two different manufacturers? Does the NERC Request for Data or Information consider this a single point of failure?

For the purposes of the Request for Data or Information it is not necessary to consider whether two protective relays associated with an Element are identical, or whether they have the same manufacturer or algorithm for fault detection.

Are two breaker trip coils required for independence?

Yes, for the purposes of this Request for Data or Information the dc control circuitry must include two trip coils to meet the Protection System attributes in Table B. However, depending on the failures mode and resulting trip times, two trip coils may not be necessary to meet performance requirements.

What about the failure of the communication box into which primary and redundant/backup protection systems terminate?

This would be considered a single point of failure for determining whether the Protection System meets the attributes for communication systems in Table B if communication between protective relays is needed to satisfy BES performance required in the existing Transmission Planning standards.

Table C

For the evaluation, what is meant by "could result in a potential reliability risk?" Does this mean cascading outages, voltage collapse, transient instability, violation of established SOL/IROLs, other?

For the purpose of this Request for Data or Information, a potential reliability risk would exist when the simulated system performance does not meet the performance measures in Table C.

Is the intent of these simulations to identify only system instability due to a potential single point of failure in the Protection System? The Request for Data or Information does not mention reliability concerns such as overload or low voltages? It appears that stability, not steady state, is applicable to this approach, correct?

The performance requirements for this Request for Data or Information were developed based on avoiding significant system disturbance such as those identified in the March 2009 NERC Industry Alert. Evaluation of thermal loading and voltage performance is not required. Transient stability analysis will be necessary to assess whether simulated system performance violates the requirements in Table C.

Are load shedding schemes allowed to maintain stability?

The draft Request for Data or Information does not prohibit modeling existing load shedding schemes that may operate in response to the simulated three-phase fault conditions. Entities may submit comments on this subject during the 45-day comment period that ends on February 6, 2012.

Regarding item 2 bullet 4 and Table C, how can these performance measures be exceeded? The "or more" language is confusing in items 2 and 3. Would it be better to state in item 2, bullet 5 that the results do not meet at least one of the performance measures?

Yes. This recommendation will be incorporated in the final version of the Request for Data or Information.

Why was 1000 MW of generation chosen as a criterion in Table C, especially if the system remains stable? Our largest power plant is greater than 1000MW, which is already covered under a NERC B

The 1000 MW threshold is based on Event Category 3 in the Phase 2 Field Test draft Electric Reliability Organization Event Analysis Process. Tripping a generator for a Category B single-line-to-ground fault is a less severe condition than loss of 2000 MW of generation in the Eastern or Western interconnection or 1000 MW of generation in the ERCOT or Québec interconnection resulting from a three-phase fault accompanied by a Protection System failure.

Could you provide a conceptual example of how one would identify the second performance measure in Table C which refers to island formation of 1,000 MW or higher.

Formation of an island in a stability simulation may be identified, for example, by monitoring the apparent impedance on transmission lines to identify whether lines may trip as the result of a power swing. When this occurs the contingency may be re-simulated with the line tripping and an assessment made of resulting islands. Transient stability programs include screening tools for such analyses. The Request for Data or Information does not specify how the Transmission Planners are to perform this assessment to allow them to utilize the techniques they find most useful.

Table D

Please define specifically what Table D means when referencing 'two independent station dc supplies.' If one has one charger, one set of batteries, with separate dc panels feeding the independent relay systems and trip coils, is that considered 'independent' dc supplies? This directly effects how Table B 'DC Control Circuitry" is used in selecting buses to be evaluated.

The station dc supply consists of a charger and battery, or other dc source that is used for powering the Protection Systems and used for tripping; it does not include the dc distribution panels. In the example provided, the one charger and one set of batteries would be a single dc source. For the purpose of the Request for Data or Information, the separate dc panels feeding the independent relay systems are part of the dc control circuitry. When applying Table B to determine whether a Protection System meets the attributes for independent dc control circuitry it is not necessary to consider the station dc supply. If in the example provided the dc control circuitry, auxiliary relays, and trip coils are independent, the dc control circuitry would meet the attributes in Table B regardless of the station dc supply. Considerations for the station dc supply are in a separate table to avoid influencing the buses to be evaluated. Additional clarification will be added to the Request for Data or Information.

What is the purpose of the dc supply attribute reporting? These attributes are not included in any of the simulations.

Station dc supply failures are not included in the screening to identify buses to be tested because two independent station dc supplies is believed not to be a common design practice. Rather than include station dc supply attributes in identifying buses to be tested, the Request for Data or Information requests reporting of station dc supply attributes separate from the Protection System attributes.

Reporting

Are the periodic status reports and data requests coordinated by the Regions, or are the reports going directly to NERC Staff?

Periodic status reports along with the actual data submittal will be directed to NERC. At the appropriate time(s) based on the schedule a web-based application will be made available for Transmission Planners to submit their reports and data.

The data gathered is highly critical to the operation of the power system. Who will have access to this data? How will it be secured from unintended access?

NERC will aggregate the data supplied by each entity for analysis. The result will not be entity specific and will be presented in such a manner as not to identify entities or vulnerabilities. In teams of access, the appropriate NERC staff will have access to the data for analysis and reporting. The collected data will be secured within NERC's secure resources.

Does the Request for Data or Information ask for the level of burden for the entities? This is not a question on the Comment Form.

The Request for Data or Information does not request entities to report on the level of burden for entities. To the extent registered entities believe the burden will be significant or require more time than proposed in the draft Request for Data or Information, entities may submit information on this subject during the 45-day comment period that ends on February 6, 2012.

The survey should include reporting on the attribute of Table B that causes the performance issue so that there can be a priority to rectify.

The intent of the Request for Data or Information is to identify whether there is a reliability concern associated with the assessment of single points of failure on Protection Systems. The method in the request has been designed to mitigate the burden on entities and as such will not provide information regarding which specific Protection System attributes may cause specific performance issues. However, the data collected will include the Protection System attributes where potential reliability risks exist to assist NERC in assessing whether there is a reliability concern and if so, whether it is related to specific Protection System components.

In the reporting template, is the tab labeled "Step Down Transformers" for reporting information on distribution transformers?

The tab labeled “Step-Down Transformers” would include reporting for distribution transformers that step voltage down from a voltage 100 kV or higher to a voltage below 100 kV. However, this tab is not exclusively for distribution transformers. This tab also will be used for collecting data on other transformers that step voltage down from a voltage 100 kV or higher to a voltage below 100 kV, such as those supplying sub-transmission networks, auxiliary power during start-up and shut-down of generators, or off-site power to nuclear generating stations. A clarifying note will be added to that tab.

What documentation is needed by NERC to prove a system is fully redundant and therefore should be excluded from the bus list?

Supporting evidence is not required to support responses to this Request for Data or Information.

Table B does not provide enough examples and detail to determine if protections system attributes that need to be evaluated meet single point of failure requirements in Table B? Will there be additional guidelines or appendices to clarify these details?

Examples will be added to the final version of the Request for Data or Information.

Schedule

When do you anticipate the actual data request will be due to NERC?

The requested data will be due to NERC 12 months after the Request for Data of Information is sent to registered entities. The anticipated due date will be on or around April 1, 2013.

The last page of the Request for Data or Information draft is a form which requests Transmission Planning Entity Contact Information. What is the deadline for this form? Is this the form that has to be filled out as acknowledgement of the request for data by the 2nd month of the schedule?

NERC will be providing the responsible entities an electronic method to enter their respective contact information concerning the data request by the 2nd month. Each entity may be provided an electronic approval process to complete their data submittal in the last 60 days of the period; however, each entity will be required to submit the approval form of the data request to NERC using the supplied address near the beginning.

The requirement is to accomplish this task in one year. If it takes Transmission Planning most of that time to identify the buses and elements that need to be reviewed, there would be little time left for the Transmission Owners and Generator Owners to finish their review. The Transmission Owners and Generator Owners may need additional time to accomplish their review beyond the one-year time frame.

The schedule in the draft Request for Data or Information is intended to provide Transmission Planners adequate time to work interactively with their Transmission Owners and Generator Owners. Entities that have concerns with the schedule may provide comments, including details of concerns and proposals for mitigation, during the 45-day comment period that ends on February 6, 2012.

General

Where on NERC's site will information be posted?

The streaming webinar and a copy of the presentation slides are posted on the NERC website at http://www.nerc.com/page.php?cid=1|83 under the tab titled "2012 Webinars." This page can be reached from the main NERC website page by clicking on the "Webinars" button on the right side of the page. Other information related to FERC Order No. 754 is posted on the NERC website at http://www.nerc.com/filez/standards/order_754.html.

Many of the hyperlinks in the Request for Data or Information do not work and URLs are not provided. It will be beneficial if they work.

The hyperlinks in the document will be updated in the final version of the Request for Data or Information. In the interim, the following hyperlinks and URLs are provided for the missing hyperlinks:

NERC SPCTF technical paper, Protection System Reliability – Redundancy of Protection: http://www.nerc.com/docs/pc/spctf/Redundancy_Tech_Ref_1-14-09.pdf.

NERC Reliability Standard TPL-001-2, Transmission System Planning Performance Requirements: http://www.nerc.com/files/TPL-001-2.pdf.

NERC Reliability Standard TPL-004-0, TPL-004-0 System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D): http://www.nerc.com/files/TPL-004-0.pdf.

Please confirm that the Request for Data or Information instructions have precedence over the notes in the data reporting template (Excel spreadsheet) if conflicts exists.

The instructions in the Request for Data or Information have precedence of the notes in the template. Entities who believe there are conflicts between the instructions in the Request for Data or Information and the reporting template may submit comments on this subject during the 45-day comment period that ends on February 6, 2012. NERC will address all identified conflicts prior to issuing the final Request for Data or Information.

The lead in at http://www.nerc.com/docs/standards/dt/Order_754_-_Data_Request_Outline_DRAFT_2011_12_01.pdf states "violations of applicable thermal or voltage ratings". Is the use of the term 'violations' correct in this context (what NERC performance criteria is being violated?)?

The referenced document was a working draft outline used during development of the Request for Data or Information. Subsequent to developing the referenced outline, the performance criteria were modified as presented in Table C. The Request for Data or Information does not require consideration of applicable thermal or voltage ratings.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Order 754 – Data Request

The study of Single Point of Failure

January 5, 2012

RELIABILITY | ACCOUNTABILITY






NERC Antitrust Guidelines and Public Meeting Disclaimer

- NERC Antitrust Guidelines
  - It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition. It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.
- NERC Disclaimer
  - Participants are reminded that this meeting is public. Notice of the meeting was posted on the NERC website and widely distributed. Participants should keep in mind that the audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

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Overview

- Summary of FERC Order 754
- October 24-25, 2011 FERC Technical Conference
- SPCS/TIS Joint Meeting Outcomes
  - Request for Data or Information
- RoP, Section 1600 background
  - Authority
  - Criteria
- Data Request
- Posted for Informal Comment
- Questions and Answers Session

Summary of Order 754

- Order 754[1]
  - Commission's approval of Project Interpretation of TPL-002-0b — PacifiCorp (Project 2009-14[2])
  - Commission has a concern (P19)
    - Study of a single point of failure on protection systems
  - Commission issued a directive (P20)
    - FERC staff to meet with NERC and appropriate SMEs
      - Explore the reliability concern
    - NERC to make an informational filing in six months (March 15, 2012)
      - Explain whether there is a further system protection issue and, if so:
      - What forum to address the issue?
      - What priority based on current initiatives?

[1] http://www.ferc.gov/whats-new/comm-meet/2011/091511/E-4.pdf

[2] http://www.nerc.com/filez/standards/Project2009-14_Interpretation_TPL-002-0_PacifiCorp.html

Technical Conference

- FERC Technical Conference (October 24-25, 2011)
  - Well attended by industry
    - Stakeholders, NERC and FERC staff
  - Discussions were open and helpful
    - 8 presentations
  - Outcomes
    - 4 Consensus Points
    - Problem Statement
    - 3 potential approaches for addressing the issue

Consensus Points

- Performance based issue, not full redundancy issue
- Existing approved standards address requirements to assess single point of failure
- Assessments of single point of failure of non-redundant primary protection (including backup) systems need to be sufficiently comprehensive
- Lack of sufficiently comprehensive assessments of non-redundant primary protection systems is a reliability concern

Problem Statement

- *"The group perceives a reliability concern regarding the comprehensive assessment of potential protection system failures by registered entities. The group agrees on the need to study if a gap exists regarding the study and resolution of a single point of failure on protection systems."*

Approaches

- Data Request – A small group should develop a proposal to the joint SPCS/TIS committees Dec 6-7, 2011
- Interpretation Request – A small group should develop a proposal to be presented to the joint SPCS/TIS committees Dec 6-7, 2011
- Project 2009-07 – To be considered later after the review of the first two bullets above

Data Request Background

- RoP, Section 1600 – Request for Data or Information
  - Authority
    - FPA, Section 215
    - FERC, Section 39.2(d) regulations
  - Criteria
    - Describe why data is needed, its use and collection method
    - Identify the functional entity(ies)
    - Estimate of the burden on reporting entities
    - A schedule for reporting
    - Must not have a compliance use
  - Posting for Comment (45 days)
  - BOT Approval Required

SPCS/TIS Meeting Outcomes

- Data Request Goals
  - Meet the criteria of Order 754
  - Have clear expectations
  - Achieve the least burden on entities
  - Avoid “Compliance” space
  - Obtain quality data
    - Sufficient sample size
    - Data across all voltages > 100 kV
    - Define potential concern:
      - Potential impact on system performance
      - Risk based on attributes of “as-built” protection systems

Responsibility and Method

- Responsibility
  - Transmission Planner
  - Requires assistance from GO(s) and TO(s)
- Method
  - Assessment for a cross-section of system elements operated at > 100 kV
  - 9-step process to assess concern
    - Transmission Planner assesses potential system performance associated with a protection system single-point-of-failure
    - GO(s) and TO(s) assess exposure to single-points-of-failure where a system performance concern is identified

Rationale and Schedule

- Rationale
  - Provides background on selection of:
    - Buses to be evaluated
    - Protection system components to be evaluated
    - System condition to be studied
    - System performance measure
- Schedule
  - Periodic reports
  - Completion due date

Data Reporting

- Reporting template
  - Reporting template provided as a tool to assist entities
  - Further guidance to be provided on the reporting method
- Data to be reported
  - Statistics concerning the buses evaluated
  - Statistics concerning attributes of protection systems
    - Protective relays
    - Communication systems
    - AC current and voltage inputs
    - DC control circuitry
  - Statistics concerning the attributes of station dc supplies

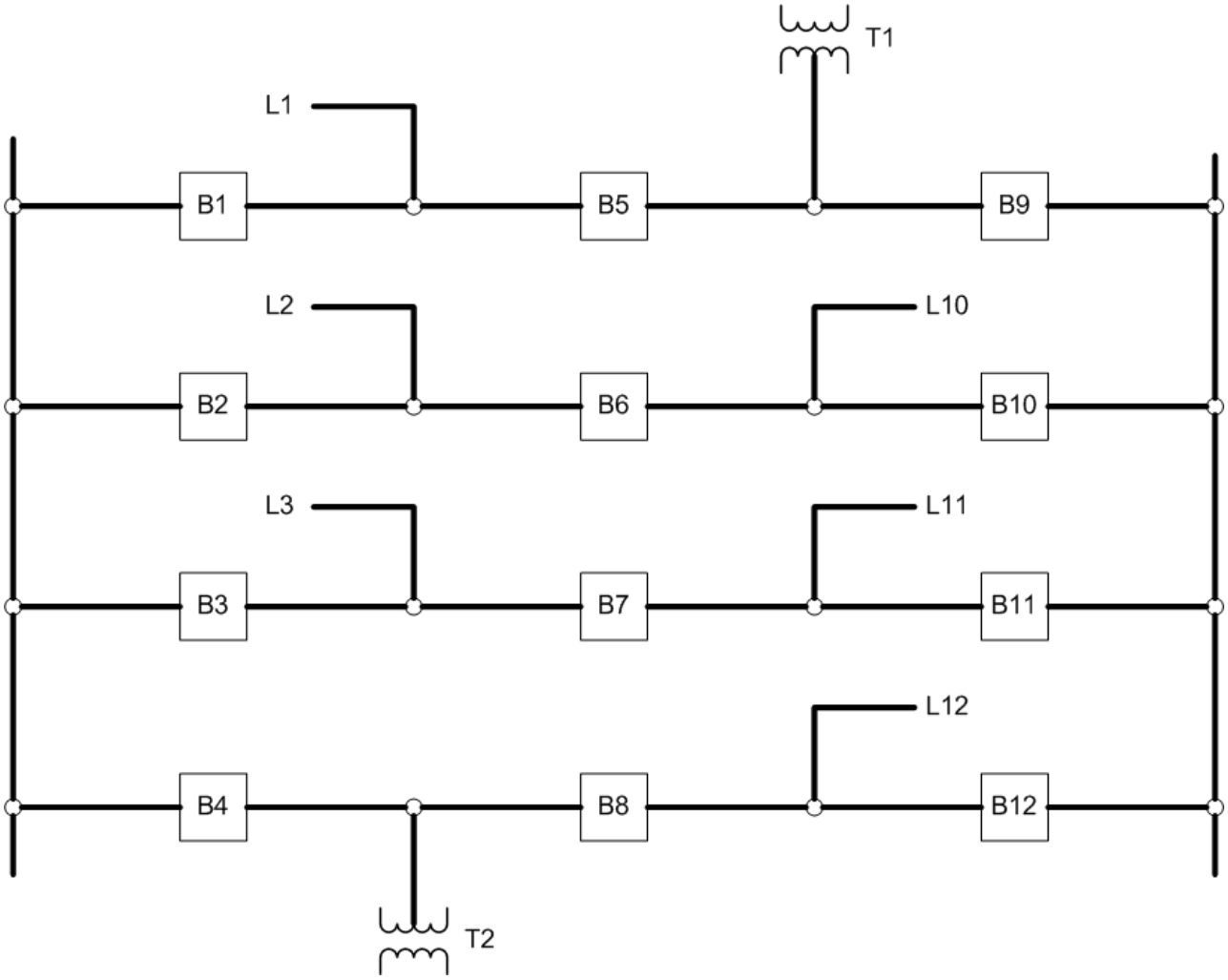
Posted for Comment

- Informal Comment Period
  - 45 days, ending February 6, 2012
  - Use website for submitting comments
  - Summary consideration of comments
- Desired comment feedback
  - Method
  - Template
  - Schedule
  - Other items

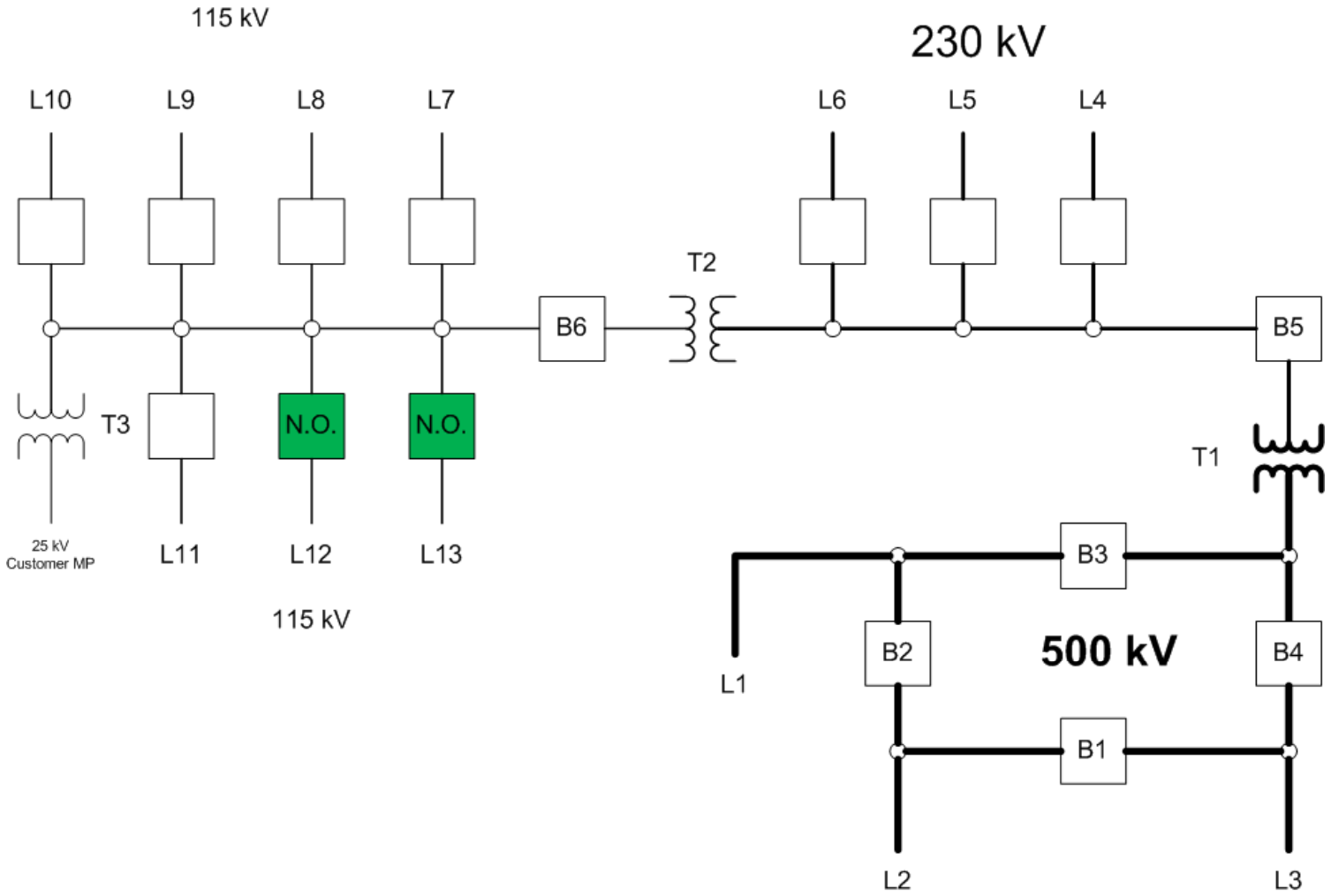
Questions and Answers

- Please submit your questions via the chat feature in ReadyTalk
- The presenters will respond to as many questions as possible during remainder of the scheduled webinar
- Complete slide set will be posted tomorrow on the Order 754 project page in the “Standards Under Development” area

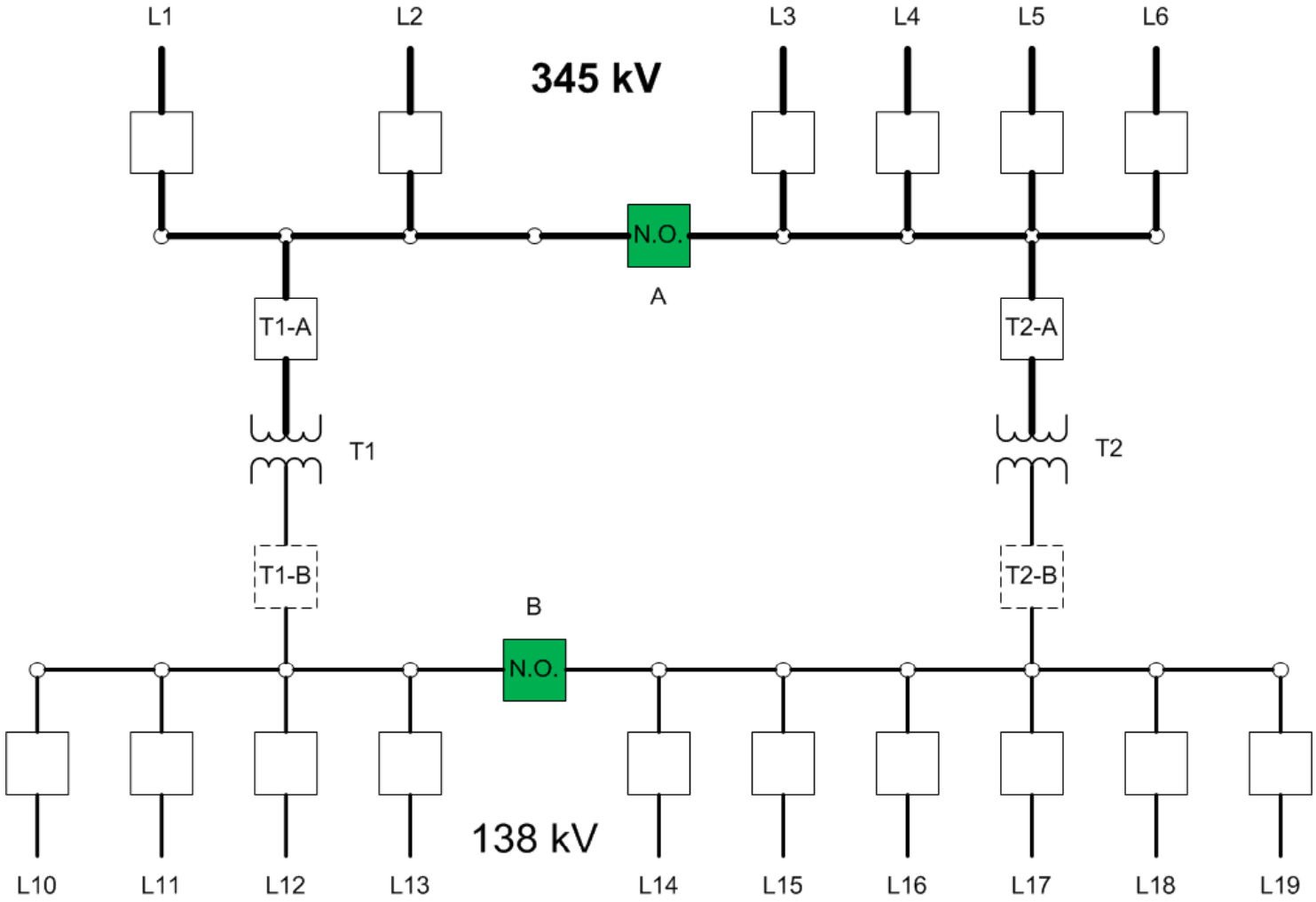
Breaker and a Half



Ring Bus


115 kV
230 kV
L10
L9
L8
L7
L6
L5
L4
T2
B6
B5
T3
N.O.
N.O.
T1
25 kV
Customer MP
L11
L12
L13
115 kV
B3
B2
500 kV
B4
L1
B1
L2
L3

Additional Buses



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Order 754 – Data Request

The study of Single Point of Failure

January 20, 2012

RELIABILITY | ACCOUNTABILITY






NERC Antitrust Guidelines and Public Meeting Disclaimer

- NERC Antitrust Guidelines
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- NERC Disclaimer
  - Participants are reminded that this meeting is public. Notice of the meeting was posted on the NERC website and widely distributed. Participants should keep in mind that the audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

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Overview

- Summary of FERC Order 754
- October 24-25, 2011 FERC Technical Conference
- SPCS/TIS Joint Meeting Outcomes
  - Request for Data or Information
- RoP, Section 1600 background
  - Authority
  - Criteria
- Data Request
- Posted for Informal Comment
- Questions and Answers Session

Summary of Order 754

- Order 754[1]
  - Commission's approval of Project Interpretation of TPL-002-0b — PacifiCorp (Project 2009-14[2])
  - Commission has a concern (P19)
    - Study of a single point of failure on protection systems
  - Commission issued a directive (P20)
    - FERC staff to meet with NERC and appropriate SMEs
      - Explore the reliability concern
    - NERC to make an informational filing in six months (March 15, 2012)
      - Explain whether there is a further system protection issue and, if so:
      - What forum to address the issue?
      - What priority based on current initiatives?

[1] http://www.ferc.gov/whats-new/comm-meet/2011/091511/E-4.pdf

[2] http://www.nerc.com/filez/standards/Project2009-14_Interpretation_TPL-002-0_PacifiCorp.html

Technical Conference

- FERC Technical Conference (October 24-25, 2011)
  - Well attended by industry
    - Stakeholders, NERC and FERC staff
  - Discussions were open and helpful
    - 8 presentations
  - Outcomes
    - 4 Consensus Points
    - Problem Statement
    - 3 potential approaches for addressing the issue

Consensus Points

- Performance based issue, not full redundancy issue
- Existing approved standards address requirements to assess single point of failure
- Assessments of single point of failure of non-redundant primary protection (including backup) systems need to be sufficiently comprehensive
- Lack of sufficiently comprehensive assessments of non-redundant primary protection systems is a reliability concern

Problem Statement

- *"The group perceives a reliability concern regarding the comprehensive assessment of potential protection system failures by registered entities. The group agrees on the need to study if a gap exists regarding the study and resolution of a single point of failure on protection systems."*

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Approaches

- Data Request – A small group should develop a proposal to the joint SPCS/TIS committees December 6-7, 2011
- Interpretation Request – A small group should develop a proposal to be presented to the joint SPCS/TIS committees December 6-7, 2011
- Project 2009-07 – To be considered later after the review of the first two bullets above

Data Request Background

- RoP, Section 1600 – Request for Data or Information
  - Authority
    - FPA, Section 215
    - FERC, Section 39.2(d) regulations
  - Criteria
    - Describe why data is needed, its use and collection method
    - Identify the functional entity(ies)
    - Estimate of the burden on reporting entities
    - A schedule for reporting
    - Must not have a compliance use
  - Posting for Comment (45 days)
  - BOT Approval Required

SPCS/TIS Meeting Outcomes

- Data Request Goals
  - Meet the criteria of Order 754
  - Have clear expectations
  - Achieve the least burden on entities
  - Avoid “Compliance” space
  - Obtain quality data
    - Sufficient sample size
    - Data across all voltages > 100 kV
    - Define potential concern:
      - Potential impact on system performance
      - Risk based on attributes of “as-built” protection systems

Data Request Overview

- Purpose: Identify whether there is a reliability concern associated with the assessment of single points of failure on protection systems
- The data collected will enable NERC
  - To assess whether there is a reliability concern, and if so
  - Determine whether it is related to specific protection system components
- The data request covers the following subjects:
  - Method
  - Rationale
  - Schedule
  - Data Reporting

Responsibility

- Responsible Entities
  - Transmission Planners
  - Requires assistance from Generator Owners and Transmission Owners
- Data request will be sent to all registered entities in the United States and Canada
- The data request is mandatory for registered entities in the United States
  - FPA, Section 215
  - FERC, Section 39.2(d) regulations
- Registered entities in Canada are strongly encouraged to submit data so that decisions regarding this concern are based on complete data across North America

Method

- Assessment for a cross-section of system elements operated at > 100 kV
  - Provide representative sample without testing all elements
- 9-step process to assess concern
  - Transmission Planner assesses potential system performance associated with a protection system single-point-of-failure
  - Generator Owners and Transmission Owners assess exposure to single-points-of-failure where a system performance concern is identified
- Utilizes existing analysis where possible

Step 1

1. Each Transmission Planner will meet with Transmission Owners and Generator Owners in its transmission planning area to identify the following:
   - Any bus from Table A, “Buses to be Tested,” that can be excluded from testing on the basis that the protection system(s) for all elements connected to the bus and for the physical bus(es), if any, meet the attributes for all categories in Table B, “Protection System Attributes to be Evaluated,” based on the Transmission Owner’s or Generator Owner’s “as-built” knowledge of the protection system(s).
   - Transformers with through-fault protection and at least one winding connected at a bus to be tested.

Buses To Be Tested

- For the purposes of this testing, all bus configurations will be treated as a straight bus (single-breaker) configuration
  - Considers all elements at one voltage in a substation to be connected to the bus (unless electrically separated)
- Testing is based on a fault on the bus
  - Minimizes burden on registered entities
  - Representative of a close-in fault on any element connected to the bus

List of Buses to be Tested

- The purpose of Step 1 is to develop a list of buses to be evaluated by the Transmission Planner
  - Initial list based on Table A
  - List reduced based on TO/GO input
    - Exclude buses when all elements meet the attributes for all categories in Table B based on TO/GO “as-built” knowledge of the protection systems

Note: This clarification will be added in the final data request

Table A

Table A: Buses to be Tested
Buses operated at 200 kV or higher with 4 or more circuits
Buses operated at 100 kV to 200 kV with 6 or more circuits
Buses operated at 100 kV or greater with 4 or more circuits and at which a bus fault and tripping of all connected elements at the remote terminals will result in 300 MW or more of consequential load loss as a result of remote clearing
Buses with aggregate generation of 1,000 MW or higher
Buses directly supplying off-site power to a nuclear generating station
Any additional buses the Transmission Planner believes are necessary for the reliable operation of the BES

***Note**: For purposes of applying Table A, circuits include transmission lines, transmission transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher, and generator step-up transformers.*

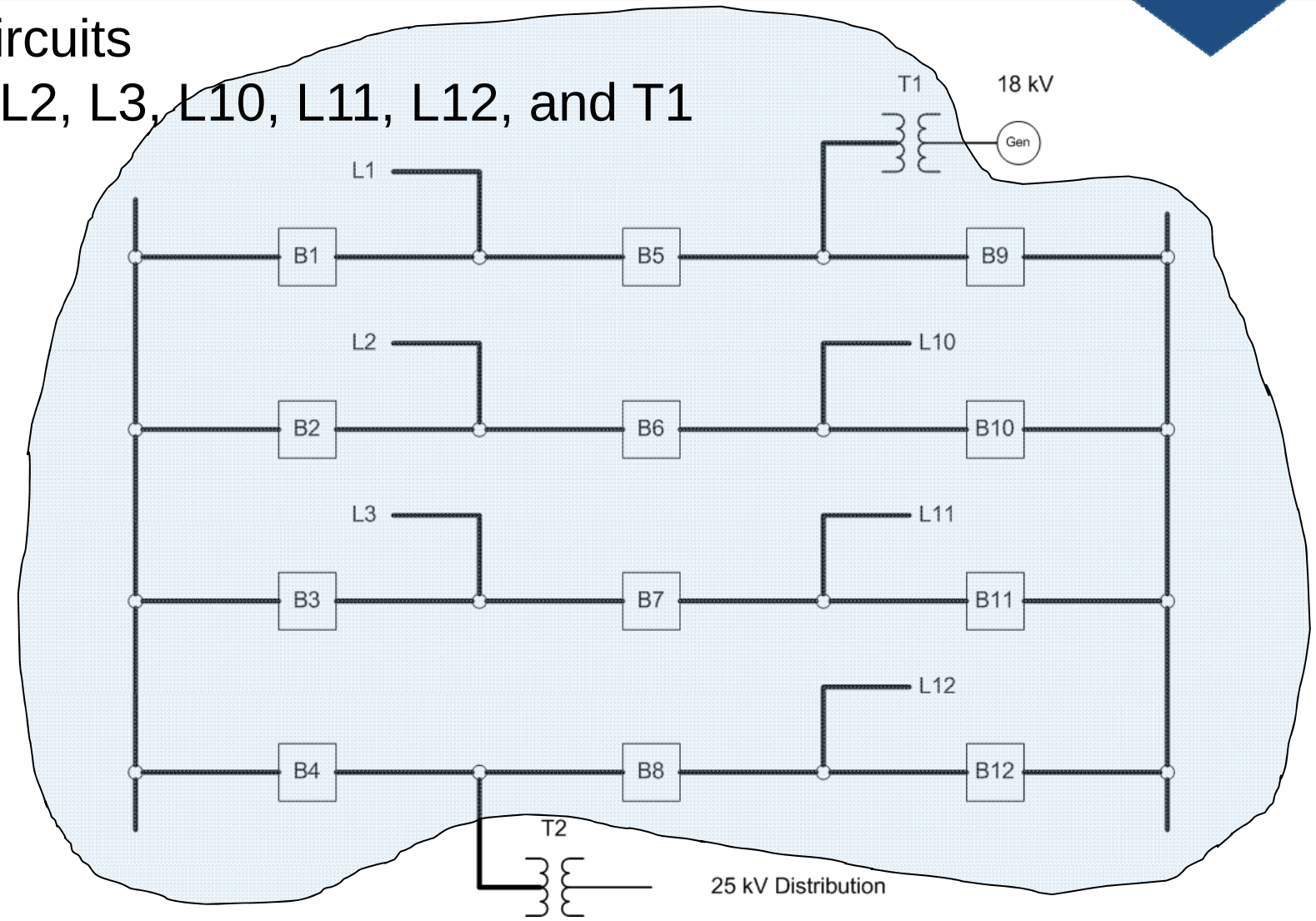
Table B

Table B: Protection System Attributes to be Evaluated
Protective Relays: The protection system for the element includes two independent protective relays that are used to measure electrical quantities, sense an abnormal condition such as a fault, and respond to the abnormal condition.
Communications Systems: The protection system for the element includes two independent communication channels and associated communication equipment when such communication between protective relays is needed to satisfy BES performance required in the TPL standards.
AC Current and Voltage Inputs: The protection system includes two independent ac current sources and related inputs and two independent ac voltage sources and related inputs, except that the two ac current sources may have a common primary current transformer (CT) winding and the two ac voltage inputs may have common capacitance coupled voltage transformer (CCVT), voltage transformer (VT), or similar device primary windings.
DC Control Circuitry: The protection system includes two independent dc control circuits with no common dc control circuitry, auxiliary relays, or circuit breaker trip coils.

Note: *Physical separation of protection system components is not necessary for protection system components to be reported as independent.*

Breaker-and-a-Half

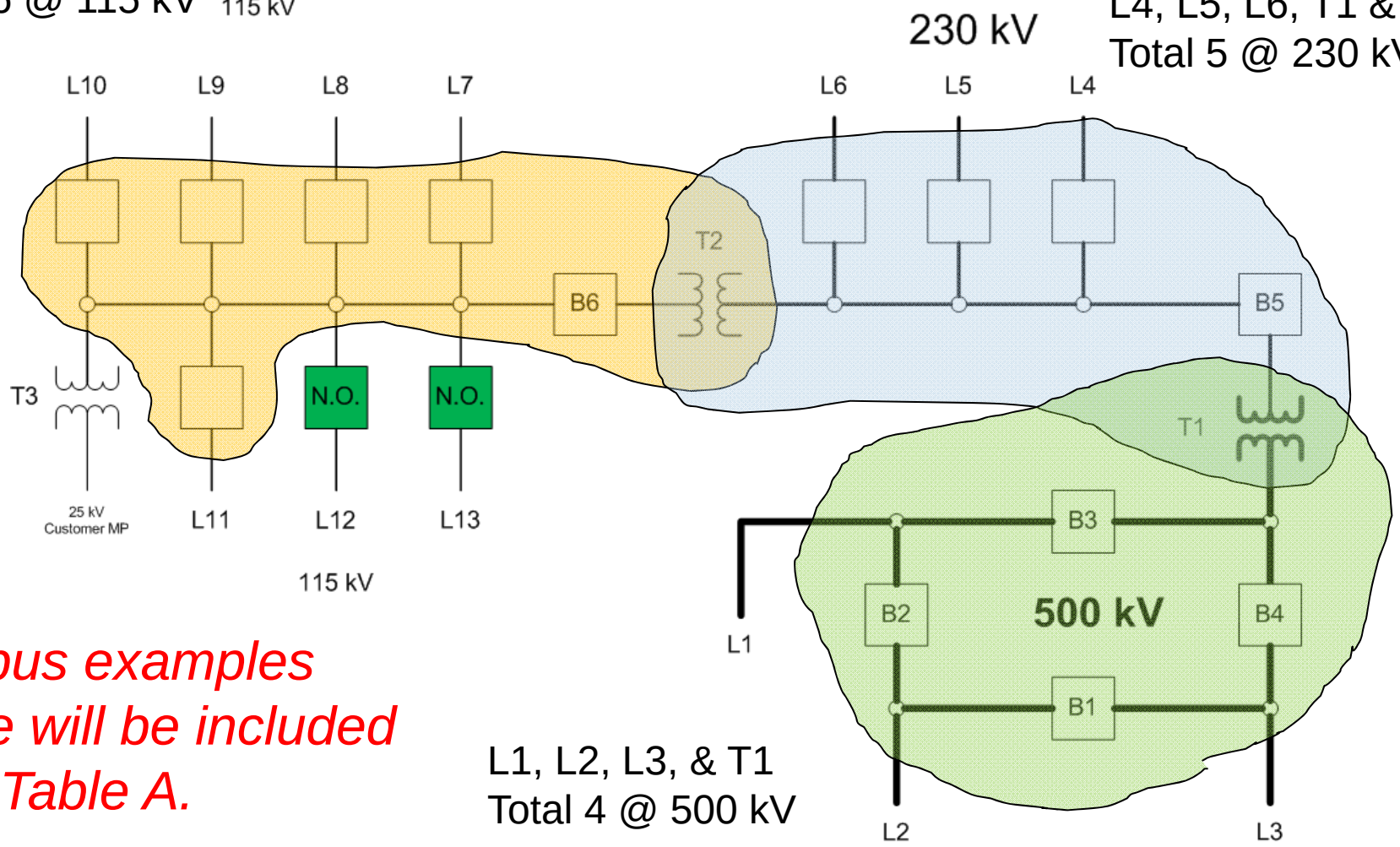
7 Circuits
L1, L2, L3, L10, L11, L12, and T1



Ring Bus

L7, L8, L9 , L10, L11, &T2
Total 6 @ 115 kV

L4, L5, L6, T1 & T2
Total 5 @ 230 kV



All bus examples here will be included per Table A.

L1, L2, L3, & T1
Total 4 @ 500 kV

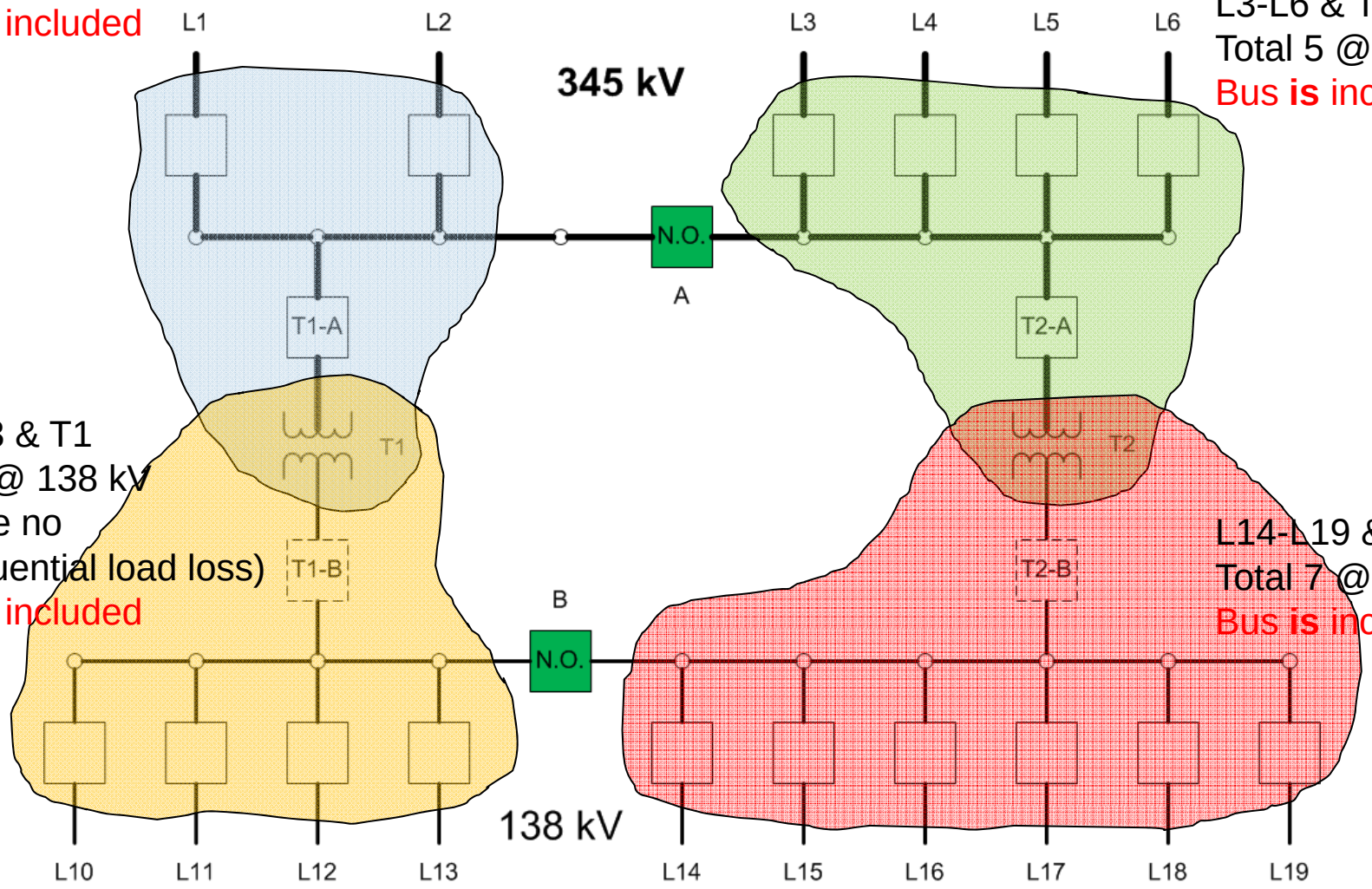
Additional Buses

L1, L2 & T1
Total 3 @ 345 kV
Bus not included

L3-L6 & T2
Total 5 @ 345 kV
Bus **is** included

L10-L13 & T1
Total 5 @ 138 kV
(assume no consequential load loss)
Bus not included

L14-L19 & T2
Total 7 @ 138 kV
Bus **is** included

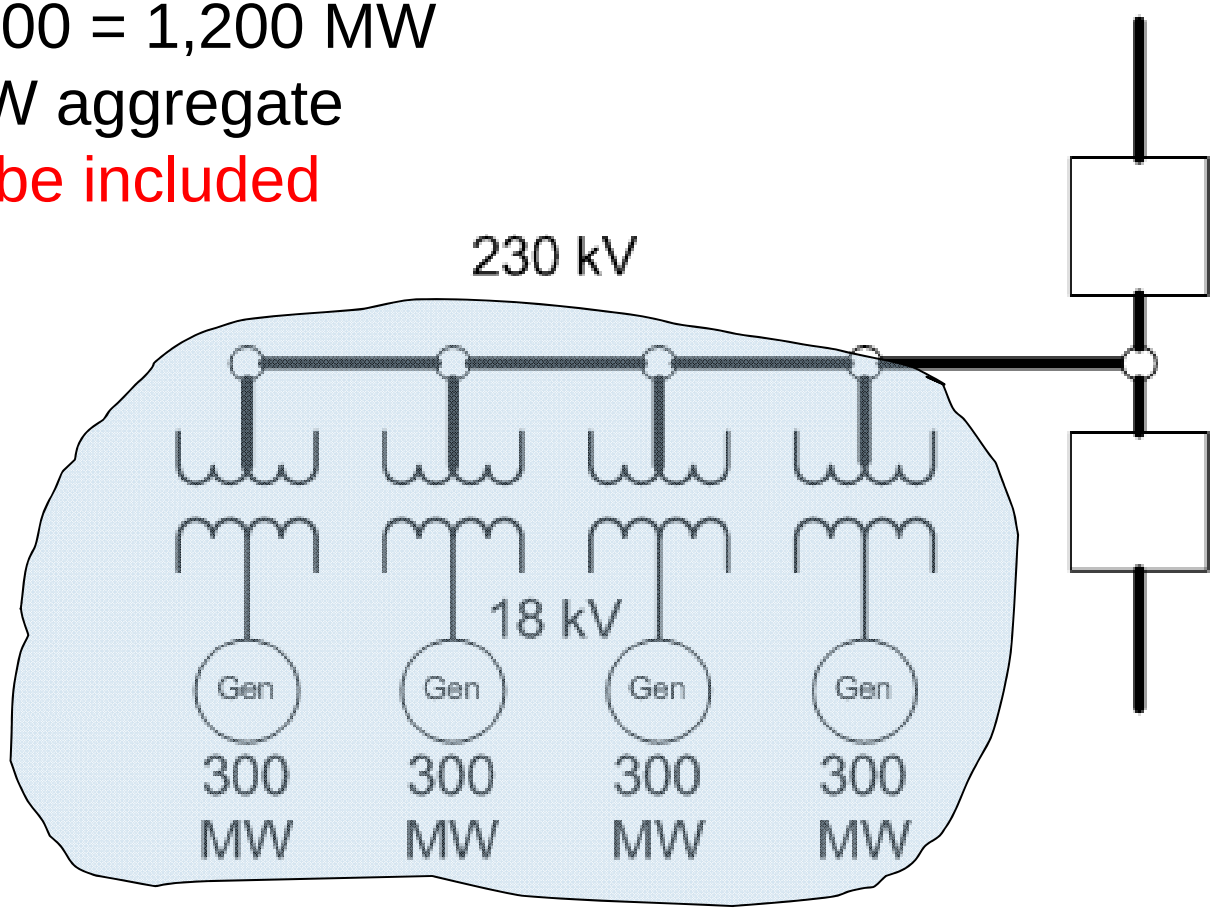


Bus with Generation

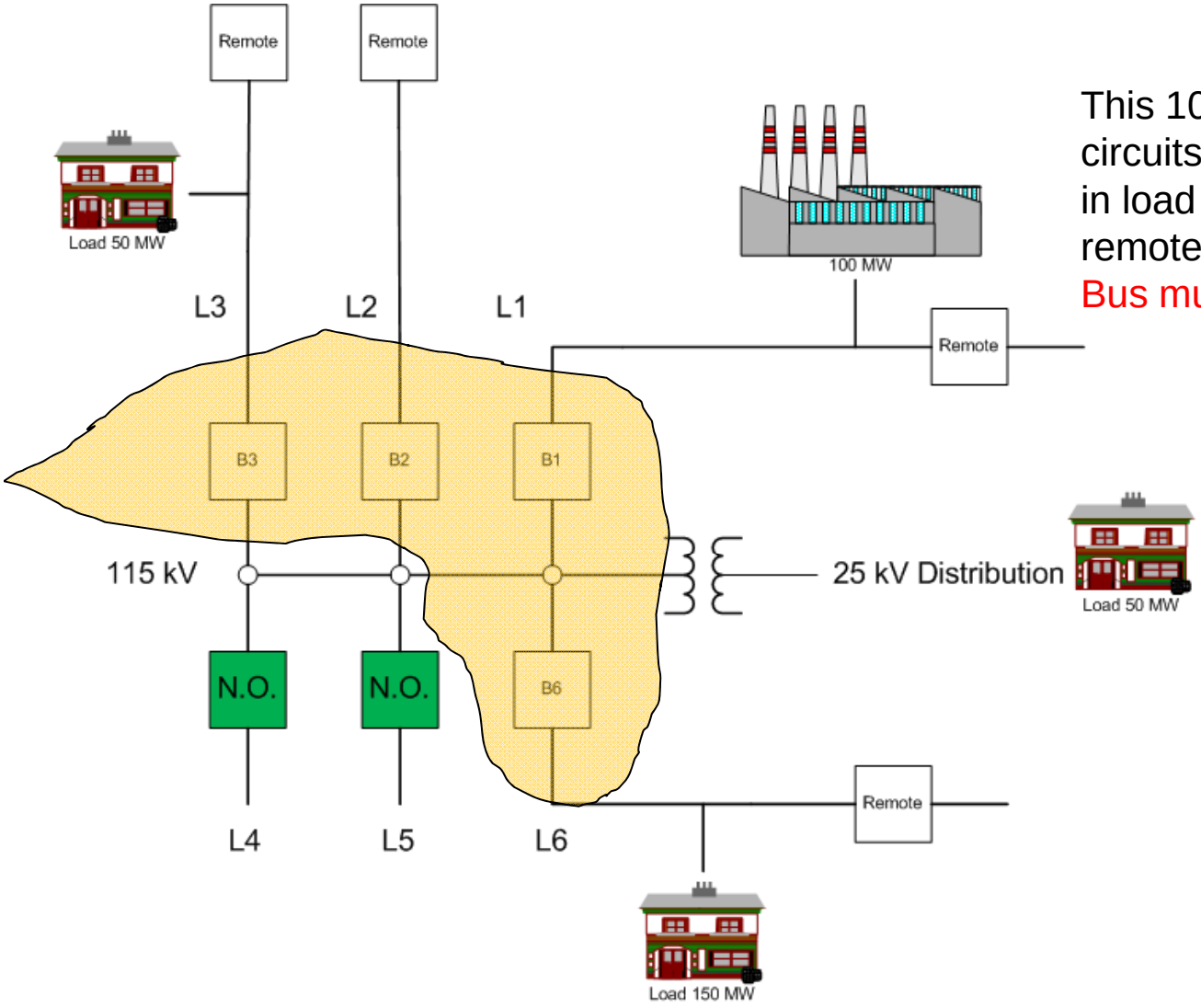
4 units x 300 = 1,200 MW

>1,000 MW aggregate

Bus must be included



100 kV & 300 MW Load Loss



This 100-200 kV bus has less than 6 circuits, but has more than 300 MW in load that would be lost during remote clearing.

Bus must be included.

Step 2

2. Each Transmission Planner will simulate a three-phase fault on each bus in its transmission planning area identified in step 1. The three-phase fault is cleared based on the following conservative simulation parameters:
   - Trip the remote terminals of all transmission lines connected to the faulted bus based on the maximum expected remote clearing time provided by the Transmission Owner or Generator Owner.
   - For each transformer connected to the faulted bus that is protected by through-fault protection, the Transmission Planner will trip the transformer at its other terminal(s) not connected to the faulted bus based on the maximum expected clearing time provided by the Transmission Owner or Generator Owner.

Note: Step 2 will be modified as shown based on clarification to Step 1

Step 2, continued

- For each transformer connected to the faulted bus that is not protected by through-fault protection, the Transmission Planner will not trip the transformer or any element connected to the other terminal(s) of the transformer not connected to the faulted bus.
- Evaluate the system response for each simulated fault against the criteria in Table C, “Performance Measures.”
- Create an initial list of buses owned by each Transmission Owner and Generator Owner at which the simulated system response exceeds at least one performance measure criteria from Table C, “Performance Measures,” and provide this initial list to each respective Transmission Owner and Generator Owner.

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Table C

Table C: Performance Measures
1. System does not maintain stability (instability of units is not indicative of system instability, but must be included in the loss of generation in measure #3)
2. Unintended system separation resulting in an island of 1,000 MW or more, not as a direct result of the remote fault clearing
3. Loss of generation of 2,000 MW or more in the Eastern Interconnection or Western Interconnection, or 1,000 MW or more in the ERCOT or Québec Interconnections (total loss of generation includes generation disconnected as a direct result of the remote fault clearing and includes generating units that do not maintain stability)

Step 3

3. The Transmission Owner and Generator Owner will evaluate the protection system(s) for each element connected at each bus identified by the Transmission Planner in step 2 and for the physical bus(es), if any, to determine whether a single point of failure exists due to not meeting the attributes for any category in Table B, “Protection System Attributes to be Evaluated.”

Step 4

4. The Transmission Owner and Generator Owner will provide the Transmission Planner with a revised list of buses at which a single point of failure exists on any element for any component category in Table B. This revised list will be used by the Transmission Planner in steps 5 and 6 to reassess the conservative simulations performed in step 2.

Step 5

5. The Transmission Planner will consult with the Transmission Owner and the Generator Owner regarding actual clearing times for all elements that will trip for a fault on each bus identified on the revised list of buses provided in step 4.

The actual clearing time is the time calculated by the Transmission Owner or Generator Owner at which the remote terminals of elements will trip for a three-phase fault on the bus under study. In some cases, an element may not trip at its remote terminals if the protection system at those terminals will not detect the fault. In such cases, the fault will remain un-cleared in the simulation.

Step 6

6. The Transmission Planner will simulate a three-phase fault on each bus identified on the revised list of buses provided in step 4 using the actual clearing times provided by the Transmission Owner and Generator Owner in accordance with the method described in step 2, except that actual clearing times will be used in place of tripping elements based on the maximum expected clearing time.

By mutual agreement with the Transmission Owners and Generator Owners, the Transmission Planner may test all buses using actual clearing times provided by the Transmission Owner and Generator Owner in step 2.

Step 7

7. The Transmission Planner will update the revised list of buses owned by each Transmission Owner and Generator Owner developed in step 2, at which the simulated system response exceeds at least one performance measure criteria in Table C, "Performance Measures," and provide the final list to each respective Transmission Owner and Generator Owner.

Step 8

8. The Transmission Owner and Generator Owner will provide “as-built” information to the Transmission Planner necessary for the Transmission Planner to complete the data request reporting template. This data includes:
   - The attributes of the protection system(s) listed in Table B, “Protection System Attributes to be Evaluated,” for each bus from the final list provided by the Transmission Planner in step 7.
   - The attributes of the station dc supply listed in Table D, “Station DC Supply Attributes to be Reported,” for each bus that meet the criteria in Table A, “Buses to be Evaluated.”

Table D

Table D: Station DC Supply Attributes to be Reported
The protection system includes two independent station dc supplies
The protection system includes one dc supply that is centrally monitored, including alarming for a battery open condition if the station dc supply is a battery
The protection system includes one dc supply that is centrally monitored, but does not include alarming for a battery open condition if the station dc supply is a battery
The protection system includes one dc supply that is not centrally monitored

Note: *A station dc supply includes one station battery, or single charger, or other single dc source.*

Step 9

9. The Transmission Planner will provide the following information in accordance with the data request reporting template.
   - Statistics concerning the buses evaluated
   - Statistics concerning the attributes of the protection system(s) associated with each identified element
   - Statistics concerning the attributes of the station dc supply at selected buses in each transmission planning area

Data reporting will be facilitated through a web-based application based on the data request reporting template provided with the data request. The accompanying template is unofficial and intended to assist the Transmission Planner. NERC will issue instructions on the method of reporting consistent with the reporting schedule.

Schedule

Period*	Activity
1st month	Starting point of the data request period
2nd month	Transmission Planners must acknowledge the request for data
4th month	Transmission Planners must report which step(s) are complete
7th month	Transmission Planners must report which step(s) are complete
10th month	Transmission Planners must report which step(s) are complete
11th month	Electronic data reporting period opens (60 days)
Last day of the 12th month	Transmission Planner data reporting must be complete

***Period** is the first calendar day of the month number following BOT approval, except as noted otherwise.

Rationale

- Developed to reduce burden on registered entities
  - Transmission Planners may utilize existing studies
  - Asset owners may utilize existing “as-built” information
- Representative sample of buses > 100 kV
  - Avoids testing all buses, but includes sample of 100-200 kV
- Collects data to identify specific areas of potential exposure
  - Protection systems
  - Station dc supply

Rationale, continued

- Three-phase faults
  - Bounds the concern with single-line-to-ground faults evolving to multi-phase
  - Facilitates use of existing analyses
- Performance measure
  - Based on system performance observed in past events that formed basis for NERC Industry Alert (March 2009)

Data Reporting

- Reporting template
  - Reporting template provided as a tool to assist entities
  - Further guidance to be provided on the reporting method
- Data to be reported
  - Statistics concerning the number of buses evaluated
  - Statistics concerning attributes of protection systems
  - Statistics concerning the attributes of station dc supplies
- The data collection is designed to avoid skewing the data; e.g.,
  - The request for voltage transformers and current transformers excludes common primary windings
  - The request for station dc supply requests additional information regarding alarming when only one station battery is used

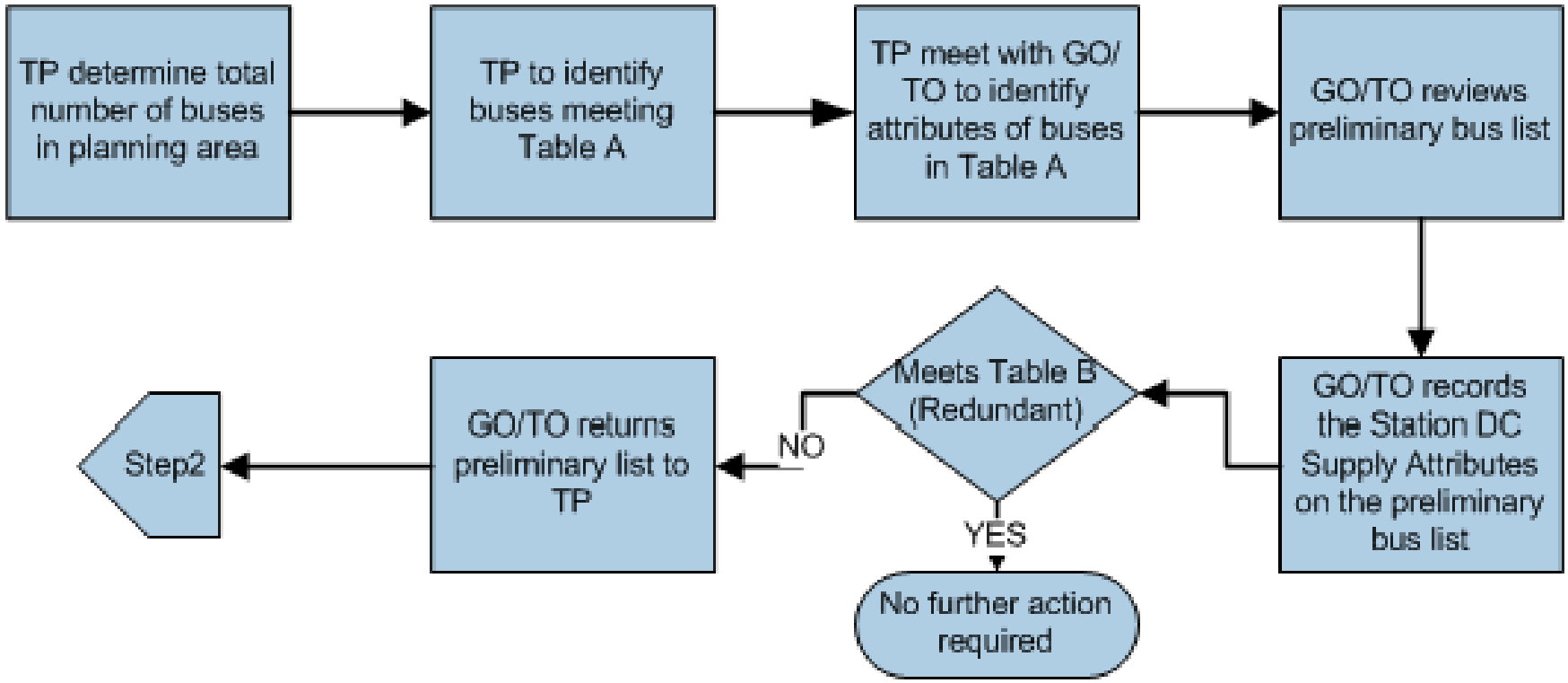
Posted for Comment

- Informal Comment Period
  - 45 days, ending February 6, 2012
  - Use website for submitting comments
  - Summary consideration of comments
- Desired comment feedback
  - Method
  - Template
  - Schedule
  - Other items
- If submitting as a group . . .

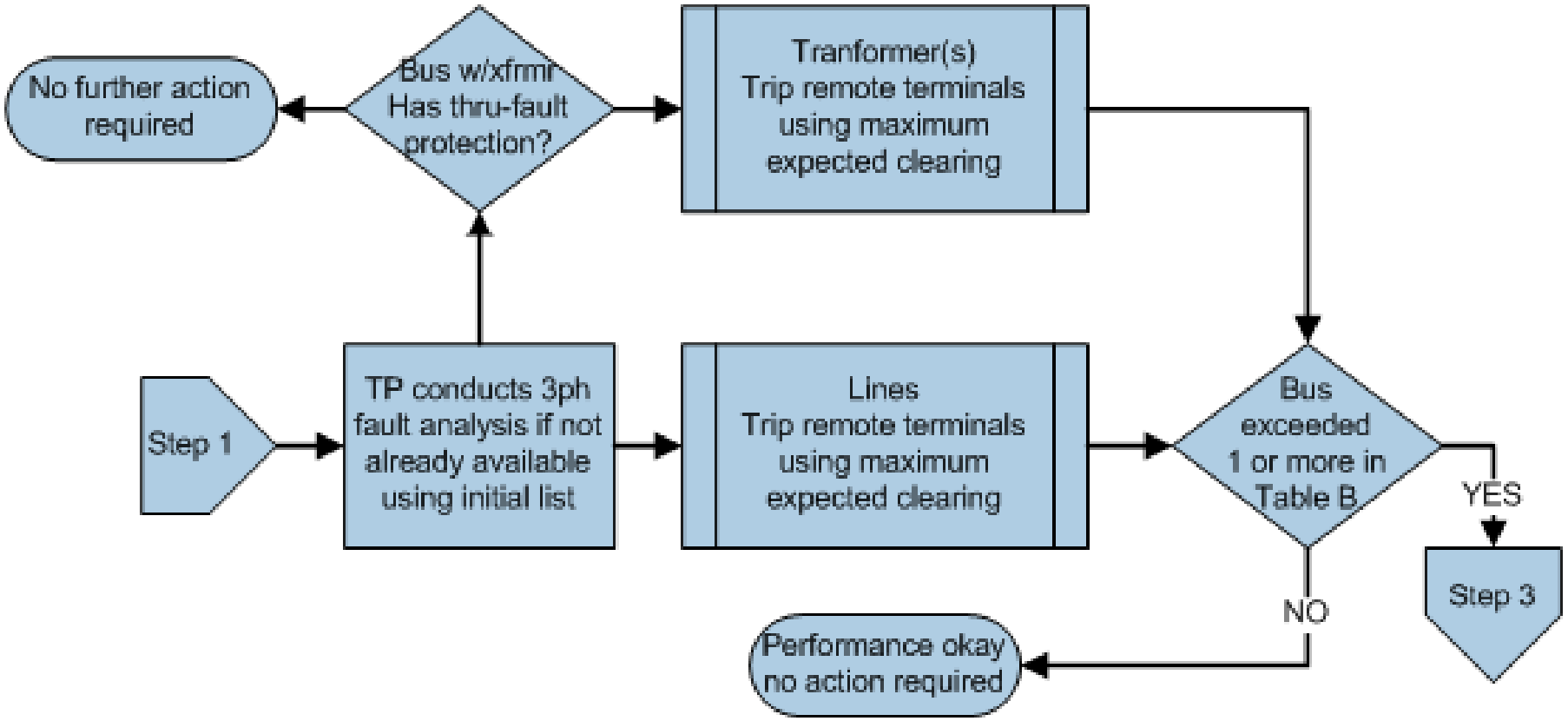
Questions and Answers

- Please submit your questions via the chat feature in ReadyTalk
- The presenters will respond to as many questions as possible during remainder of the scheduled webinar
- Complete slide set will be posted tomorrow on the Order 754 project page in the “Standards Under Development” area

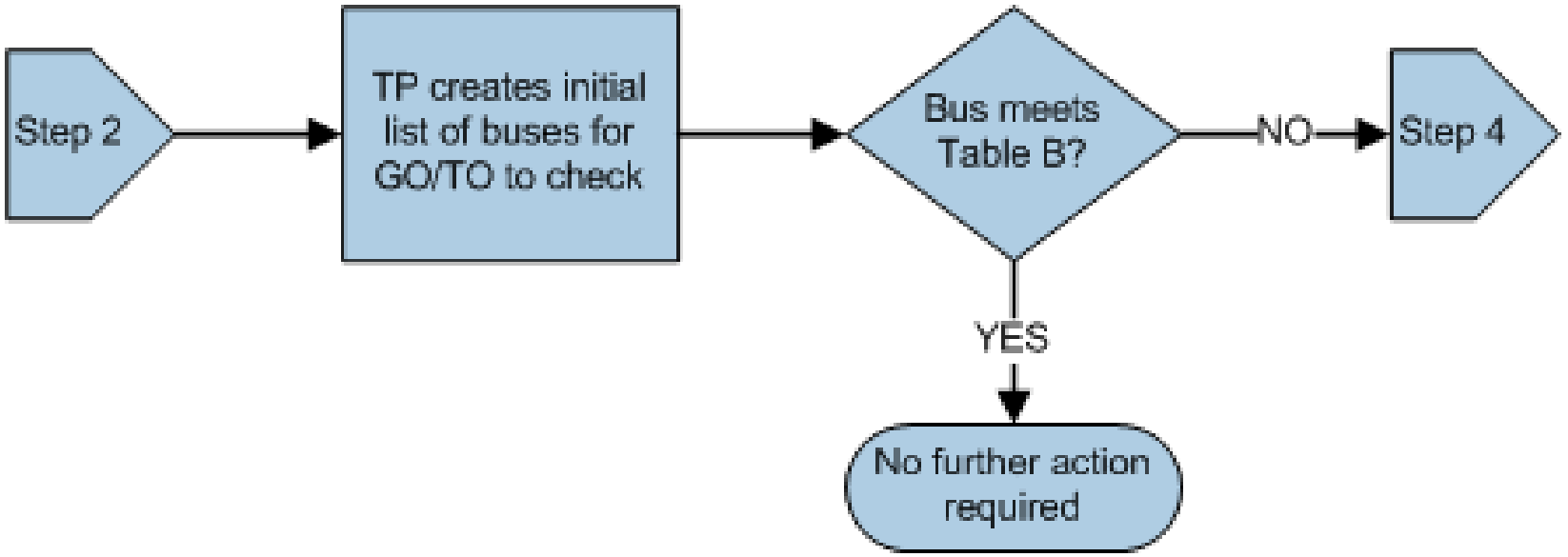
Step 1


TP determine total number of buses in planning area
TP to identify buses meeting Table A
TP meet with GO/TO to identify attributes of buses in Table A
GO/TO reviews preliminary bus list
GO/TO records the Station DC Supply Attributes on the preliminary bus list
Meets Table B (Redundant)
NO
YES
GO/TO returns preliminary list to TP
Step2
No further action required

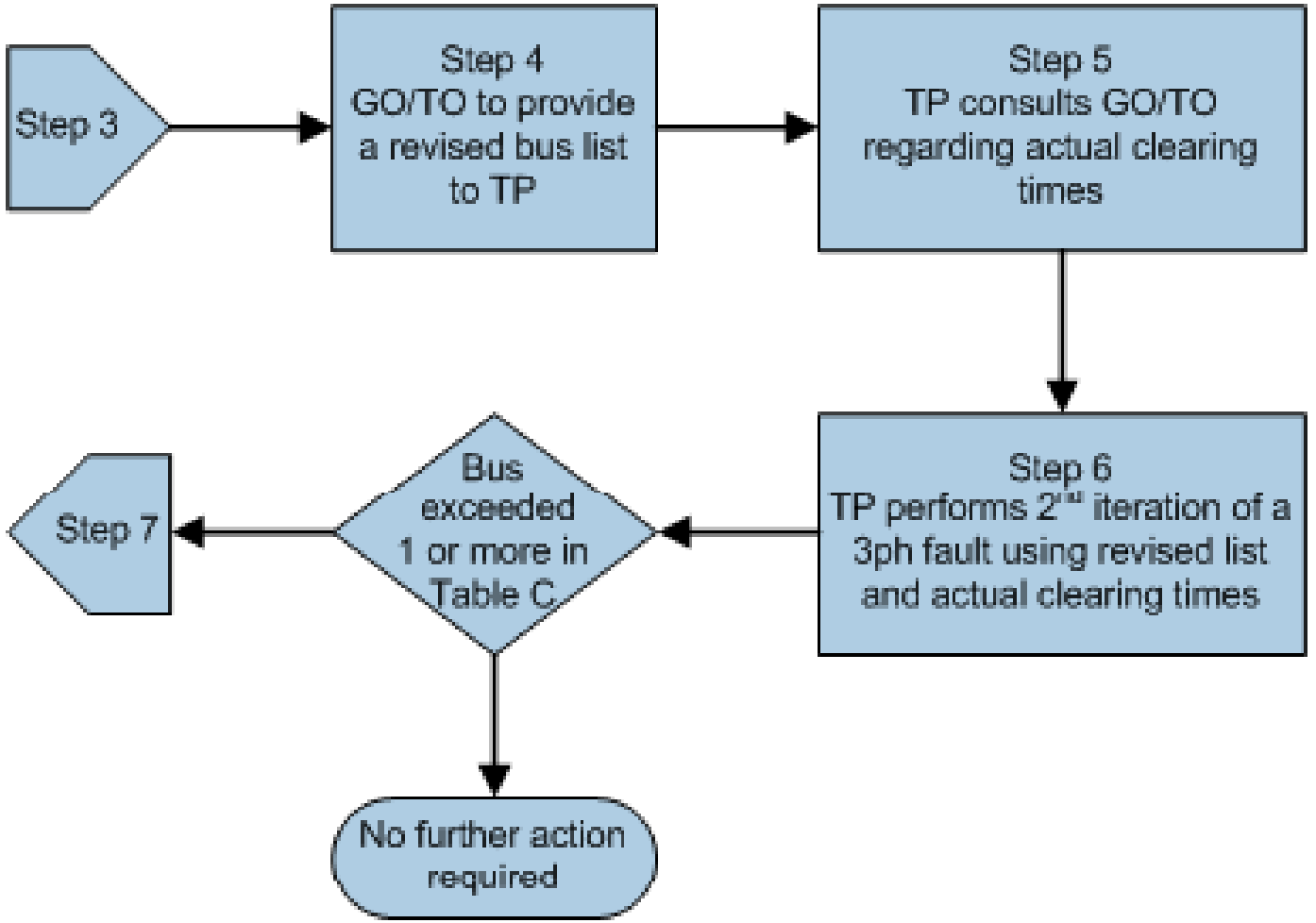
Step 2


No further action required
Bus w/xfmr Has thru-fault protection?
Tranformer(s) Trip remote terminals using maximum expected clearing
Step 1
TP conducts 3ph fault analysis if not already available using initial list
Lines Trip remote terminals using maximum expected clearing
Bus exceeded 1 or more in Table B
YES
Step 3
NO
Performance okay no action required

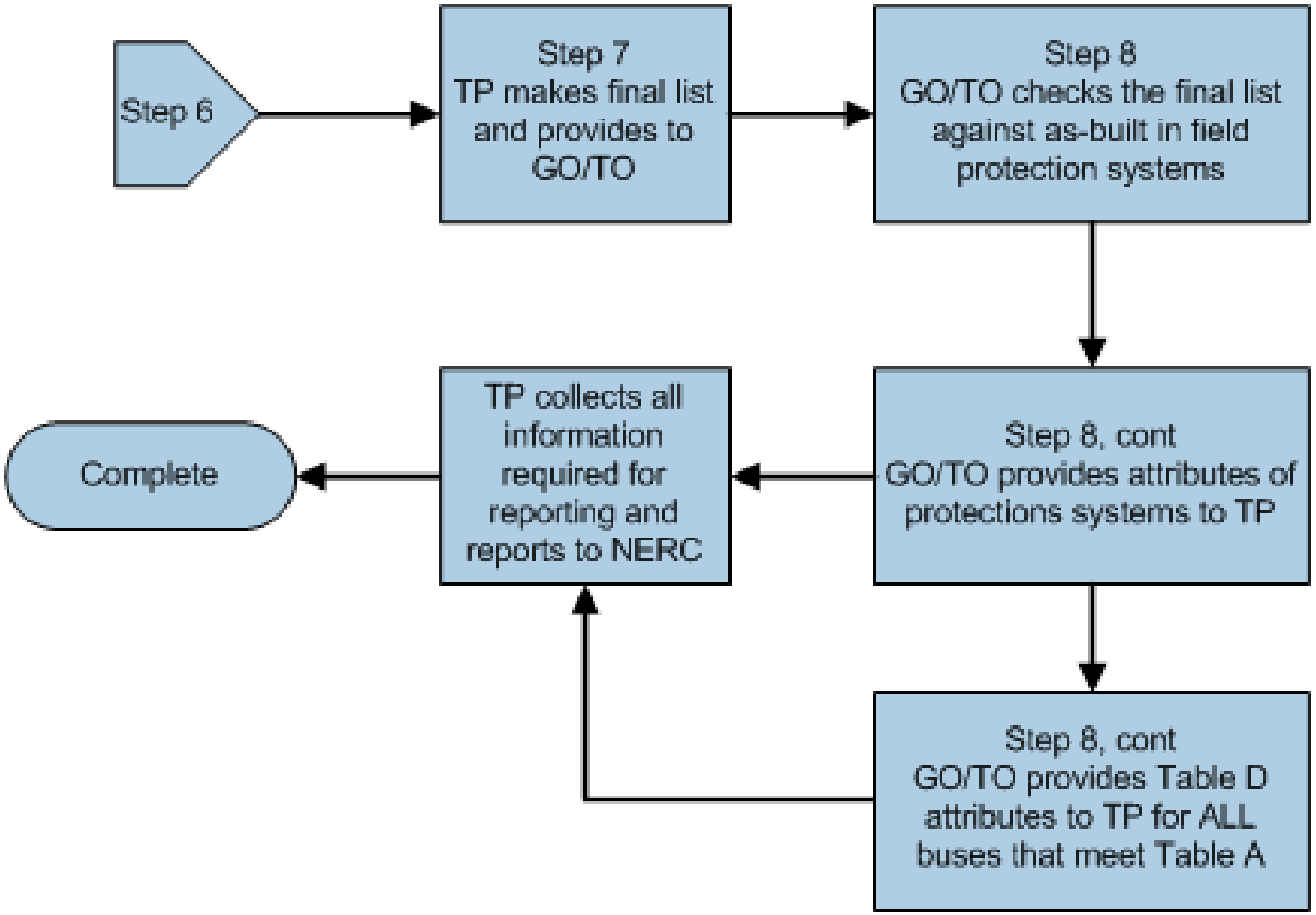
Step 3


Step 2
TP creates initial list of buses for GO/TO to check
Bus meets Table B?
NO
Step 4
YES
No further action required

Step 4 - 6


Step 3
Step 4
GO/TO to provide a revised bus list to TP
Step 5
TP consults GO/TO regarding actual clearing times
Step 6
TP performs 2nd iteration of a 3ph fault using revised list and actual clearing times
Bus exceeded 1 or more in Table C
Step 7
No further action required

Step 7 - 9


Step 6
Step 7
TP makes final list and provides to GO/TO
Step 8
GO/TO checks the final list against as-built in field protection systems
Step 8, cont
GO/TO provides attributes of protections systems to TP
Step 8, cont
GO/TO provides Table D attributes to TP for ALL buses that meet Table A
TP collects all information required for reporting and reports to NERC
Complete

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Project 2010-17 Phase 2 - Definition of BES

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the SAR. The electronic comment form must be completed by **February 3, 2012.**

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 1.609.947.3673.

2010-17 Definition of BES project page

Background Information

This posting is for soliciting comment.

This SAR is a direct result of the industry comment periods for Project 2010-17 Definition of BES Phase 1 where the industry indicated a need for further detailed examination of the technical concepts underlying the BES definition. Due to time constraints in Phase 1 brought about by the FERC Orders driving the revised definition, any expansion of the scope of Phase 1 was deferred to Phase 2 where time deadlines would be less of an issue. The language of the SAR is such that any and all aspects of the Phase 1 definition are open to discussion and possible revision. However, the SDT outlined some of the major points that were brought up in Phase 1 by bulleting them in the SAR description. The SDT does not consider this list to be an all exclusive one – it is simply a brief listing of those issues that were identified in Phase 1.

You do not have to answer all questions. Enter all comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

The scope of this project includes:

Collect and analyze information needed to support revisions to the definition of BES developed in Phase 1 of this project to provide a technically justifiable definition that identifies the appropriate electrical components necessary for the reliable operation of the interconnected transmission network. The definition development will include an analysis of the following issues which were identified during the development of Phase 1 of Project 2010-17 Definition of the BES. Clarification of these issues will appropriately define which Elements are necessary for the reliable operation of the interconnected transmission network.

- Develop a technical justification to set the appropriate threshold for Real and Reactive Resources used in the operation of the Bulk Electric System (BES)
- Determine if there is a technical justification to support the assumption that there is a reliability benefit of a contiguous BES
- Determine if there is a technical justification for the equipment which "supports" the reliable operation of the BES but is installed on the distribution system
- Determine if there is a technical justification to support an automatic interrupting device in Exclusions E1 and E3
- Determine if there is a technical justification to support the inclusion of Cranking Paths and Blackstart Resources
- Determine if there is a technical justification for selection of 100 kV as the bright-line voltage level
- Determine if there is a technical justification to support allowing power flow out of the local network under certain conditions and if so, what the maximum allowable flow should be

Provide improved clarity to the following:

- The relationship between the BES definition and the ERO Statement of Compliance Registry Criteria established in FERC Order 693
- The use of the term "non-retail generation"
- The language for Inclusion I4 on dispersed power resources
- The appropriate 'points of demarcation' between Transmission, Generation, and Distribution

Phase 2 of the definition development may include other improvements to the definition as deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing a high quality and technically justifiable definition of the Bulk Electric System (BES).

Based on the potential revisions to the definition of the Bulk Electric System (BES) and an analysis of the application of, and the results from, the exception process, the drafting team will review and if necessary propose revisions to the 'Technical Principles' associated with the Rules of Procedure Exception Process to ensure consistency in the application of the definition and the exception process.

1. Do you agree with this scope? If not, please explain.

   ☐ Yes

   ☒ No

   Comments: The primary focus of the SDT should be to ensure that the BES Definition as approved by both industry stakeholders and the NERC Board of Trustees is clear and understandable, and implemented consistently across the continent. To that end:

- Add the following scope element: Determine if there is a technical justification to support the 300 kV limitation on Local Network elements. This bright line limitation on elements which may be part of a Local Network lacks any technical justification and therefore should be included in the Phase 2 SAR.
- Revise the bullet "Determine if there is a technical justification to support the assumption that there is a reliability benefit of a contiguous BES" to: "Determine if there is a technical justification to include in the BES definition whether the BES should be contiguous." It has not been assumed that the BES must be contiguous.
- Delete the following scope element: "Determine if there is a technical justification to support the inclusion of Cranking Paths and Blackstart Resources" because it was addressed by the Phase 1 SDT. "Cranking Path" is already a defined term in the NERC Glossary and the requirement for Transmission Operators to document Cranking Paths is already stipulated in EOP-005.
- To establish Real and Reactive Power bright lines, a fixed 'bright line' approach fails to consider relative impact. For example, a 20 MVA generation resource within a 200 MW radial system may represent a significant reliability concern. However, that same 20 MVA generator within a 10,000 MW interconnected system may not be as significant because of the availability of resources to compensate for that 20MVA generator. Any BES Definition which establishes a fixed MVA threshold cannot consider the relative impacts on reliability . Any fixed Real and Reactive Resource bright line thresholds established using the most restrictive case contintent-wide will inappropriately impose excess reliability cost for little or no reliability benefit on systems everywhere small unit operation is not impactful or necessary. Propose the following language for Phase 2 Real and Reactive Resource bright line thresholds:

  "Develop a technical justification to set the appropriate threshold for Real and Reactive Resources used in the operation of the Bulk Electric System (BES). The BES Real and Reactive Resource thresholds may either be fixed (as used today), per unit, or on a system percentage basis, as may be appropriate and technically justified."
- The Phase 1 BES SDT did not define the term "local distribution facilities", although the core BES definition excludes such facilities. Add to the SAR:

Develop a technical basis and definition for the term local distribution facilities. Due consideration should be given to using the precedents identified in FERC Order 743-A.

- The Phase 1 BES SDT developed Technical Principles for the exemption of facilities from the BES. These Technical Principles are to be employed as a simplified check list of exemption factors for use by Regional review panels. A renewed effort should be made in Phase 2 to strengthen the Technical Principles. The objective should be to develop the FERC-directed "clear, objective, transparent, and uniformly applicable criteria for exemption of facilities". Suggest adding the following:
  - "Develop technical principles for the "clear, objective, transparent, and uniformly applicable criteria for exemption of facilities" for removing from the definition jurisdictional facilities not 'necessary' for the reliable operation of the Bulk Electric System."

The SDT has identified several issues that are included in the scope of Phase 2 of the project that are associated with the technical aspects of the definition and require technical justification to drive a revision to the definition. Compelling technical justification is an essential component in moving any revision forward that addresses the technical nature of the BES definition. The SDT is seeking to identify existing technical justifications (i.e., completed studies, technical papers, etc.) and requests your assistance to properly identify resources available to the SDT which will facilitate the SDT's work in prioritizing its efforts.

Note: The SDT does not intend to respond to all responses associated with an entity's knowledge of existing technical justification (i.e. analysis methodologies, completed studies, technical papers, etc.). The SDT is collecting potential resources that could assist in the development of compelling technical justification.

2. Do you agree that the SDT should pursue the development of technical justification to set thresholds for Real and Reactive Power Resources used in the reliable operation of the BES different from those presently existing in the BES definition?

   ☒ Yes

   ☐ No

   Comments: Refer to the response to Question 1.

   Resources greater than a certain threshold should be classified as BES elements and be required to adhere to all relevant reliability standards. The threshold need not be a fixed

MVA level, but could be either fixed (as used today), per unit, or on a system percentage basis, as may be appropriate and technically justified. Propose the following language for Phase 2 Real and Reactive Resource bright line thresholds: "*Develop a technical justification to set the appropriate threshold for Real and Reactive Resources used in the operation of the Bulk Electric System (BES). The BES Real and Reactive Resource thresholds may either be fixed (as used today), per unit, or on a system percentage basis, as may be appropriate and technically justified*."

a. Are you aware of existing technical justification (i.e., analysis methodologies, completed studies, technical papers, etc.) that would assist the SDT in the development of technical justification for this issue? If so, please provide details in the 'Comments' field.

☐ Yes

☒ No

Comments:

3. Do you agree that the SDT should pursue technical justification that supports the assumption that there is a reliability benefit of a contiguous BES?

☒ Yes

☐ No

Comments: Refer to the response to Question 1 regarding the contiguous BES.

This should be investigated by the Phase 2 team. The "contiguous" issue was never resolved by Phase 1 team. This issue can be addressed for unique cases through the exception process.

a. Are you aware of existing technical justification (i.e., analysis methodologies, completed studies, technical papers, etc.) that would assist the SDT in the development of technical justification for this issue? If so, please provide details in the 'Comments' field.

☐ Yes

☒ No

Comments:

4. Do you agree that the SDT should pursue technical justification for including in the BES definition the **equipment which "supports"** the reliable operation of the BES?

   ☐ Yes

   ☒ No

   Comments: This should be assigned to a different drafting team under a separate SAR. It should be limited to a simple and not a complex justification with an idea that BES support elements will only be required to comply with a smaller subset of reliability standards. This should not put undue burden of compliance for BES elements on the entities. Equipment that supports the reliable operation of the BES must be defined. "Support" must also be defined for its use in this context. Technical justification should analyze the facts, and then a determination made whether it does or does not support being included in the BES definition.

   The term "associated equipment" contained in the NERC Glossary of Terms Used In NERC Reliability Standards definition of "Transmission" either should be removed from that definition or should be separately defined. "Associated equipment" should be limited to a simple list of elements, such as relays and switches connected to BES feeders, and should not require use of a complex justification. The definition should be developed with the idea that BES support elements may only be required to comply with a subset of requirements specifically identified in applicable reliability standards. This definition should not put undue burden of compliance for BES elements on the entities. This is an alternate approach that supports the reliability language.

   a. Are you aware of existing technical justification (i.e. analysis methodologies, completed studies, technical papers, etc.) that would assist the SDT in the development of technical justification for this issue? If so, please provide details in the 'Comments' field.

   ☐ Yes

   ☒ No

   Comments:

5. Do you agree that the SDT should pursue technical justification to support including an automatic interrupting device in Exclusions E1 and E3?

☒ Yes

☐ No

Comments: Technical justification for this was not provided in Phase 1, and needs to be included in Phase 2. It should be addressed that an element which is excluded from the BES should be able to separate itself from the BES in the case of a fault on the non-BES element.

a. Are you aware of existing technical justification (i.e., analysis methodologies, completed studies, technical papers, etc.) that would assist the SDT in the development of technical justification for this issue? If so, please provide details in the 'Comments' field.

☐ Yes

☒ No

Comments: Discussed by the SDT in its Phase 1 deliberations. There is no existing technical justification available.

6. Do you agree that the SDT should pursue technical justification to support the inclusion of Cranking Paths in the BES definition and to retain Blackstart Resources as part of the BES definition?

☐ Yes

☒ No

Comments: Phase 2 should not undertake an examination of every attribute of the BES definition which has already been approved by the industry and the NERC Board of Trustees and filed with FERC. Blackstart requirements exist regardless if they are BES or not and are covered in the Reliability Standards. The SDT has already discussed the technical concepts in its Phase 1 deliberations. Refer to the response to Question1. Cranking paths are part of the restoration process, and do not affect the reliability of the BES.

a. Are you aware of existing technical justification (i.e., analysis methodologies, completed studies, technical papers, etc.) that would assist the SDT in the development of technical justification for this issue? If so, please provide details in the 'Comments' field.

☐ Yes

☒ No

Comments:

7. Do you agree that the SDT should pursue technical justification for selection of 100 kV as the bright-line voltage level?

   ☒ Yes

   ☐ No

   Comments: The 100 kV brightline is a fundamental, but technically unsupported, assumption in the BES definition. Technical justification for the 100 kV or some higher threshold, e.g. 200kV, should be developed in Phase 2. Elements "necessary," but operated below this technically justified threshold could still be brought into the BES Defintion under the Rules of Procedure (RoP) Exception Process.

   a. Are you aware of existing technical justification (i.e. analysis methodologies, completed studies, technical papers, etc.) that would assist the SDT in the development of technical justification for this issue? If so, please provide details in the 'Comments' field.

   ☐ Yes

   ☒ No

   Comments:

8. Do you agree that the SDT should pursue technical justification to support allowing power flow out of the local network under certain conditions and if so, what the maximum allowable flow should be?

   ☒ Yes

   ☐ No

   Comments:

   a. Are you aware of existing technical justification (i.e., analysis methodologies, completed studies, technical papers, etc.) that would assist the SDT in the development of technical justification for this issue? If so, please provide details in the 'Comments' field.

   ☐ Yes

   ☒ No

   Comments:

9. Do you have any other issues that require technical justification that you feel need to be added to the SAR? If so, please provide a detailed explanation of the issue and why it should be included.

   ☒ Yes

   ☐ No

   Comments: There needs to be a technical justification and a threshold for the inclusion of "dispersed power producing resources" (for example wind, and solar).

10. Do you have any other issues that are associated with improving the clarity of the definition created in Phase 1 that will assist the Registered Entity in the identification of BES Elements without altering the intent or scope of the definition? If so, please provide a detailed explanation of the issue and why it should be included.

    ☒ Yes

    ☐ No

    Comments: Refer to the responses to all the above questions.

    The SDT needs to develop a "BES Definition Application Guide" to ensure that the BES Definition is implemented consistently across the continent. The "BES Definition Application Guide" would be most helpful to industry if it included both one-line diagrams and explanations with examples for each inclusion and exclusion.

    Regarding specific clarifications for the Phase 1 Definition:

    - Exclusion E2 depends on whether contractual or regulatory "services are provided to the generating unit… or to the retail Load." The SDT should provide specific examples for E2 part (ii) in which facilities would or would not be excluded. Alternatively, condition (ii) could be deleted.
    - Both Exclusions E2 and E3 are flow-based exclusions and depend on analysis rather than system configuration. The assumptions and conditions for this analysis are dependent on the BES classification. Do these flow specifications apply to all critical system conditions, such as load, dispatch, transfers, and do they apply to both "normal"

and “post-contingency” conditions? If so, which contingencies need to be assessed for this analysis – for example, P0 through P7 events in TPL-001-2?

- Exclusion E1 needs to be reworded for clarification. Exclusion E1 is labeled “radial systems”. Is this intended to apply to a single transmission line from a substation bus to another substation (with no other connections of 100 kV or higher)? If there were a parallel transmission line from that same bus to that other substation would those lines not be considered “radial”? Are transmission line taps considered “radial systems”? Annotated one-line diagram examples would easily clarify this exclusion.
- Does the “Note” in Exclusion E1 that a “normally open switching device… does not affect this exclusion;” mean that the device should be considered not to exist (as if permanently open), or that the device status should be disregarded (do not assume it will be open)?
- Inclusion I4 depends on the term “connected at a common point”-- this needs to be defined or better explained. For example, is this considered to be the Collector Substation feeder connection low-voltage bus only, or also the high-voltage bus on the high side of the collector transformer at the Collector Substation? If it is the former, it will exclude all of the wind interconnections of all sizes presently in the northeast United States (feeder voltages can be 34.5 kV for wind farms of hundreds of MW capacity).

11. Are you aware of any regional variances associated with approved NERC Reliability Standards that will be needed as a result of this project? If yes, please identify the Regional Variance.

☐ Yes

☒ No

Comments: As this project moves forward there may be issues that to be resolved will require regional variances. At that time industry must be given the opportunity to provide comments.

12. Are you aware of any business practice that will be needed or that will need to be modified as a result of this project? If yes, please identify the business practice:

☐ Yes

☒ No

Comments:

13. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

Comments: The primary goal of Phase 2 must be to develop guidance for the new BES Definition. Any technical justification efforts should not detract from the guidance effort and must be consistent with the FERC Orders on the BES Definition. There is a risk that technical analyses to justify inclusions and exclusions of elements in the BES Definition may be generalized to a larger set of conditions, when the analyses apply only to a set of specific situations or system conditions. System behavior depends on many factors, many of which are not standardized for the entire industry.

An item that should be added to the SAR project and addressed is the necessity to define what is meant by the phrase "necessary for the reliable operation of the interconnected transmission network". Some discussion to establish a reliability matrix must precede other discussions concerning items included in the SAR. If the vast majority of Elements are indeed useful to reliability, not all should be considered as necessary. Stability, reliability and grid integrity issues have to be distinguished from service continuity issues. Elements that contribute to the reliability of the BES have to be distinguished from those that contribute to the reliability of local load (service continuity). Referring to NERC's Reliability Principles, Reliability Objectives (draft), or to the Concept of Adequate Level of Reliability are resources that would be helpful.

The analyses used to make technical justifications to be considered by the Drafting Team in potential revision of the Standard should be pub,ished and be made available to the stakeholders for review.

The subject matter expertise must be made available by either expanding the Drafting Team or through delegation of technical study to the appropriate NERC groups or other existing Drafting Teams. The Standards Committee could commission another Drafting Team as

necessary for portions of the work, and the Drafting Team assign a “sub-team” as well, a RFP could be issued. Suggest that the Operating and Planning Committees be engaged as necessary during the comment periods to provide specialized subject matter expertise.

There is concern regarding the coordination of the timing of the implementation of Phases 1 and 2.

The BES Definition Application Guide mentioned in the response to Question 10 that should be developed should be presented to industry for review and comment, and the consideration to have it balloted should be weighed. It would be needed by industry before Phase 2, in any format, is balloted.

From:	Goodman, Kathleen
To:	rscmembers
Subject:	FW: comments submitted on the RC Standards set.
Date:	Wednesday, February 08, 2012 2:37:09 PM

FYI

_____

From: Goodman, Kathleen
Sent: Wednesday, February 08, 2012 2:33 PM
To: SRC@misoenergy.org
Subject: comments submitted on the RC Standards set.

Top of Form

Comment Form: Project 2006-06 Reliability Coordination

IMPORTANT NOTE: *Please make sure to hit the FINISH button at the bottom of this screen to submit your comments to NERC. A verification code will be provided on the next screen.

Survey Response: Comment Form: Project 2006-06 Reliability Coordination
Comment Request - Project 2006-06 First Formal Posting Reliability Coordination
Response GUID: a6ae8875-37dd-4840-9e87-4a9ad14e51d1
Started: 2/8/2012 2:18:07 PM
Completed: 2/8/2012 2:32:31 PM

Page 2

1) **Individual or group.**
Individual

Page 3

2) **Name**
Kathleen Goodman

3) **Organization**
ISO New England

4) **Telephone**
###-###-####
413-535-4111

5) **E-mail**
kgoodman@iso-ne.com

6) **NERC Region (check all Regions in which your company operates)**
NPCC

7) **Registered Ballot body segment (check all industry segments in which your company is registered)**

2 - RTOs and ISOs

Page 5

8) **Question 1**

1. The RCSDT has revised the applicability of the standards and implementation plans by aligning COM-001-2, COM-002-3, and IRO-001-2 to apply to the same entities and by removing LSE, PSE and TSP as applicable entities from the COM standards. Additionally, the Interchange Coordinator has been removed as an applicable entity from the standards. Do you agree with this change in applicability to the three standards? If not, please explain in the comment area below.

Yes

Page 6

9) **Question 2**

2. Do you agree with the addition of “Adjacent” entities in COM-001-2, Parts 3.5, 4.3, 5.5 and 6.3 of COM-001-2? If not, please explain in the comment area below.

No

10) **Question 2 Comments:**

ISO-NE does not believe COM-001, in its entirety, is a results-based standards and therefore does not support the draft as written. We believe such "requirements" (i.e. capabilities) should be verified through an entity certification process.

Additionally, results-based requirements should be the driver to have the capability to achieve them; on other words, there is no other way to reliably dispatch than to have communications facilities (electronic or voice).

Page 7

11) **Question 3**

3. The RCSDT removed the phrase "to exchange Interconnection and operating information" in COM-001-2, Requirements R1 through R8 based on stakeholder comments. Do you agree with the revision? If not, please explain in the comment area below.

No

12) **Question 3 Comments:**

ISO-NE does not believe COM-001, in its entirety, is a results-based standards and therefore does not support the draft as written. We believe such "requirements" (i.e. capabilities) should be verified through an entity certification process.

Additionally, results-based requirements should be the driver to have the capability to achieve them; on other words, there is no other way to reliably dispatch than to have communications facilities (electronic or voice).

Page 8

13) **Question 4**

4. A new requirement was added for clarity regarding what is required of Distribution Providers and the Generator Operators: R11. Each Distribution Provider and Generator Operator that experiences a failure of any of its Interpersonal Communication capabilities shall consult with their Transmission Operator or Balancing Authority as applicable to determine a mutually agreeable time to restore the Interpersonal Communication

capability. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations] This requirement requires collaboration between entities to restore a failed communications capability. Do you agree with the new requirement? If not, please explain in the comment area below.

No

14) **Question 4 Comments:**

ISO-NE does not believe COM-001, in its entirety, is a results-based standards and therefore does not support the draft as written. We believe such "requirements" (i.e. capabilities) should be verified through an entity certification process.

Additionally, results-based requirements should be the driver to have the capability to achieve them; on other words, there is no other way to reliably dispatch than to have communications facilities (electronic or voice).

Page 9

15) **Question 5**

5. The proposed definition of Reliability Directive shown in COM-002-3 was revised to include Adverse Reliability Impact as shown to more fully address emergencies or events that might lead to instability or Cascading: Reliability Directive: A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impact. Do you agree with the proposed definition? If not, please explain in the comment area below.

Yes

Page 10

16) **Question 6 Comments:**

none

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Bottom of Form

Kathleen Goodman

Senior Operations Compliance Coordinator

(413) 535-4111

kgoodman@iso-ne.com

Unofficial Comment Form

Reliability Coordination (Project 2006-06)

Please **DO NOT** use this form to submit comments. Please use the electronic comment form to submit comments on the first formal posting for Project 2006-06—Reliability Coordination. The electronic comment form must be completed by **February 8, 2011.**

2006-06 Project Page

If you have questions please contact Stephen Crutchfield at stephen.crutchfield@nerc.net or by telephone at 609-651-9455.

Background

The RCSDT has revised the COM-001-2, COM-002-3 and IRO-001-1 standards based on stakeholder comments received during the initial ballot and formal comment period and quality reviews of each standard.

The RCSDT has addressed comments on the applicability of all three standards and implementation plans by aligning COM-001-2, COM-002-3, and IRO-001-2 to apply to the same entities and by removing LSE, PSE and TSP as applicable entities from the COM standards. Additionally, the Interchange Coordinator has been removed as an applicable entity from the standards and implementation plans.

Several commenters had suggestions for improvements to the requirement language and applicability of COM-001-2. The RCSDT believes the standard correctly and adequately requires each applicable entity that would have capability to receive Interconnection and operating information to have Interpersonal Communications, and Alternative Interpersonal Communications to be used when the Interpersonal Communication is not available. The RCSDT made the following changes to COM-001-2 based on stakeholder suggestions:

1. The following Requirement parts were added to COM-001-2:
   - 3.5 Adjacent Transmission Operators synchronously connected within the same Interconnection
   - 4.3 Adjacent Transmission Operators synchronously connected within the same Interconnection
   - 5.5 Adjacent Balancing Authorities
   - 6.3 Adjacent Balancing Authorities
2. The phrase "to exchange Interconnection and operating information" was removed from requirements R1 through R8 to clarify that the intent of this capability is NOT for the exchange of data.
3. A new requirement was added for clarity regarding what is required of Distribution Providers and Generator Operators (i.e., collaboration between entities to restore a failed communications capability):

   R11. Each Distribution Provider and Generator Operator that experiences a failure of any of its Interpersonal Communication capabilities shall consult with their Transmission Operator or Balancing Authority as applicable to determine a mutually agreeable time to

restore the Interpersonal Communication capability. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations]

The proposed definition of Reliability Directive shown in COM-002-3 was revised to include Adverse Reliability Impact as shown to more fully address emergencies or events that might lead to instability or Cascading:

Reliability Directive: A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impact.

As a reference, we have included the existing definition of Emergency and the BOT approved definition of Adverse Reliability Impact[1]:

Emergency: Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.

Adverse Reliability Impact: The impact of an event that results in Bulk Electric System instability or Cascading.

Based on stakeholder feedback regarding IRO-001, the RCSDT removed Requirement R1. Other requirements were removed from IRO-001 and placed in more appropriate standards. These requirements did not fit with the purpose statement of IRO-001. Requirements R5 and R6 were removed from IRO-001 and placed in IRO-005-4. Requirements R7 and R8 were removed from IRO-001 and placed in IRO-002-2. These requirements were balloted and approved by stakeholders in July of 2011 and subsequently approved by the NERC BOT on August 4, 2011.

In addition, minor clarifications were made to the language of requirements and measures in COM-002-3 and IRO-001-3 based on suggestions from quality reviews of those standards.

[1] This definition was approved by the NERC Board of Trustees on August 4, 2011. Filing with regulatory authorities is pending.

You do not have to answer all questions. Enter all comments in Simple Text Format.

1. The RCSDT has revised the applicability of the standards and implementation plans by aligning COM-001-2, COM-002-3, and IRO-001-2 to apply to the same entities and by removing LSE, PSE and TSP as applicable entities from the COM standards. Additionally, the Interchange Coordinator has been removed as an applicable entity from the standards. Do you agree with this change in applicability to the three standards? If not, please explain in the comment area below.

☐ Yes

☐ No

Comments:

2. Do you agree with the addition of "Adjacent" entities in COM-001-2, Parts 3.5, 4.3, 5.5 and 6.3 of COM-001-2? If not, please explain in the comment area below

☐ Yes

☒ No

Comments: NERC uses the terms "adjacent" and "neighboring" in various standards. It is generally believed that those terms have the same meanings, but there are those who believe those terms, as used, are intended to have different meanings. To ensure a consistent usage and understanding, the definition of the term adjacent must be made known before its addition to the standard. Consideration should be given to using only one term in all standards if adjacent and neighboring are intended to mean the same thing. Both terms are used in NERC Standards, sometimes both in the same standard. For example, EOP-001-2b uses "neighboring" in R5, and "adjacent" in R3.3.

3. The RCSDT removed the phrase "to exchange Interconnection and operating information" in COM-001-2, Requirements R1 through R8 based on stakeholder comments. Do you agree with the revision? If not, please explain in the comment area below.

☐ Yes

☐ No

Comments:

4. A new requirement was added for clarity regarding what is required of Distribution Providers and the Generator Operators:

R11. Each Distribution Provider and Generator Operator that experiences a failure of any of its Interpersonal Communication capabilities shall consult with their Transmission Operator or Balancing Authority as applicable to determine a mutually agreeable time to restore the

Interpersonal Communication capability. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations]

This requirement requires collaboration between entities to restore a failed communications capability. Do you agree with the new requirement? If not, please explain in the comment area below

☐ Yes
☐ No
Comments:

5. The proposed definition of Reliability Directive shown in COM-002-3 was revised to include Adverse Reliability Impact as shown to more fully address emergencies or events that might lead to instability or Cascading:

Reliability Directive: A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impact.

Do you agree with the proposed definition? If not, please explain in the comment area below

☐ Yes
☐ No
Comments:

6. Do you have any other comment, not expressed in questions above, for the RC SDT?

Comments: For COM-001:
1. R1.2 and R2.2: The phrase "within the same Interconnection" is improper; it needs to be removed. RCs between two Interconnections still need to communicate with each other for reliability coordination (e.g. between Quebec and the other RCs in the NPCC region to coordinate reliability issues including curtailing interchange transactions crossing an Interconnection boundary). The SDT's response to industry comments on the previous posting that the phrase was added to address the ERCOT situation (that ERCOT does not need to communicate with other RCs and that such coordination takes place between TOPs) leaves a reliability gap.

2. R3.5 and R4.3: The phrase "synchronously connected within the same Interconnection" is also improper; it needs to be removed. TOPs do communicate with other TOPs including those asynchronously connected and in another Interconnection (e.g. between Quebec and all of its asynchronously interconnected neighbors). The reason that was used in response to the above comments (coordination among TOPs for DC tie operation) contradicts with the inclusion of this phrase in R3.5 and R4.3.

3. R4 and R6: Not requiring an Alternative Interpersonal Communication capability between the BAs and the DP and GOP can result in a reliability gap. If Interpersonal Communication capability between

the BAs and these entities is required to begin with to enable BAs to communicate with these entities (such as operating instructions or Reliability Directives) to ensure reliable operations, then an alternative capability is also needed to ensure this objective is achieved when the primary capability fails.

4. To preclude the possibility of problems arising from having different languages spoken between entities, COM-001-1.1 R4 should remain as it was or those ideas kept in the revised requirement. R4 read:

"R4. Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations."

5. Measure M3 does not cover the added R3.5 condition (having Interpersonal Communications capability with each adjacent TOP). M3 needs to be revised.

For IRO-001:

The Data Retention Section does not reflect the revised requirements. As examples: the Electric Reliability Organization is no longer a responsible entity; the Reliability Coordinator should replace the ERO for keeping data for R1. Transmission Operator, Balancing Authority, Generator Operator and Distribution Provider should replace the Reliability Coordinator for keeping data for R2. And, in the Data Retention Section, R4 and M4 are mentioned. However, there are only three requirements with their corresponding measures in the standard.

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - Project 2006-06 Reliability Coordination | Three Ballot Windows Extended, Three Non-binding poll Windows Extended One Day | Formal Comment Period Extended One Day
Date: Thursday, February 09, 2012 10:44:14 AM

Standards Announcement

Project 2006-06 Reliability Coordination

Three Ballot Windows Extended, Three Non-binding poll Windows Extended One Day
Formal Comment Period Extended One Day
Through 8 p.m. Eastern TODAY (Thursday, February 9, 2012)

Now Available

Three non-binding polls of the VRFs and VSLs associated with the standards listed below failed to achieve a quorum and have been extended by one day. In addition, to accommodate ballot pool members and other stakeholders affected by a brief unavailability of NERC web services at the end of the ballot and comment period window, the formal comment period and three ballots of these standards and their associated implementation plans will also be extended one day. The non-binding polls, ballots, and formal comment period will close at **8 p.m. Eastern TODAY, Thursday, February 9, 2012**.

- COM-001-2 – Communications
- COM-002-3 – Communication and Coordination
- IRO-001-3 – Reliability Coordination – Responsibilities and Authorities

Please log in and cast your ballots for these standards, and opinions in the non-binding polls, if you have not already done so.

Standards Development Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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

You have received this email because you are a registered representative in the Registered Ballot Body.

From: Guy V. Zito
To: rsc; tfsp; tfco-all; tfss; tfcp
Cc: Andy.Rodriquez@nerc.net
Subject: Current NERC Standard Drafting Team Openings.
Date: Tuesday, January 03, 2012 10:55:58 AM
Attachments: DT_Nomination_Form_2009Feb03.doc
Importance: High

RSC Members et al,

The following standard drafting team openings exist and NERC is soliciting the below:

Project 2007-06 System Protection Coordination	Seeking an individual from a Canadian entity.	Experience in: • Coordination of protection systems (new installations and revisions.
Project 2007-12 Frequency Response	Seeking an individual representing Transmission Dependent Utilities.	Experience in analyzing or modeling frequency response.
Project 2010-07 Generator Requirements at the Transmission Interface	Seeking an individual who is currently a NERC-certified System Operator, preferable as a Transmission Operator or Reliability Coordinator.	The candidate should also be familiar with the history of the GOTO Ad Hoc Group, recent registration activity, and the work of the Project 2010-07 SDT.

If interested, please fill out the attached self-nomination form and return to andy.rodriquez@nerc.net , and CC: me.

Thanks and Happy New Year to all.

Guy V. Zito
Asst. Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Nomination Form for [Name] SAR or Standard Drafting Team (Project Number)

Please return this form by **[Date].** If you have any questions, please contact [Name of Coordinator] at [E-mail of Coordinator] or by telephone at [phone # of Coordinator].

All candidates should be prepared to participate actively at drafting team meetings.

Name: Organization: Address: Office Telephone: E-mail:
Please briefly describe your experience and qualifications to serve on the [Name of SAR or Standard] Drafting Team. Prefer experience in [identify areas of desired experience].
If you are currently a member of any NERC SAR or standard drafting team, please list each team here. ☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following SAR or standard drafting team(s):
If you previously worked on any SAR or standard drafting team please identify the team(s). ☐ No prior NERC SAR or standard drafting team experience. ☐ Prior experience on the following team(s):

Select each NERC Region that you represent:	Select each Industry Segment that you represent:	
☐ ERCOT ☐ FRCC ☐ MRO ☐ NPCC ☐ RFC ☐ SERC ☐ SPP ☐ WECC ☐ NA – Not Applicable	☐	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, and Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities
	☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:

☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.

Name:	Office Telephone:
Organization:	E-mail:
Name:	Office Telephone:
Organization:	E-mail:

[1] These functions are defined in the NERC Functional Model, which is downloadable from the NERC Web site.

December 13, 2011 | 1–5 p.m. (EST)
December 14, 2011 | 8 a.m.–noon (EST)

Westin Buckhead Atlanta
3391 Peachtree Road NE
Atlanta, GA 30326
(404) 365-0064

Administrative

a. Welcome and Introductions – Tom Bowe, PJM OP and PC together in Joint Session – opportunity to present arguments and discussions at same time to both committees – motions for approval will need to be done separately. Moved joint OC/PC approval items presentations first.
b. NERC Antitrust Guidelines – Mark L.
c. Notice of Public Meeting – Mark L.
d. Parliamentary Procedures – In Agenda package.
e. Announcement of Quorum **– OC Quorum and PC Quorum achieved.**

Agenda

1. **Remarks by NERC President and CEO, Gerry Cauley**

Welcome to Atlanta
Focus on where NERC is heading – expertise of industry is a key part
Four keys to success:

- ✓ Reliability – are we solving reliability problems/improving reliability
- ✓ Risk Based approach – biggest bang for the buck
- ✓ Learning as an industry/opportunities to improve/don't repeat errors
- ✓ Accountability – to the Public/FERC/Regulators/Industry – show that we accomplished something

Priorities:

- ✓ Relay mis-operations
- ✓ Field Errors
- ✓ Unknown Risks – cyber security/GMD

Dynamic world that we live in – major cold weather event in TX – event touched all the bases – reliability, risk, learning – Industry can identify where the risks lie, and what can we do to prevent them. Technical Committees focus on the technical issues – help us prevent the next big event.
Tool set:

- ✓ Standards
- ✓ Training
- ✓ Lessons Learned

Alignment of the ERO – coordination of programs.
Priority with the NERC BOT is to engage in the Committees – identify what are the reliability initiatives underway, and give the BOT an opportunity to share their insight.

Tom Bowe – encourage the OC and PC to consider these points when carrying out their respective Strategic Plans.

First:
f. Review of Integrated Reliability Index Proposal – David Robinson, Sandia National Laboratories – gave presentation (to be provided).

No questions or discussion.

3. Joint Committee Actions

a. Vote for Approval
i. Phased Development of Integrated Reliability Indicators (IRIs) – Bill Adams, Georgia Power (presentation in the Agenda Package)

Discussion:
Q: Single index (MW hours lost) – or some combinations of separate metrics? Think the former is better than the later – has more customer focus.
A: The IRI proposed would be a combination of metrics.

Motion – Approve Phased Development of Integrated Reliability Indicators
OC – moved and seconded.
Approved
PC – moved and seconded.
Approved

Further Discussion – none.

ii. Performance Analysis Subcommittee (PAS) Scope – Bill Adams, Georgia Power (presentation in the Agenda package)

Discussion:
Q: RMWG collapsing into this subcommittee – will emphasis on metrics be lost?
A: No, we talked about this - all existing RMWG members are asked to be part of the PAS.

Q: So many events are operational related, shouldn't the PAS report to the OC?

A: Doesn't matter since, both groups would be involved – it's on both Strategic plans.

Q: Seems way too much for normal humans to address – what are the priorities?
A: Biggest challenge is coming up with the right structure. 18 approved metrics now, don't think people want more – working on the risk based metrics now.

Q: Looking at the scope – identify areas of future reliability risks – different than the LTRA emerging issues? Overlap?
A Different – issues identified through the annual reliability report.

Motion - Approve the PAS Scope
PC – moved and seconded.
Approved
OC – moved and seconded.
Approved

Further Discussion:
Q: Asking for approval of the scope or the approval of the subcommittee?
A: By approving the scope, the subcommittee follows.

Friendly amendment – approve scope as well as creation of the subcommittee itself?
Jeff M. – FYI - the PC has already approved the creation of the PAS.
A: To make it simple, would like to have the same motion.

Q: does this disband the RMWG?
A: Let's handle that separately.

iii. Event Analysis Working Group (EAWG) - for Board consideration, final Event Analysis process

Bill A. - Some may have issues with the associated RoP changes – comment on that by December 21st – just talking here about the EAWG product.

Electric Reliability Organization Event Analysis (EA) Process – Jacquie Smith (presentation in the Agenda package)

Discussion:
Q: Is this different that what the Standard Drafting Team (SDT) is recommending?.
A: This is taking a parallel path from that of the SDT – we think our document is a living document – we would change ours as the reporting requirements evolve.

Q: Path forward for the EA process – to be presented to the BOT – as a mandatory program?
A: Concerns about taking something in the spirit of learning from the analysis conducted – your question is more about the RoP process.

Q: If you vote against approval of this approach (and we applaud all the work being done) because the EOP4 language doesn't match right now, and the RoP is under discussion – shouldn't all components should be presented to the BOT in order to understand how it will all work together? Shouldn't take much longer to provide the BOT with a coordinated package.
A: Currently posed revised RoP 807, 808, key principals of the EA process in those documents; the entire document will be in Appendix 8 – the entire EA document will not be in the RoP – it would be too cumbersome. The key principals behind the program are in their – the EA document will be easily revised.

Q: Who would initiate a revision of the EA document?
A: The EAWG would bring revisions to the OC – Event trending subcommittee (instead of EA) would be the keeper of that document.

Earl S. Feel this is an ERO document – but revision would be done through the Committee process.

Q: Seems to be a lot of 'shalls' in the document – for a cooperative, voluntary process.
A: Tried to clearly spell out roles and responsibilities in Appendix H; idea has always been that the best entity to do EA is the one involved in the event; understand there are also oversight roles, as shown by the matrix (i.e., the role of the Regional Entities).

Q: But what if some entities don't have the skill sets to do such an analysis?
A: We would disagree – the document clarifies that if the entity does not have the resources to carry out an analysis, the Region will step in to help.

Motion: Approve the Event Analysis process
OC
Moved and Seconded
Reported Not Approved (close vote) – BUT corrected at the OC meeting the next day – review of the vote indicated it DID pass.
PC
Moved and Seconded
Approved

Further OC Discussion:
Everyone has concerns on EA RoP – everyone wants lessons learned, but there is a better way to go about it.

Think this is the framework of what could be there, but reads like a compliance document.
A few things need to be looked at more closely.

The closer you are to the work, the better your results - when people are engaged directly, they have better chance of a quality product.

Q: Contributory factors – is this something expected to be filled out?
A: Tools for an entity to use for EA – to help an entity step through the process.

Timelines – allows the RE and NERC to adjust the deadlines and timelines as necessary – they can be further refined. Working on our own procedure at WECC – as a supporting document to the NERC approach.

Looking at trends and factors, project where to focus industry attention on it, with the tools it needs.

2. Joint Session (OC/PC) Information Items

a. Compliance Application Notices – Mike Moon, NERC

i. Focused on specific technical issues and potential boundaries of acceptable compliance
Want more OC/PC input to help use frame the issues to get reasonable boundaries.

b. NERC Events Analysis Update "Drift Concept" – Earl Shockley, NERC

c. Adequate Level of Reliability Task Force – Mike M. – it's at an earlier stage, know it's hard to comment at this time.

It's time to start thinking more critically what reliability means.
Who is the target audience for ALR – customer, regulator, industry? – the ALR could be different. Think the audience is the ultimate customers, our obligation to serve.

Q: The customer/FERC/the regulator/NERC/Industry should know (when we are done) and fully understand the difference between adequacy and adequate level – how do you address resource adequacy in the ALR? (i.e., an area that NERC does not have responsibility/mandate for)?
A: Leave it out if NERC/FERC doesn't have a defined role.

Q: How do you bring in the cost/benefits?
A: Will attempt to do that – struggling with commonality of terms now – just not there yet.

Mark Kuras – we at RAS talk all the time about Resource Adequacy issues – invite you to come talk to us about this.

Need to align ALR with the NERC Functional model – ALR for a Generator/ ALR for a TO … etc.

Hope this gives the ALR Task Force some insight.

d. Review of Geomagnetic Disturbance Task Force Report – Don Watkins, BPA (presentation in Agenda package)

Topic getting lots of attention at the White house/DOE – make sure you review it so it says what you want.

Q: Chapter 10 viewpoint – seems to give a mixed view
A: Took the best information we could from the two views of transformer failure – tried to obtain a synthesis the two views together – yes, there is some substantial vulnerability to some transformer banks, but others could weather the event very well. Want to determine some process to screen the transformer banks to see whether or not a more detailed analysis is needed – a group is working on this.

Q: Do you plan for GIC from GMD's into your system, and include requirements into your transformer specifications?
A: The asset owners are responsible – they rely on IEEE Standards to help them do their risk analysis – absent any additional NERC requirements, you would be making this difficult for them to address.

Q: Who owns the recommendation?
A: It pretty broadly worded now – NERC does, but some responsibility would fall under the OC, some under the PC.

Q: An RTO would have comprehensive procedures around a GMD event – the challenge is, we are not clear on the equipment impact of these events – how a 200 amp GIC impact on a transformer impacts the overall performance of the equipment, for instance.
A: Need to have the processes and procedures in place way in advance of an event, in order to react to the accrual occurrences.

e. **Review of Severe Impact Resilience Task Force Draft Report – Tom Bowe, PJM**
i. Comments on Draft Report Due by January 4, 2012
Look at Appendix 4 – the up-front recommendations – check out one Chapter of your interest – would like to make dent

3:00 – 3:30 PM BREAK

PC Meeting

4. **Administrative**

a. Welcome and Introductions – Chair Jeff Mitchell

b. Future Meetings – Secretary John Moura
i. March 6-7, 2012 – Phoenix, AZ (confirmed)
ii. June 19-20, 2012 – Toronto, Canada
iii. September 17-20, 2012 – St. Louis, MO
December 11-12, 2012 - Atlanta

i. Planning Committee Membership (2011 – 2013)
PC open positions: Electricity Marketer (1), Large End Use User (2)

d. Arrangements– John Moura tomorrow - 8:00 am start.

e. Agenda Approval – Chair Jeff Mitchell
Three changes:

- ✓ 8(a) - Alison Silverstein will present a NASPI Update.
- ✓ 9a(iii)b - Comments are due December 30th for the proposed RADWG – PC to consider approval in February 2012 by conference call or at the March 2012 PC meeting
- ✓ 10d RAS – EPA Phase II Scope – Anticipate December 16th EPA Final Rule – Discussion only for PC today – Approval at March PC Meeting.

Agenda Approved as changed.

5. **Consent Agenda**

a. **Approved** – Draft Meeting Minutes as final – Secretary John Moura
i. PC_Draft_Meeting_Minutes_St Louis September 13-14_2011
ii. PC Draft Conference Call Minutes October 25, 2011
iii. PC Draft Conference Call Minutes November 14, 2011

6. **Chairman's Remarks** – Chair Mitchell

a. NERC's Board and Member Representatives Committee meetings – no report.

b. PC Executive Committee Discussion

Jeff M. reported – at this morning's EXCOM meeting:

- ✓ Phase 2 BES "technical justification" what is necessary to reliably operate the power system.
  - Gen threshold/contiguous/voltage level
  - Don't want to foist any assignments off to a PC subcommittee;
  - Steering committee/EXCOM may be involved in this – PC represented on the DT – Jeff M./Phil F./Jonathan S. – coming in March 2012
- ✓ GMD TF report – need for PC involvement in the review process
- ✓ FERC 754 – TIS a/k/a SAMS – work progressing
- ✓ Joint OC/PC meeting – PC responsible for next year's March joint OC/PC/CIPC meeting (will probably be a webinar)
- ✓ How to get more PC Members involved in what we do here – OC approach – instead of everyone reviewing all reports/ have teams review reports, and report back to the PC
- ✓ Will try for the GMD TF report – get some SME PC (up to five) – give a quick likes/dislikes review to the full PC – then maybe consider approach for seasonal assessments/special assessments – anyone can review and comment, but this may get more PC involvement overall. For the GMD TF report – any volunteers?
  - Dave Weaver – make sure it's a cross sector make-up; also consider if the PC rep's company is heavily involved in the analysis.
  - Dale B. – I'm not a SME, but someone in my company is, would be glad to come back to bring our perspective.
  - Jason – put my name down.
- ✓ Quick breakfast with the OC leadership/ and will probably have a quick debriefing following the meeting.
- ✓ How did the joint OC/PC meeting go?
  - Jason – audio was hard to hear
  - Tom – thought it was good that the presenters had to provide comments once – separate room for the OC/PC in one grouping
  - Dave B. – great opportunity
  - Phil F. – double U table set-up to allow closer proximity/interaction of respective OC/PC representatives
  - Mark K. – what if you get a motion in one Committee and not the other – logistics need to be worked out.
  - John Moura – who goes first (OC or PC), may influence the outcome.
  - Nano – mix OC/PC representatives all together, then go off for a separate vote.

c. Future Committee Activities – no report

7. Committee Matters

a. **Review** - Committee work plan for 2012 – Chair Mitchell/Mark Lauby
Mark L. reviews the deliverables from the TF & Working Groups – will send out a spreadsheet so PC representatives can weigh in on this item or that item.

2012 RAS Products

- ✓ LTRA
- ✓ Summer/Winter Assessment
- ✓ Post Seasonal
- ✓ Special reliability Assessment
- ✓ Gas/Electric Interdependency
- ✓ EPA Phase III Study
- ✓ probA

2012 SPCS Products

- ✓ SPS Definition and related Standards
- ✓ Response of relays to power Swings
- ✓ Analysis of Mis-operations

2012 SAMS/MVTF Products

- ✓ MV Technical reference and Guidelines
- ✓ Modeling Standards review and SARS
- ✓ Turbine control
- ✓ FIDVR Analysis protection
- ✓ Frequency response report

Mark L. - Ask for PC volunteers to review products and
Phil F. – Suggest PC representatives send Mark L. the top three or four areas they feel they would by comfortable for being the SME/reviewer.

8. Information Only Items

b. ERO-RAPA Modeling Initiative – Joe Spencer, SERC (ERO-RAPA Chair)
Eastern Interconnection Modeling Effort (presentation to be provided to the PC following the meeting)

Timeline to gather better data -Middle of the year
Bob C. – drafting survey on outer loop controls – launch in March – tie-in with the ERAG MC

Dale B. – does base level = initial projection (legacy); what's it supposed to look like?
Eric A.– should look like the best generic (blue August 7-8 l/o 4,800 MW) Sat afternoon in August represents a 20 squelched 10 fully responsive modeling assumption.

Q: Then if we need a better model – and comes from a request to generator owners – what happens if we don't get it?
Nano – how do we know if we get the appropriate data from the responsible person – we can ask, but how do we know?
Bob C – modeling work always falls to the most inexperienced person - will have to apply the laugh test to the data received – required to get it via the MOD Standards.

Phil F. – recognize the results are true for the large scale loss of source simulated (l/o 4,800 MW of generation), and run out to 60 seconds – the models may be just find for loss of single generator units, loss of load, critical clearing studies, and other 'transient' applications. How much more accuracy do you expect to gain by asking for more detailed modeling in the survey, more than what the experimentally determined models presented?

Bob C. – yes, these recommendations would be applicable to UFLS islanding studies, or other large scale loss of generation resulting in a large drop of frequency. (58.5 Hz or more) May be other control modes that override governor action in this time period. Wouldn't believe any study using existing governor representation for UFLS or islanding studies.

c. Order 754 Project – Scott Barfield, NERC (presentation provide to PC at meeting)

a. NASPI Synchro-phasor presentation – Alison Silverstein, NASPI (provided in Agenda package)
Q: Could you model/monitor GMD events with this?
A: Was discussed earlier with DOE but wasn't followed through – it should be possible.

John M. - Uses satellites for GPS time synchronization – may not be able to be reliable enough if satellite communications is lost due to GMD events.
A: More important to identify whether or not the data being received is true – then figure out when to resynchronize the time signals once a disturbance passes.

Q: Your sweet spot – 3 to 5 years – is the same sweet spot for the planning horizon – how does this integration impact the planning process?
A: Trying to send success stories and liaison with you – the more you tell us what you need, the more we can tailor what we can provide.

END – 5:21 pm
START – 8:00 am December 14, 2011

9. Committee Actions

a. Subcommittee and Working Group Scope Approvals

a) Performance Analysis Subcommittee
Approved

i. Demand Response Availability Data System Working Group (DADSWG)
Approved

ii. Generating Availability Data System Working Group (GADSWG)
Approved

iii. Transmission Availability Data System Working Group (TADSWG)
Brian Keel – whether or not to continue with TADS – should that be part of the scope (Phase II – non-automatic outage data sunset)
Q: First year of five years of data in 2010 – there is an automatic five year sunset provision, unless overridden.

Nano - Transformers high side or low side at 100 kV? San Diego event had some 94kV transformers involved.
A: - 100kV low-side. Current proposal asking comments on this – covered in the letter asking for comments. Premature to put in the scope at this time.

Approved

b) System Analysis and Modeling Subcommittee
Dale B. – What's going on with this – previously MVTF reported to TIS?
A: SAMS is the new TIS (slightly revised). This gives SAMS a little more depth to do what they need to do.

Ron M. – Activity 9 – analyzing system events – wouldn't this be events analysis?
A: This is doing the modeling for events, certain events that NERC is involved with.

Approved

i. Model Validation Working Group
Approved

c) Reliability Assessments Subcommittee
Q: Didn't see an Order of Business as in the other subcommittee Scopes - Look at TADS, for instance.
John Moura – will add in.

Ron M. – do they need to have this because they don't have the same sector structure as the PC?
John M. - ultimately the voting doesn't occur at the subcommittee

Ron M. – then you should put them in all of them - PAS scope had an "Order of Business" section.

Approved – (with an "Order of Business" section added)

Q: What about the other subcommittees that don't have it. (i.e, "Order of Business" section)

Paul K. – let NERC staff review the scopes for consistency, and put it on the consent agenda next meeting.
Dan R. - SAMS or MVTF scopes don't have it.

Agreed

i. Reliability Assessment Data Working Group (pulled from Agenda - the RADWG Scope – to be considered in February/March)
Q: Comments today?
A: due December 30th.

Kevin - SERC staff has some comments and will be submitting them.

d) System Protection and Control Subcommittee (SPCS) Scope

Jonathan S. – create bullets for the items under number 3 – we don't have an Order of Business either.

Paul Kure – the Subgroups have words in its Membership Section "…will follow the voting rights of the PC …" that's why they don't have an Order of Business section.

Approved – (with changes noted)

10. Subcommittee Reports

a. TADS Working– Request for Public Comment on the Transmission Availability Data System - Proposed 100-199kV Automatic Outage Data Collection - Chair Jake Langthorn (presentation in Agenda package)

In 2014, will institute Phase II

Q: Why aren't you asking them what is the cost to the TO's to supply this information?
A: What would we do with the cost information if we get it – a distinct desire from all parts of the industry to get this additional outage information. If you want to include cost estimates, make it part of your motion.

Q: Why do a 1600 data request?
A: All data requests are covered by Section 1600.

Jonathan S. – what are you waiting for regarding radial circuits?
A: At this point in time, we want the BES definition for radial circuit, not our own. EIA extremely interested in this information. This is a proposal to ask industry if they think its necessary – the BES definition is key, if not finalized, it would put this work off until to 2014.

David Weaver – once a clear radial definition is given for the requested 100-200 kV data – radial is excluded – but it doesn't say anything above 200kV.
A: Since the new BES isn't defined yet, this gives us the flexibility to move forward.
Questionnaire goes out – historically only 25% answer.

Q: Approve request for public comment, with addition of cost estimates to supply the data?
Jeff M. – may not be in our authority to do so. Haven't done this before – don't feel comfortable doing this on the second part of a data request that didn't ask for cost on the first part (or any other 1600 data request)

Alternate suggestion – rather than costs, how about asking for a time estimate to provide the data?
Jeff M. – still uncomfortable with it.
John Moura – how would do you do a cost benefit analysis, assuming you could get the data?

Ken – Just because it hasn't been done before, doesn't mean we shouldn't do it. We are constantly being asked about what are the benefits – NERC should take it up – not so much NERC's cost, what about our costs – our regulators question our costs of coming to these meetings.

Mark L. – maybe we need to get a group together to look at costs. Need a consistent way to assess.

David Weaver – we put a lot of resources around audits – it's the need to do it for this data request. We are already doing it 200kV and above (it was mandated, we had to do it), but the standards development is for 100 kV and above. What we are talking about makes a lot of sense – anything that comes out of NERC is a cost burden to us. TADS is incomplete now. This would make TADS more it useful.

Jim Robinson – Clarification -is this purely to ask for the incremental cost to report the requested data (for EIA 411 reporting) – i.e., the incremental costs for supply the TADS data vs. the cost to supply the data directly to EIA.

Brian Keel – a lot of members will have to hire a contractor to do this, esp. at 100kV and above level.

Motion to approve the Transmission Availability Data System (TADS) Proposed 100-199kV Automatic Outage Data Collection request be posted for a 45 day Public Comment pursuant Section1600 – *Request for Information and Data* of NERC's Rules of Procedures
Three "no's".
Two abstentions.
Approved

Motion – add request for the incremental cost information to supply the data beyond the costs of complying with the PRC and EOP Standards in the accompanying transmittal letter questionnaire.

Jeff M. and Ben C. opposed, two abstentions.
Passes

b. Model Validation Working Group Approve – Procedures for modeling development and validation - Eric Allen

Dale Burmester – not clear who will do the evaluation – ERO-RAPA? ERAG? MVTF?

Eric – the document does not address this – this is a technical document on how to do the evaluation. Technical documents are not standards. They are general recommendations that can be applied at many levels.
Dale – some of the recommendations are onerous – how long would you expect to do this – once a year, every five years?
Eric – This is just if you do it, this is a recommendation how to do it, nor when or how often.

Jeff M. – it's a report that the ERAG or MMWG can use.

Dale – what are we being asked to approved?
Eric – the public comment period has closed – asking PC to approve as a report. Comments received were incorporated.

Kenneth – page 1 comments – OK to match an operational condition, harder for planning cases; page 4 – assuming you are just looking for a few errors – not overall systemic flaws (like wrong base voltage); page 11 – SCADA measurement limitation – time synchronization of data is important when recreating events; and, accounting for errors in tolerances.

Dan R. – I'm on ERAG MC – believe this is supportive of what ERAG is doing; recognize some of these things may be difficult to achieve, but will be initially going after the low hanging fruit.

Approved

c. System Protection and Control Subcommittee
Approve to Post as Guideline – Use of Circuit Breaker Position Indication in Breaker Failure Protection - SPCS Chair - Jonathan Sykes

Incorporated comments received (none) – it's a technical report, not a guideline.

Approved

d. Reliability Assessments Subcommittee Mark Kuras, Chair of RAS (presentation in Agenda package)

Dave Weaver – recognize you guys have a lot to chew on – scope of the document is to do localized reliability impacts. Need to include details around units available for RMR.
Mark K. – that's the second bullet – not for approval now.

Approve – Gas Interdependency Study Scope

Nano – a lot of action items in the report – how will they be followed-up?
John Moura – the report will set the stage to identify the issues, then address them in the Phase II study – will meet with the gas industry to discuss (for instance, a lot of the recommendations came from the 2004 report).

Approved

Approve –Next Phase of EPA Regulations Study Scope
Mark K. - Out for review – looking for comments by December 30th – a lot of work is being done – perhaps we could leverage these on-going analysis – end of January, a small RAS subgroup will address comments – scope is not final – comments are greatly appreciated.

Paul K.– coming back to PC in March or at a February PC teleconference?
Jeff M. –could do at a February PC call, if ready.
John M. - Send comments to assessments@NERC.

Nano – who is doing the analysis? What about non-ISO/RTO areas?
Mark – pointing at planning authorities/transmission planners.
John M. – no intent for NERC to run its own studies – it's to leverage existing studies already being done.
Mark K.– moving away from the adequacy part of it – how do you solve the problem – transmission, new generation, etc – have to get to the transmission planners.

Nano – also looking for the time for retro fits, beyond 2016?
Mark K. – everything is on the table.

Mark K. – reviewed RAS accomplishments (as provided in the Agenda package) – his last meeting as RAS Chair.
Jeff M. – BOT recognizes the quality of the RAS work products. Thanks Mark, appreciate all your hard work.

Jeff M. – would like to do a round table of PC member's comments, opportunity for last minute comments.

- ✓ Ron M – more time to see/review agenda materials.
- ✓ Norman – send/post the presentations prior to the meetings.
- ✓ Jonathan S. – want to recognize the TIS – regarding FERC 754/definition of SPS – they are doing an amazing job, and a good collaboration with the SPCS.
- ✓ Like just making one OC/PC presentations rather than two.

End – 10:00 am December 14, 2011

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Draft
2012 NERC Corporate Performance Measures

February 2, 2012

During the last few years, NERC has been improving its process for measuring corporate and department performance against goals, objectives, and pre-established metrics. Incentive compensation for all NERC officers and employees is now tied to these yearend corporate and department results, as well as to individual performance assessments. NERC has most recently adopted internal tools for measuring individual performance to include electronic tracking of corporate and department results in 2012. Weighting among the corporate, department and individual components varies, depending on level of seniority in the company.

With each successive year, an effort has been made to improve the performance metrics themselves, first by reducing them to a smaller number of more important metrics (in 2010, NERC business activities totaled over 60 metrics spanning all NERC business activities). In addition, the substance of the metrics has been improved each year to increase the focus on results that improve reliability and to decrease focus on counting the numbers of NERC activities performed. This is a continuing challenge that will be refined each year as management strives to balance measuring results that NERC can directly control (e.g., NERC sponsored activities), versus the overall reliability performance of the bulk power system and risk mitigation.

NERC has collaborated with the eight Regional Entities to create a common strategic planning framework, the **Electric Reliability Organization Enterprise Strategic Plan 2012-2015**. This plan has evolved from the strategic plan that was reviewed by the NERC Board of Trustees (Board) in February 2011. The updated version of the Strategic Plan is being used by NERC and the Regional Entities as they formulate business plans and budgets for the coming year. For 2012, NERC is presenting its corporate performance measures using the framework provided by the ERO Enterprise Strategic Plan, spanning goals in three areas: 1) standards and compliance; 2) risks to reliability; and 3) coordination and collaboration.

The specific measures presented below were derived from goals and objectives outlined in the **2012 NERC Business Plan and Budget**, which was approved by the NERC Board on August 4, 2011 and accepted by the Federal Energy Regulatory Commission in its order issued October 20, 2011. The strategic plan from February 2011 was an additional resource.

The 2012 NERC corporate measures are subject to review by the Corporate Governance and Human Resources Committee on February 8, 2012, and approval by the Board on February 9, 2012.

2012 NERC Corporate Performance Measures – Draft February 2, 2012

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.

	Objective	Measure	2012 Target	2012 Stretch
1.	Develop a technically sufficient set of results-based reliability standards, with each requirement providing a clearly identified performance expectation and reliability benefit.	Number of new, or substantively revised standards delivered to board for approval, excluding retirements	12 standards	16 standards
2.	Be accountable to applicable regulatory authorities and the public for standards that provide an adequate level of reliability.	Year-end reduction (in percent) of standards-related directives remaining compared to 260 directives at 2012 year beginning. Total remaining at yearend includes any new directives issued	20% reduction to 208	30% reduction to 182
3.	Working with industry, develop options to improve the efficiency and timeliness of standards development such that high priority standards may be targeted for completion in one year.	Process revisions that meet the one year criterion	Drafted for public comment	Revisions complete and ready for board approval by yearend
4.	Work with industry to develop technical references or application guides for reliability standards to ensure clarity and facilitate implementation.	Develop plan a) listing priorities based on risk and clarity gap, and b) identifying formats and procedures (use existing formats as appropriate such as RSAWs, regional entity application guides, standards references, CANs, etc.)	Plan and templates developed	10 application guides delivered
5.	Develop a robust set of critical infrastructure reliability standards that enable industry to adapt to continuously changing threats and vulnerabilities by emphasizing security risk management.	Complete the CIP Version 5 standards (or equivalent) by yearend 2012	Approved by industry through successive ballot	Approved by industry through recirculation ballot and ready for board approval

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.

	Objective	Measure	2012 Target	2012 Stretch
6.	Continue to develop enhancements to enforcement processing to achieve efficient and timely compliance outcomes, including streamlined procedures for lesser risk violations and improved workflow and tools at NERC and regional entities. Explore alternatives to refining discretion focused on targeting violations most implicated in large events. Further develop FFT enhancements, spreadsheet NOPs, and other efficiencies and options for exercising discretion for lesser risk violations.	Average process duration for lesser risk violations filed in 2012 from discovery to filing, excluding those with discovery dates preceding July 1, 2011 Average process duration for greater risk violations from discovery to filing, excluding those with discovery dates preceding July 1, 2011 Yearend six-month rolling average of total FFT and spread-sheet NOPs filed monthly as a percent of active violations pending	6 months 12 months 4%	4.5 months 10 months 6%
7.	Reduce NERC/RE caseload index (proxy for how many months work remain in caseload).	Six-month rolling average of total active violations divided by monthly closings including dismissals		Scale from 12 months 100% credit to 22 months 0% credit
8.	Close outstanding enforcement cases with violation dates from 2007 – 2010.	Number of cases remaining unfiled for which violation date precedes January 1, 2011	75% reduction, excluding those held by proceedings at FERC or court	Zero left, excluding those held by proceedings at FERC or court
9.	Identify nature of violations associated with most significant system events and develop a plan for addressing risks in these areas.	Report on requirements most correlated to significant events (Category 3 and above) and plan for addressing risks	Report on risks correlated to significant events	Report on risk control strategies to address

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.

	Objective	Measure	2012 Target	2012 Stretch
10.	Develop a program to allow compliance trials following NERC board approval of reliability standards, for the purpose of allowing industry to come into compliance and mitigate compliance risk while the ERO validates compliance measures and procedures, minimizing inefficiencies and detrimental effects of learning through enforcement.	Develop report outlining process and instruments to be used, and identifying candidate standards for demonstration	Report published	Pilot initiated
11.	Educate industry on effective compliance programs and effective reliability risk controls.	Identify and document case studies of entities with exemplary compliance risk and reliability risk controls Continue CIP-002 Sufficiency Review Program (SRP) to evaluate entities' Critical Assets and Critical Cyber Assets lists	1 large entity and 1 small entity Conduct 8 SRPs	1 additional case study Conduct 10 SRPs
12.	Develop risk-based compliance monitoring approaches to maximize reliability benefits and improve efficiencies, and to encourage effective internal controls at registered entities.	Identify and assess through pilot testing alternative risk-based approaches to monitoring compliance, including use of sampling methods	Report on alternative approaches for monitoring compliance	Complete three pilot tests to demonstrate methods

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.

	Objective	Measure	2012 Target	2012 Stretch
13.	Trend reliability issues and improvement opportunities and share results transparently with bulk power system owners, operators, and users.	Report on state of reliability identifies risk clusters and trends	Report delivered by Q3	Report completed by Q2
14.	Provide a event analysis program that engages bulk power system owners, operators, and users in determining root causes, lessons learned, and other improvement opportunities; ensure all events meeting criteria are	Percent reporting of reportable events and quality of reports as measured by NERC review	100% of reportable events have reports submitted	80% approval according to quality review criteria

	catalogued, prioritized, and assessed for improvement opportunities.			
15.	Develop and maintain situational awareness capability that meets the needs of FERC, NERC, and applicable registered entities.	Delivery of SAFNR tool	System delivery and testing complete	All U.S. reliability coordinators connected
16.	Deliver reliability assessments of strategic emerging issues that may impact reliability.	Number of special issue reports approved	4 special issue reports approved	6 special issue reports approved

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.

	Objective	Measure	2012 Target	2012 Stretch
17.	Improve time to complete mitigation activities.	Average time from identification of a possible violation to entity stating mitigation complete	Mitigation times trend downward over 2012	Mitigation times reduced 10%
18.	Manage a consistent program for issuing advisories, recommendations and essential actions, and track and report mitigation results. Conduct these activities using tools, processes, and authorities.	Plan – design for tracking recommendations from alerts, event analysis, and other sources Tools – specify tool for tracking recommendations Implementation	Develop requirements and plan for tracking recommend-ations Specifications for tools System in testing	Tools: Implement NERC Alert system (build or buy) as scoped by 2012 Target Develop in SharePoint or acquire solution System operational
19.	Develop and implement risk management strategies for highest tier reliability risks.	Identify high priority risk management projects and develop plan Identify success measures and benchmark Implement plan	2 projects identified and planned Measures for each project Project started	3 projects Benchmarks complete On schedule at yearend

20.	Enhance situational awareness within the electricity sub-sector and with government through ES-ISAC, such as presence at NCCIC and other governmental classified forums.	Establish presence on NCCIC floor. Develop and implement initial declassified NCCIC framework in ES-ISAC Unclassified information products for registered entities based on classified sources Continue to expand ES-ISAC website to include secured members-only portal Classified briefings	2 ES-ISAC staff have access to NCCIC Design ES-ISAC wall of knowledge component Continually populate ES-ISAC portal with indicator bulletins Registration on ES-ISAC portal by 35% of registered entities 1 classified briefing	3 ES-ISAC team staffing access to NCCIC Test initial prototype Registration on ES-ISAC portal by 50% of registered entities 2 classified briefings
21.	Facilitate the conduct of comprehensive emergency, disaster, and business continuity planning.	Develop and test national security crisis response plan; test internally and then externally via participation in exercises, such as Cyber Storm IV d	Develop and review plans; test internally	Test internally and assess during 1 additional exercise, such as Cyber Storm IV
22.	Develop cyber security risk assessment tools for industry use, including maturity or mode of attack models.	Perform exercises based on attack tree modeling input and tied to maturity model output Support DOE maturity model initiative	4 exercises at host entities DOE adopts NERC framework	6 exercises at host entities DOE pilot completed

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.

	Objective	Measure	2012 Target	2012 Stretch
23.	Assist industry in improving reliability data modeling, including generator and turbine controls and load modeling.	Continue workshops on improved modeling. Engage all three interconnections in model improvement Execute plans to improve models. Prioritize improvements towards specific study	Report on improvement requirements and plan for improvement 2012 models suitable for Frequency Response Studies in the Eastern Interconnection. Document in a report to the PC	Data request to support model improvement Engage EPRI in improve load modeling research
24.	Align and expand the role of technical committees in supporting ERO functions and developing initiatives to improve reliability, with clear accountability to the board.	Engage committees by providing identified emerging reliability issues and seek joint solutions	Committees tracking on total of 6 key initiatives reporting to board	Comprehensive yearend report to board on priority initiatives and plans
25.	Complete and initiate demonstration of NIST/ DOE/ NERC cybersecurity guidelines for industry.	Finalize and implement comprehensive NIST/DOE/NERC Risk Management Guidelines	Finalize document and conduct public rollout	Initiate 3 demonstration users

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.

	Objective	Measure	2012 Target	2012 Stretch
26.	Maintain easy-to-navigate, accessible reliability information through a library of lessons learned from event analyses, best practices, examples of excellence, and other resources for reliability improvement.	Implement NERC public website using SharePoint 2010	Website operational	Implement metadata for rapid search capability
27.	Develop and implement an industry-wide communications plan to build awareness of work by the ERO and industry to improve reliability.	Develop quarterly reporting mechanism to detail ERO activities that addresses BPS risk	Reports for Q2-4 2012	Reports for Q1-4 2012

b) *Operate as a collaborative enterprise.* The ERO will communicate expectations clearly and foster collaboration to deliver important results in advancing system reliability.

	Objective	Measure	2012 Target	2012 Stretch
28.	Develop highly qualified and trained staffs at NERC and the regional entities, including enhancement of qualifications in auditing, investigations, enforcement, and other essential staff roles.	Develop certification criteria for critical ERO functions Conduct continuing training on auditing, investigating, root cause, and human factors	Auditor qualifications documented 95% of all auditors and investigators have 2 days of training or more	Investigator qualifications also 100% of auditors and investigators at NERC and regions, programs available to registered entities
29.	Deliver the initial modules of a secure information management system to achieve efficiencies, consistency of outcomes, effective process controls, and more transparent accountability across the statutory functions of ERO enterprise.	Deliver business requirements and functional requirements for one ERO application.	Design one agreed upon ERO application.	Implement one agreed upon ERO application.

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.

	Objective	Measure	2012 Target	2012 Stretch
30.	Develop an ERO-wide risk management program with effective internal controls to ensure the ERO is addressing organizational risks and successfully fulfilling its statutory mission.	Governance established Risk management executive hired Initial assessment and priorities reported 2012 work plan completed and budget for 2013		Charter approved Hire completed Report to RMICS by yearend 2012 work plan 100% complete and 2013 plan in budget

31.	Address recommendations and directives from the Three-Year ERO Assessment and previous audits.	Recommendations completed from 3 year assessment Recommendations completed from FERC audit and previous audits	90% 90%	100% 100%
32.	Implement additional operating and financial controls to improve resource efficiency and allocation	Budgetary performance 2013 NERC budget filed	Yearend working capital equal to or greater than budgeted 5% increase or less	Combined expense and fixed asset expenditures within budget 0% increase or less
33.	Better integration and decision making process with regions, including decision making with respect to management of overall ERO resources.	Improvements to EROMG governance and decision-making Organization and accountability of joint NERC and RE work groups ERO business planning	Updated charter All work groups assessed and have clear accountabilities Common goals and assumptions	8 leadership coordination meetings Completion of 100% of deliverables in work plans Total ERO 2013 statutory budget is 5% below projection filed in 2012, excluding WECC grant

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2012 NERC Performance Report

Initial Draft

Gerry Cauley
President and CEO
February 2012

RELIABILITY | ACCOUNTABILITY






Background

- 2012 corporate performance measures based on
  - 2012 corporate business plan and budget
  - Three-year ERO Performance Assessment
  - 2012-2015 ERO Enterprise Strategic Plan (goals, objectives, and pre-established metrics)
- Progress reviewed quarterly with management team
  - Goals and objectives shared with work teams to include the eight regions
  - Electronic tracking
- Results tied to performance compensation at corporate and department levels
  - Individual performance is third component

Three Major Goal Areas

- Corporate performance measures are structured around the framework provided by the ERO Enterprise Strategic Plan, spanning goals in three areas:
  - Standards and compliance
  - Risks to reliability
  - Coordination and collaboration

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Priority Objectives and Actions

- Develop new or substantively revised reliability standards
- Improve standards development
- Develop technical references or application guides
- Develop critical infrastructure reliability standards
- Reduce caseload index, close outstanding enforcement cases, and enhance enforcement process
- Identify violations associated with significant events and plan for addressing those risks
- Educate on effective compliance and reliability risk controls
- Develop risk-based compliance monitoring

Priority Objectives and Actions

- Trend reliability issues
- Provide event analysis program
- Develop and maintain situational awareness (includes ES-ISAC)
- Deliver reliability assessments or emerging issues
- Improve time to complete mitigation activities
- Issue advisories, recommendations, and mitigation results
- Develop and implement risk management strategies and emergency and business continuity planning
- Develop cyber security risk assessment tools
- Improve reliability data modeling

Priority Objectives and Actions

- Align and expand role of technical committees
- Demonstrate cybersecurity guidelines
- Develop lessons learned library and industry-wide communications plan
- Develop highly qualified and trained staff
- Develop modules of a secure information management system
- Develop an ERO-wide risk management program
- Address recommendations from Three-Year ERO Performance Assessment
- Implement financial controls and improve resource efficiency
- Integrate and improve decision making process with regions

NPCC, Inc.
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NPCC Board of Directors Policy Input to the February 8, 2012 NERC Member Representatives Committee and February 9, 2012 NERC Board of Trustees Meetings

1. ERO Enterprise Strategic Planning

a. NPCC supports the transitioning of the ERO's reliability enhancement strategy from an intensive document-based compliance enforcement regime, to a risk-based reliability performance focused approach included in the draft Strategic Plan

b. NPCC recommends the expeditious development of risk-based standards, the expansion of reliability performance focused compliance efforts, increased ERO Enterprise-wide staff training and informational workshops for industry, enhanced communications and tracking of applications of lessons learned from a robust events analysis program, development of meaningful reliability metrics based on technically sound reliability assessments, and the efficient leveraging of NERC, Regional Entity, and industry resources to achieve these objectives

2. Find, Fix, Track and Report Initiative

a. NPCC continues to support implementation of the Find, Fix, Track and Report (FFT) procedure as a forward advancement in NERC's continuing efforts to improve the efficiency and effectiveness of the ERO's compliance processes for Possible Violations that pose lesser risks to the Bulk Power System

b. NPCC suggests that NERC use the six month status report filing to also recommend that FERC act to approve FFTs filed in the future, in order to document regulatory closure with regard to mitigated Possible Violations

c. NPCC recommends that NERC accelerate its auditor training and industry informational webinars and workshop programs to introduce an FFT approach to the auditing process in the last quarter of 2012

3. Generator Owner (GO)/Transmission Owner (TO) Issues

a. NPCC supports limiting applicability of FAC-001 Interconnection Standard to Generator Owners interconnecting a third party facility to the GO's existing facility

b. NPCC also supports the limited applicability of FAC-003 for those GO/GOPs with interconnections greater than 1 mile, and the clarifying language in PRC-004 for coordination of protection related to generating facilities

c. NPCC continues to recommend that requiring GO/GOPs to register as TO/TOPs is not the appropriate mechanism to address any potential reliability gaps at the interface

4. Rules of Procedure Changes

a. NPCC supports the removal of some of the administrative details from the ROP and recommends further elimination of such implementation specifics to allow for innovation and operational efficiencies within a consistent, continent-wide context

b. NPCC strongly supports the ROP changes which accommodate an all independent member Hearing Body for compliance matters

5. Expedite Dissemination of Technical Information and Lessons Learned from Event Analyses and Investigations

a. NPCC is concerned with the delay in disseminating to the industry potentially critical lessons learned from significant events that are under multi-party investigation and recommends that NERC prioritize the early release of such reliability related information

b. NPCC recommends that NERC expedite the development of processes that would allow for the confidential sharing of detailed technical data associated with system events to those industry experts that could utilize such information to effectuate reliability enhancements in other registered entities

Approved by NPCC Board of Directors
At its February 1, 2012 Meeting

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February 12, 2012

To: **NPCC Board of Directors**

From: **Harvey J. Reed**

Re: **NERC Meetings of the Member Representatives Committee and Board of Trustees – February 8th and 9th**

Ladies and Gentlemen:

A review of the above referenced meetings is provided below for your information.

Member Representatives Committee – February 8th

I. Remarks by Gerry Cauley, NERC President and CEO

1. Summarized NERC's achievements for the year as follows:
   a. BES definition and associated Rules of Procedure changes filed
   b. Prioritized Standards under development
   c. Implemented FFTR process
   d. Developed Events Analysis Process
   e. Assessments – breakthrough in ability to analyze and measure risk
   f. Completed Gas - Electric Interdependency Report
   g. Performed Grid Exercise
2. NERC's Performance Goals were set around the Strategic Plan that was developed with the Regions. NERC and the Regions are committed to: a) marry risks with reliability outcomes; b) use risk based compliance; c) apply risk based standards; and d) coordinate to ensure consistency.

II. Strategic Plan and Goals

1. Gerry Cauley explained that the Board of Trustees asked NERC to include "No Category 5 events" as one of the 2012 performance goals and that NERC was in process of assigning weights.
2. Comments
   a. Cost effective reliability should be part of objective.
   b. Strategic goals should be incorporated into operational plans and coordinated with Regions
   c. Cost effective reliability can be incorporated in operational plans and coordinated with the Regions by transforming the list of activities that constitute the operational goals into "measureable outcome based goals". NPCC Regional President is already charged with developing these types of goals so this would be a good time to work together.

III. Standards Development Process Improvements

1. Gerry Cauley commented that the changes to the standards development process should allow NERC to develop quality based standards. However, there is an enterprise risk to the ERO if we can't produce effective standards in a timely manner. He has a sense of urgency to get good and sufficient standards. He asked whether: a) the process improvements are sufficient to allow the standards process to become more efficient; b) are we using the right resources and teams to produce the standards; and, c) do we have a sustainable governance structure.
2. Comments
    a. Industry should not be cut out of the process. The proper role for NERC is as the professional facilitator. However, prioritization needs to occur.
    b. MRC should take on the function of dealing with this issue so standards process as intended in legislation can be implemented efficiently. However, standards are not and shouldn't be divorced from the compliance enforcement process. The debate is over the enforcement impacts on registered entities and we need to get over that issue and get on with it.
3. MRC set up group of the MRC leadership, including Canadian representation, trade groups and some BOT representatives to address the standards process improvements to meet the enterprise risk to the ERO. Scott Helyer will report back at the May MRC Meeting.

IV. Rules of Procedure Updates

1. Description of rules of procedure changes proposed and modifications made in response to stakeholder comments.
2. Comments were generally favorable to the changes NERC made, but the sense was that the timing of the circulation of the modified revisions did not provide sufficient time for stakeholders to comment and so more time would be appropriate.

V. Events Analysis Update- Gerry Cauley commented that Reports are developed and presented to Regions through a secure portal where information can be shared based on confidentiality agreement.

VI. Generator Owners and Operators that own and operate transmission facilities

1. The standards make it clear who should be included, but Regions can use an impact based approach.
2. Comment was made as long as the potential for a lot of registrations based on an impact based approach isn't large we should go ahead with the standards.

VII. Interpretation of Communication Protocol for when three part communications are required (COM-002-2)

1. Comments
    a. The interpretation of the standard is based on a strict construction
    b. The standard is based on the industry knowing what are and are not emergency conditions and if the registered entity fails to apply it during emergency they are subject to compliance enforcement.
    c. A level of discomfort with the interpretation was expressed by Paul Barber.

VIII. Presentations

1. ALR Update
2. BES definition

3. Geomagnetic disturbance
4. Compliance Enforcement Initiative
5. Culture of Reliability (Lincoln Electric)

Board of Trustees Meeting – February 9th

1. Chairman Anderson reported that the BOT representatives on the standards process group established by the MRC would be Paul Barber and Ken Peterson.
2. President's Report –This is a period of transition. The challenge is turning all the activities and initiatives into a risk based reliability organization that is articulated in the strategic plan. The priorities are:
    a. Reliability top issues- human error, relays and Cyber Security
    b. Take on cold weather event and make sure it doesn't happen again
    c. Use event data to seek a solution to reliability issues by developing lessons learned in conjunction with Transmission Forum and Regions.
    d. Trying to demonstrate there is value created by the ERO
    e. Sustainable programs for the maintaining clearances in right of way without creating undo costs. - Gerry is interested in ideas on how to reduce congestion while maintaining right of way.
    f. Gerry poses the issue: Is compliance getting in the way of reaching the strategic goals?
        i. He believes that compliance is one tool that can be used as assuring reliability. He wants to make sure that it is fair and administrated consistently across all Regions. However, NERC needs to continue to be a strong enforcement agency while moving the trust dial upward with regulators and the industry.
3. ERO Strategic Plan
    a. Gerry Cauley comments
        i. We are getting close with the strategic plan
        ii. Common framework and a lot has been done to coordinate the plan
        iii. Plan is focused on problem solving and risk based controls
        iv. NERC and Regions to develop risk based controls with the industry so collaborative activity is important to make plan a reality
        v. Will take a look at the performance goals and see if we can change the focus onto reliability outcomes as opposed to activities
        vi. The targets and the allocations will go to the CGHR
    b. Board comment – NERC should make changes to 2012 goals to make sure that they are focused enough, measurable and based on reliability outcomes.
4. Standards and Interpretations
    a. GO/TO Issue – there were three standards presented, but one is under administrative appeal. FAC-001-1(facility connection requirements) and PRC-004-2.1a (Analysis of Generation and Transmission Misoperations) are ready for Board Approval, but FAC-003 was appealed by Exelon based upon the process between the original ballot and the recirculation ballot.
        i. The Board discussed and approved FAC-001-1 and PRC-004-2.1a, but told NERC to hold filing until the package was complete and technical justification to accompany the filing was developed. This approach

avoids the potential for FERC issuing a directive to fill in the gap crated by not filing the complete package. This provides the industry with the opportunity to fill the gap before the standards are filed.

b. CIP-006-1 – approved
c. COM-002-2 – There was a substantial discussion engaged in by the entire board. The issue was that the interpretation left an ambiguity and some were very concerned about the risk to reliability such an interpretation would allow. However, the appropriate fix is to draft a new standard that makes it clear when three part communications are required. A motion was made to approve the interpretation subject to developing best practices on the use of three way communications and the Standards Committee placing the drafting of a new standard as a very high priority. The motion approved with Paul Barber abstaining.
d. Interpretation of MOD-028 for FPL – approved
e. Regional Standards
    i. PRC-006-NPCC-1 –Automatic Underfrequency Load Shedding-There were several questions from the BOT including whether NERC needs regional standards. Mr. Schwerdt responded by explaining that this standard took the general NERC standard to a specific requirement, which eliminated the lumpiness of the underfrequency load shedding and added additional trip frequencies as compared to an older NPCC Criteria. Standard was approved unanimously.
    ii. SERC Regional Standards Development Procedure- Approved

5. NERC Rules of Procedure substantive changes – consideration was deferred pending comments to be submitted by February 17th.
6. Electric Sub-Sector Information Sharing Policy Statement – Approved
7. Event Analysis Process Manual- Approved
8. FRCC Amendments to Delegation Agreement- Approved
9. Reports and Presentations
    a. Status of Critical Infrastructure Initiatives
    b. Standing Committee Reports including Compliance and Certification Committee; Critical Infrastructure Committee; Member Representative Committee; Operating Committee; Personnel Certification and Governance Committee; Planning Committee; Standards Committee; Electric Sub-Sector Coordinating Council
    c. Forum and Group Reports including NAESB; Regional Entity Management Group; North American Transmission Forum; North American Generator Forum
    d. Board Committee Reports
        i. Corporate Governance and Human Resources-used Mercer to conduct compensation study
        ii. Finance and Audit Committee- BOT Approved unaudited financial statements
        iii. Board of Trustees Compliance Committee
        iv. Standards Oversight and Technology

From: Tina McClellan
To: Tina McClellan
Subject: NERC: POSTED: Presentations and Addendum Items - February 2012 Meetings
Date: Saturday, February 04, 2012 5:53:53 PM

POSTED

Presentations and Addendum Items

Board of Trustees, Member Representatives Committee, and Board Committees' Meetings

February 8-9, 2012 – Phoenix, AZ

Schedule of Events

Policy Input

Corporate Governance and Human Resources Agenda Item 10b

Standards Oversight and Technology Committee Presentations

Compliance Committee Open Session Presentations

Member Representatives Committee Presentations
Member Representatives Committee Agenda Item 6

Board of Trustees Presentations

For more information or assistance, please contact Tina McClellan.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Announcement

Collaboration and Education Key Topics at NERC Board Meeting; Three Standards Approved

February 13, 2012

PHOENIX -- The North American Electric Reliability Corporation (NERC) had its quarterly Board of Trustees meeting on February 9 in Phoenix. NERC President and Chief Executive Officer Gerry Cauley welcomed participants with a look back at accomplishments of 2011 and a look forward to the electric reliability organization's (ERO) 2012 goals.

"In 2011, the ERO enhanced our ability to analyze and interpret data, which allows NERC to identify specific risk areas and provide tools and methods of action to industry," Cauley said. "The collaboration between NERC, the Regions and industry was instrumental to the ERO accomplishing its 2011 goals: the completion of the bulk electric system definition; the Find, Fix and Track compliance enforcement initiative; and the gas-electric interdependency assessment, among many others."

In 2012, NERC will continue to ensure the strength of the ERO's reliability programs by focusing on three major goal areas 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.

During this meeting, the board approved three reliability standards, Project 2010-07 Generator Requirements at the Transmission Interface (FAC-001-1 and PRC-004-2.1a) and Project 201-INT-01 Rapid Revision of Area Methodology (MOD-028-1); and two interpretations, Project 2008-10 Interpretation of Cybersecurity – Physical









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Security of Critical Cyber Assets (CIP-006-x) and Project 2009-22 Interpretation of Communications and Coordination (COM-002-2).

Project 2009-22 (COM-002-2),which applies to real-time emergency communications, was approved with an amendment that calls for the prioritization of a revised standard and a best practices memorandum shared with industry.

Two regional standards, Automatic Underfrequency Load Shedding (PRC-006-NPCC-1) and SERC's Reliability Corporation Regional Standards Development Procedure, received board approval as well.

A policy statement was approved to ensure the separation of functions between the Electric Sector-Information Sharing and Analysis Center (ES-ISAC) and the Compliance Monitoring and Enforcement Program. Because NERC is responsible for both the ES-ISAC and the compliance program, NERC wanted to ensure that duties were separated to encourage a greater flow of information between industry participants and ES-ISAC staff.

Also, approved was the ERO event analysis process document, which develops a cohesive coordinated process throughout North America to ensure the distribution of timely and actionable lessons learned to the industry. This document was developed through collaboration with the industry through the Event Analysis Working group.

In other business, the board re-elected John Q. Anderson as board chair through February 2013, with Fred Gorbet elected to serve as vice-chair and chair-elect. Board members Ken Peterson, Bruce Scherr and Jan Schori also were re-elected to the board for three-year terms. Gerry Cauley was re-elected as president and chief executive officer of NERC. NERC's next board meeting is May 9 in Arlington, Va.

The board contributed its support to a new undertaking by NERC and the Member Representatives Committee to review the current standards development process and provide a proposal for improvement. A steering group will commence in the upcoming weeks and a report to the BOT is expected by May.

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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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

John Q. Anderson, Chair
NERC Board of Trustees

January 17, 2012

Mr. Scott Helyer, Chair Elect
NERC Member Representatives Committee
Vice President, Transmission
Tenaska, Inc.
1701 E. Lamar Blvd.
Arlington, Texas 76006

Re: Policy Input to NERC Board of Trustees

Dear Scott:

First, congratulations for being elected to lead the Member Representatives Committee (MRC) in 2012. Bill Gallagher did an outstanding job, so you have a tough act to follow.

After carefully reviewing the agenda for the February 8, 2012 MRC meeting, I would appreciate receiving policy input from the committee members on the following activities, priorities, or other areas of interest:

Update on ERO Enterprise Strategic Planning – Following the November Board of Trustees (Board) meeting, NERC and the Regional Entities rededicated efforts to coordinate a collaborative network, the ERO Enterprise, that brings together their collective leadership, experience, judgment, skills, technology, and duly delegated statutory responsibilities for the purpose of ensuring the reliability of the bulk power system (BPS). As the strategic planning of the ERO Enterprise continues into the New Year, the Board would welcome feedback on how to best identify priority areas of interest, common objectives and responsible business practices. Gerry Cauley will review 2011 performance with the Corporate Governance and Human Resources Committee (CGHRC) at its meeting on February 8, 2012, and plans to present proposed 2012 goals for Board approval at its February 9 meeting. The Board welcomes MRC input on these 2012 goals, as well as longer-term strategic directions for the ERO Enterprise, by way of written policy input as well as open discussion at the MRC meeting on February 8.

Find, Fix, Track, and Report Initiative – NERC and the Regional Entities continue to employ a comprehensive and integrated risk control strategy that differentiates and addresses compliance issues according to their significance to the reliability of the BPS. As NERC and the Regional Entities increase their enforcement discretion in the implementation of compliance and enforcement activities, the Board is interested in hearing the committee members' perspective on the implementation of the Find, Fix, Track, and Report (FFT) process. Your input will also assist NERC in preparation for its six month status report to the Federal Energy Regulatory Commission.

Generator Operator (GO)/Transmission Operator (TO) Issues – NERC has suspended work on the entity registration guidance directive intended to clarify those standards and requirements applicable to GO/GOPs that would be registered as TO/TOPs. NERC will consider the following two outcomes prior to making any further decision to resume work on compliance guidance for the GO/TO initiative:

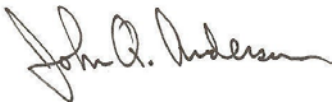
1) Guidance from the Board on the proposed revision of FAC-001, FAC-003 and PRC-004 (Standards Project 2010-07).
2) The final FERC approval of the NERC compliance filing concerning the upheld registry of Cedar Creek and Milford Wind as TO/TOP with appropriately scoped applicable standards.

The Board is particularly interested in policy input on the standards being presented for approval at its February 8 meeting, as well as any comments on the overall issue.

Rules of Procedure Changes — The Board would like to hear of any concerns the committee has with the general direction of the proposed substantive changes to the Rules of Procedure that the Board will consider for approval at its meeting on February 8. Are these changes, to date, effectively addressing the issues raised during previous MRC and Board meetings?

Thank you in advance for providing written comments to Dave Nevius, MRC secretary (dave.nevius@nerc.net) and Holly Mann (holly.mann@nerc.net) **by January 30, 2012** so they can be packaged and sent to the Board members in advance of the meeting.

Thank you,



John Q. Anderson, Chair
NERC Board of Trustees

cc: NERC Board of Trustees
Member Representatives Committee
Regional Executives

Canadian Electricity Association | Association canadienne de l'électricité

NERC Board of Trustees Policy Input – Canadian Electricity Association
February 9, 2012

The Canadian Electricity Association ("CEA") appreciates this opportunity to provide policy input to the NERC Board of Trustees. CEA's comments do not address any of the specific issues identified in NERC Chairman John Q. Anderson's letter dated January 17, 2012, but another matter that is of particular importance to Canadian industry members.

In these comments, CEA focuses exclusively on recent NERC proposals regarding the optimal means for improving the NERC standards development process. CEA believes that the representation of the unique perspective of NERC's Canadian members is warranted, in view of the recent introduction from NERC staff of a draft proposal for an alternative process, the strong reaction from stakeholders, and the strong likelihood that deliberations at the February 2012 sessions will shape the timing and scope of efforts to modify the process going forward. CEA's goal is to help ensure that the discussions and decisions of the February meetings are based on a fully informed understanding of those elements of the NERC standards process which are essential for purposes of NERC's relationship with entities in Canada.

Accordingly, CEA wishes to express strong support – and to echo the applicable principles set forth in the Joint Trade Associations' policy input – for retaining the criteria enabling registered entities to actively and effectively participate in the standards process with respect to drafting the technical content and voting on a proposed standard.

Indeed, the basis for the enduring acceptance of and support for the NERC model among CEA members is the stakeholder-driven, collaborative and consensus reaching process for the development of standards, whereby stakeholder experts draft, comment on, and ballot a standard, NERC approves it, and the applicable governmental authorities ultimately accept or reject it for adoption in their respective jurisdictions, or remand it to NERC for further review. This process presents the opportunity for active, effective participation by Canadian stakeholders and industry experts. It ensures that Canadian stakeholders are included in the development of standards applied in their respective jurisdictions, and that the specific content of a standard is determined by the expertise of industry stakeholders who best understand how the interconnected bulk power system is planned, designed, built, operated and maintained.

Likewise, the principle of a stakeholder-driven process has been and remains critical to the acceptance of the NERC model by the applicable governmental authorities in Canada responsible for electric reliability oversight. In fact, this principle is expressly enshrined in frameworks governing the development and adoption of reliability standards in various Canadian jurisdictions – whether these frameworks are structured through legislation, regulation, or direct agreements or Memoranda of Understanding ("MOUs") with NERC.

Various frameworks in Canada explicitly recognize the importance of effective participation by industry stakeholders in the development of reliability standards. The excerpts below from various MOUs executed between NERC, Regional Entities – where applicable – and the

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following Canadian entities clearly illustrate this principle:

Independent Electricity System Operator ("IESO")
"*The signatories recognize the importance of the involvement of Ontario market participants … and the IESO in the development of NERC reliability standards…The IESO's statutory objects*, inter alia, *include participating in 'the development by any standards authority of standards and criteria relating to the reliability of the transmission systems' and 'to establish and enforce standards and criteria relating to the reliability of transmission systems.'*"

Régie de l'énergie (Québec)
"*NERC and NPCC undertake to develop electric power transmission reliability standards applicable to Québec in accordance with their procedures, namely the* NERC Reliability Standards Development Procedure *and the* NPCC Regional Reliability Standards Development Procedure. *To this end, NERC and NPCC undertake, within the framework of their respective procedures, to take note of the comments and opinions submitted by the Québec reliability coordinator, the electric power carriers and users of electric power transmission services in Québec.*"

Saskatchewan Power Corporation
"*The Parties acknowledge the importance of the active participation of any electricity sector participants from the Province of Saskatchewan in the Reliability Standards development process.*"

CEA therefore emphasizes that any plan to improve the standards process which limits stakeholders' ability to actively participate therein would require consultation with Canadian governmental entities and may constitute a violation of NERC's obligations to Canadian entities, as prescribed in provisions such as those cited above.

CEA recognizes that the existing standards development process may stand to benefit from targeted enhancements. At the same time, CEA does not believe that the process suffers from inherent flaws which are so severe as to warrant a wholesale overhaul. Moreover, CEA cautions against the adoption of process modifications that potentially sacrifice the technical quality of standards for the sake of procedural expediency.

For the immediate purposes of the Board's February meeting – where there will likely be extensive discussion on NERC staff's draft proposal for an alternative process and on what next steps are necessary for pursuing changes to the existing process – CEA wishes to convey the above information so that the Board's deliberations with the MRC can rest on secure assumptions of what process improvements will be compatible with the various reliability frameworks in place in Canadian jurisdictions.

CEA thanks the Board for considering these comments and looks forward to discussing these matters further in Phoenix.

CEA Contact:
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Director, U.S. Affairs
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NERC Board of Trustees

Phoenix

February 9, 2012

Policy Input of the Edison Electric Institute

On behalf of our member companies, Edison Electric Institute (EEI) is pleased to offer the following brief policy input in advance of next week's NERC Board of Trustees meeting in Phoenix. EEI's views on NERC and bulk power system reliability are shaped by its CEO Task Force on Reliability, CEO Task Force on Business Continuity, and the Reliability Executive Advisory Committee. We look forward to a productive discussion of the issues in Phoenix.

NERC STRATEGIC DIRECTION

EEI appreciates the Board of Trustees seeking policy input on the 2012 and longer term strategic direction of the NERC corporate enterprise. We offer the following observations to inform this critically important discussion:

- EEI appreciates that the Board of Trustees seeks to continuously sharpen the strategic focus on the enterprise. Companies organize the full range of their management decisions around such plans, and we urge the Board to ensure that the plan governs management decisions throughout NERC and the regions. We generally agree with the strategic goals in the draft plan. In future discussions, we look forward to discussing with NERC management and the Board of Trustees the metrics that will be developed to inform decisions on measuring success.
- In addition, we ask that the Board consider incorporating in the strategic plan a more clearly stated basis or background statement to recognize the overall strong and resilient state of the bulk power system. The broad range of issues identified in the U.S. – Canada Blackout Report (April 2004) have been addressed. Enforcement of mandatory standards has been put in place, including methods to emphasize vegetation management, system awareness and communication, emergency procedures, personnel training, and system protection. Since enactment of Section 215 in 2005, NERC has a solid record of achievement in standing up as the Electric Reliability Organization, approving the initial set of mandatory standards, and maintaining leadership on addressing critical technical issues.

- We also ask that NERC recognize that NERC must set clear limits for itself and anticipate that a much more disciplined approach to evaluating reliability risks will support the definition of these limits. Sharpening the definition of reliability risks will also help NERC decisions on cutting or postponing those projects that distract from higher priority work.
- A critically important fundamental for NERC strategic planning rests within the explicit language of Section 215, which recognizes that unexpected events take place on the system, that the core mission of the Electric Reliability Organization is to set standards that seek to control the effects of such events. The bulk electric system is planned and operated with significant levels of redundancy in anticipation of an enormous range of contingencies. For decades, system planning and operations have recognized that sudden disturbances or unanticipated events --- equipment failure, human error, and weather --- will take place and challenge the electric industry.
- Timely root cause analyses, sharing lessons learned and best practices, and providing feedback to standards development, must all continue to improve. However, the ERO role should be limited to its core competencies of coordinating, and when appropriate, performing the event analysis. NERC should allow the industry itself, from the full information of timely-released event analysis reports to determine lessons learned and best practices. EEI believes that this division of labor is appropriate and will allow the ERO to concentrate on its core mission of standards development, compliance and enforcement and assessments.
- On technical matters, EEI believes that appropriate strategic emphasis for resources should be placed on system protection and critical infrastructure protection. Both of these areas involve highly complex matters, evolving technologies, considerable costs, and the strong need for careful attention to ensuring that reliability risks are clearly defined, and solutions tailored to those risks. More in-depth discussion of the broad range of activities and technical work should be organized by NERC management and coordinated through the standing technical committees.
- We are also convinced that NERC needs to continue improving its own program management and administration. Both core program areas, standards development, and compliance and enforcement, are becoming overwhelmed with process and paperwork, which EEI believes now comprises at least several hundred million dollars of overheads that contribute very little to bulk power system reliability.

FIND, FIX, TRACK, REPORT (FFTR)

EEI applauds the Board of Trustees for supporting this critical initiative. Compliance and enforcement comprises almost 50% of the ERO enterprise-wide budget. The paperwork and administrative processes have become overgrown with unnecessary matters that provide little benefit for reliability. FFTR is an important first step in providing much needed relief.

- The recently issued NERC survey should help inform decisions on whether FFTR is providing relief and what regional differences may exist in the program deployment.

We also look forward to providing more detailed comments on FFTR to NERC by February 23 in response to a recent announcement that such comments are being solicited.

- NERC should continue to aggressively seek to reduce cost overheads and find the right methods and tools to ensure that costs are reduced. FFTR results should achieve cost savings at NERC, within the regions, and for the companies. We urge NERC to seek from companies more specific information on cost savings.
- Initial statistics suggest that some regions are beginning to use FFTR. EEI looks forward to the regions reporting their experiences to date at the upcoming meetings.
- Training for compliance program area personnel to ensure process consistency across the various regions is a critical piece of this overall process.

In addition to FFTR, we understand that NERC compliance operations initiated a process that in the future might allow for varying the frequency or intensity of various audits and other compliance activities, depending on an "entity assessment" that NERC will perform. NERC staff recently announced a series of focus group activities to help shape this process. EEI urges NERC to carefully develop this tool with clearly stated goals and objectives, and with reasonable due process and transparency. While companies envision that this tool may support successful implementation of more tailored risk-based application of compliance activities, information to date suggests that the tool and how it will be applied must be much more clearly defined and communicated to companies.

GENERATOR OWNER/ TRANSMISSION OPERATOR ISSUES

EEI appreciates the efforts of the team members of Project 2010-07 and NERC staff to review reliability aspects associated with generator requirements at the transmission interface. This project is an important step in the continuing consideration of registration and applicability issues that have been raised in various recent FERC orders. The project drafting team analyzed and identified reliability-based areas of improvement. The resulting revisions present well-founded approaches to a reliability question. The ballot results indicate strong industry support for these revisions. In considering approval, the Board should also be aware that Exelon submitted a level 1 appeal of the FAC-003 ballot and that the Board will not be voting on this standard at this meeting.

In addition, we understand that there a narrow jurisdictional issue may arise in the context of FAC-001, where under certain circumstances, the proposed revisions could impose Section 215 requirements on generators prior to any actual interconnection taking place with the bulk electric system and to becoming FERC jurisdictional. this could wrongly pre-judge the generator interconnection issues, and expand jurisdiction beyond the statutory provisions of Section 215 of the FPA. Careful consideration should be given that these revisions do not create a contradiction with FERC Order No. 2003 and Order No. 2006 regarding generator interconnection requirements to the Transmission Owner/Transmission Operator as well as

any confidentiality provisions imposed under these rules. We ask that the Board consider this potential issue in its consideration of approving the standards.

RULES OF PROCEDURE CHANGES

Last month, trade associations provided joint comments on a broad range of proposed changes to the Rules of Procedure (ROP). Along with specific comments on the detailed ROP changes, trade associations stated strong concern about the lack of transparency in the process and the failure by NERC to include the rationale for seeking the ROP changes. Given the size and scope of the proposed changes, and the apparent discretionary nature of the changes, trade associations' comments stated a strong belief that NERC should state the reasons that changes are being proposed, including the reliability or management issue that is being addressed.

We appreciate that NERC has provided an explanation of the proposed ROP changes, a summary of the comments and the response taken, as well as a redline of the proposed changes. This is a major step toward the transparency sought by stakeholders to enable us to better respond to the proposed changes. We recognize that this involved a significant effort by NERC staff. We appreciate that staff made changes to some of the ROP in response to the comments filed, particularly withdrawal of the proposal to impose penalties for failure to respond to a data request, modification of the provision on certification of questions to the Board of Trustees Compliance Committee and deferral of the request for Board approval of Appendix 8 concerning events analysis.

Our initial impressions are that we support the changes now being proposed. However, due to the sheer volume of the redline text of the ROP changes that was released on January 30 and the press of other business, we have not had a chance to review the proposed changes in depth with member companies. Therefore, we ask the BOT to defer approval of the proposed changes for a short period to enable stakeholders time to adequately review the proposed changes and convey any remaining concerns to NERC staff and the Board. We recommend that NERC set a deadline of Friday, February 17 for receiving stakeholder views.

STANDARDS DEVELOPMENT PROCESS

EEI endorses a separately submitted February 2 statement of principles on changes to the NERC standards development process. EEI believes that the process is improving but still needs further improvements. Defining strategic reliability priorities must continue being refined. Threshold decisions on the need for new or significant modifications to standards can be strengthened. Balloting and commenting can be made more efficient without sacrificing ANSI principles. Debates over VSLs and VRFs can be time consuming efforts without offering much incentive for strong reliability performance.

Further specifics:

The results-based design approach needs to continue and grow. While some drafting teams are incorporating these design principles, others may be challenged. More work is needed to ensure that the results-based design is incorporated in the entire standards catalog. Longer term, we envision that achieving the goals of both results-based approaches for standards development and significant enforcement forbearance as delivering significant efficiency gains.

The standards development project pipeline has far too many projects underway for efficient outcomes. Threshold decisions needs to be improved to better identify the need for standards and their priorities.

Drafting processes should continue to strengthen their project management and increase their use of legal and regulatory support. The recent addition of a quality review has provided important value to the process. Defined milestones and deadlines are needed for all projects.

Along with improvements to the front-end, EEI also strongly believes that NERC should improve its advocacy at FERC by improving the presentation of the technical merits of its various proposals filed at FERC. NERC staff already performs an enormous amount of work in assembling the various filings, however, pre-filing conferences and substantive justifications of the new ERO-approved standards would be invaluable to FERC staff and commissioners' assistants who are overwhelmed with issues and filings.

Policy Input to the NERC BOT and MRC – February 8, 2012

The Electricity Consumers Resource Council (ELCON) is pleased to offer the following policy input to the NERC Member Representatives Committee and the Board of Trustees.

In addition to the specific replies to issues listed by NERC Chairman John Q. Anderson, ELCON raises two high-level concerns:

1. Large industrial electricity consumers need a reliable supply of electricity, but it must be at competitive prices. Increasingly, compliance with the growing numbers of NERC standards requires tremendous quantities of resources at increasing costs – particularly as it seems they are *de facto* zero-tolerance standards. Commissioner David Wright, Vice Chairman of the South Carolina Public Services Commission and current President of the National Association of Regulatory Utility Commissioners, was recently quoted as saying that consumers will be asked to pay new costs of between $2.2 and $4.1 trillion dollars in the "near future," primarily for new regulations and infrastructure.[1] Industrial consumers simply cannot stand such cost increases and remain competitive in worldwide markets. NERC must do its part and find ways to balance compliance to necessary standards with consumer costs.

2. While entities required to be in compliance with NERC standards want clear and concise standards, increasingly they are concerned that NERC staff, rather than industry stakeholders, are making unilateral determinations that in essence become mandatory actions. The approved ANSI-approved standards development process should be followed to the greatest degree possible. The NERC Board and staff should give greater consideration to input from the stakeholders.

Responses to specific issues raised in Chairman Anderson's letter:

Enterprise Strategic Planning – ELCON believes that the overall state of the bulk power system is strong and resilient. Increasingly, detailed joint comments have been filed with NERC on a variety of critical issues by a broad range of stakeholder groups. While certainly more needs to be done, these joint comments, at least to ELCON, suggest that industry stakeholders are working together and are united in their beliefs that radical changes are not needed. Yet, NERC seems intent on pushing significant changes without appropriate counsel and input from stakeholders. As a specific example, NERC proposed a "CEO summit" on improving the standards development process. That "summit" is now being reconsidered, although NERC staff suggest that "clarifications are to follow." That could be interpreted as positive. But then a conference call scheduled by NERC staff only created further confusion. Industry is being asked to provide input upfront on what direction such a summit should take and what issues should be pursued if a big meeting (no longer a "summit") is held (maybe in

[1] "Urgency of NARUC Call For EPA Rule Flexibility Rises With Rate Recovery," remarks of NARUC President David Wright, ***Inside EPA's Clean Energy Report***, January 19, 2012.

April). ELCON questions the need and value of such a summit or big meeting. Specific ways to improve the NERC standards process already have been proposed and should be explicitly addressed before incurring the costs and efforts of such a big meeting.[2]

Find, Fix, Track, and Report (FFTR) – ELCON applauds the BOT for supporting this critical initiative. Compliance and enforcement comprises almost 50% of the enterprise-wide NERC budget. The FFTR process should help reduce paperwork and administrative costs that do not actually benefit reliability. NERC should continue to aggressively seek to reduce compliance and enforcement costs.

Generator Operator/Transmission Operator Issues (GOTO) – The GOTO directive that created a firestorm is being postponed pending some form of review or other input. We hope that this is a positive sign. NERC staff did not participate in the GOTO drafting team's efforts or provide the team with any input until very late in the process, and now they are trying to impose significant changes. ELCON consistently has said that NERC staff should be encouraged to express their thoughts and ideas through timely written submissions. These submissions should be considered just like any other comments. However, NERC is, and should continue to be, a stakeholder driven organization that is fair, balanced, open and inclusive. NERC staff should be sensitive to the wide range of stakeholder positions as it prepares its comments and not take sides on any issue.

Finally, ELCON believes that FERC's orders are clear that registration of GOs/GOPs as TOs/TOPs must involve a fact specific analysis of each GO/GOP to determine the materiality of the GO/GOP to the reliability of the bulk electric system. While NERC has suspended work on the interim directive (#2001-CAG-001), it is not clear what, if any, aspects of the directive NERC will seek to implement after it receives (1) "Guidance from the Board on the proposed revision of FAC-001, FAC-003 and PRC-004 (Standard Project 2010-07)" and (2) "The final FERC approval of the NERC compliance filing concerning the upheld registry of *Cedar Creek* and *Milford Wind* as TO/TOP with appropriately scoped applicable standards." To ensure that any subsequent NERC action on this overall issue is lawful, NERC must abandon any attempt to implement a bright-line test for registering GOs/GOPs as TOs/TOPs. FERC's orders involving *Cedar Creek* and *Milford Wind* are clear that registration of GOs/GOPs as TOs/TOPs must involve a ***fact specific analysis*** of each GO/GOP to determine the materiality of the GO/GOP to the reliability of the bulk electric system.

Rules of Procedure (ROP) Changes –Chairman Anderson's letter states that "The Board would like to hear of any concerns the committee has with the general direction of the proposed substantive changes to the Rules of Procedures that the Board will consider for approval at its meeting on February 8." ELCON is concerned about both the specific changes proposed and the entire process being taken relating to proposed changes to the ROP. We are not alone. Concerns have already been expressed by many other stakeholders. In fact, a broad range of trade associations provided joint comments on a range of proposed changes including: specific comments on the detailed ROP changes, a strong concern about the lack of transparency in the process, and a failure by NERC to include the rationale for seeking the ROP changes. The joint

[2] See for example comments presented at the FERC Reliability Technical Conference on November 29, 2011, FERC Docket No. AD12-1-000.

trade groups' comments are still germane and are attached to the Policy Input for this meeting by the Edison Electric Institute. We urge the NERC staff to respond specifically to the various comments already filed before taking any further actions. In addition, the final version of proposed ROP changes should be posted at least two weeks prior to NERC Board meetings in order to allow stakeholders a meaningful opportunity to review and provide comments prior to submission to the Board for approval.

With respect to the specific changes proposed in Agenda Item 9, ELCON offers the following comments. Because of the short time available to prepare the following comments (the final version of the ROP changes was posted only 3 days ago), the comments are not comprehensive and silence on any proposed change should not be construed as acquiescence.

Section	Comment
ROP § 202; Appendix 4C § 1.1.9	Although the definition of "Confirmed Violation" was changed, the term "Confirmed Violation" remains inconsistent with the definition since the definition includes settlements, which can be resolved with the Registered Entity neither admitting nor denying a violation.
ROP §§ 403.15 & 409.1	The proposed revisions that would allow "a regional entity" to appeal the outcome of a hearing completed pursuant to the regional entity's own hearing process is flawed. Pursuant to ROP § 403.15, the "regional entity hearing process shall be conducted before the regional entity board or a balanced committee established by and reporting to the regional entity board **as the final adjudicator**" (emphasis added). The regional board or designated hearing committee is not the "final adjudicator" if a regional entity is allowed to appeal the outcome of a hearing. The insertion of "regional entity" in ROP § 403.15 is also inconsistent with the more limited insertion of "regional entity acting as the compliance enforcement authority" in ROP § 409.1. Regardless, allowing the regional entity (or subgroup therein) to appeal its own decisions is fundamentally incompatible with the appeal process set forth in Section 409, which governs appeals from final decisions of regional entities. It is axiomatic that decisions that a regional entity can appeal are not final. Contrary to the "Justification/Notes" in the Summary Matrix, the Regional Entity Hearing Body is not a wholly "independent tribunal" because its authority to act stems from delegated power from the Regional Entity. If such tribunals were wholly independent, they would be devoid of any enforcement powers. The proposed revisions, which would allow the Regional Entity to appeal the decision it delegated to another entity, essentially also results in rending the hearing body impotent. It would eliminate the value of the hearing process at the regional entity level because it effectively grants the regional entity veto power over its own decision. Thus, the regional entity references in the last paragraph of ROP § 403.15 and in ROP § 409.1 should be deleted.

ROP §§ 407 & 413	The proposed insertion of "including penalties, sanctions and remedial action directives that are specified by a regional entity hearing body final decision" in Section 407.1 should be deleted. In addition, Section 413 should be deleted in its entirety. They should be deleted because they refer to a "regional entity hearing body final decision," which is not a defined term and creates ambiguity. Moreover, if the use of this phrase is intended to distinguish a "regional entity hearing body final decision" from anything other than the "final decision" of the regional entity, it is fundamentally contrary to the hearing process. See comments to ROP §§ 403.15 & 409.1, above.
Appendix 4B, ***passim***	The deletion of the term "remedial actions" from Appendix 4B could be construed to mean that remedial actions required by NERC or the regional entity are different from other enforcement mechanisms such as penalties and sanctions. As explained above, NERC's only enforcement authority is to enforce compliance with reliability standards. Moreover, "[a]ny penalty imposed under [FPA § 215] shall bear a reasonable relation to the seriousness of the violation and shall take into consideration the efforts of such user, owner, or operator to remedy the violation in a timely manner." (16 USC § 824o(e)(6)). Regardless of whether it is called a penalty, sanction or remedial action, any enforcement action taken by NERC must be to enforce compliance with a reliability standard and must be "reasonable." Appendix 4B should therefore clarify that "remedial actions" mandated by NERC or the regional entity will be treated in the same manner as other enforcement actions.
Appendix 4B, § 3.3.1	All enforcement activities under FPA § 215 must be directly tied to enforcing compliance with reliability standards, and all penalties must bear a "reasonable relation to the seriousness of the violation." (16 USC § 824o(e)(6)). The proposal in Section 3.3.1 to "take into account" the compliance history of affiliated entities in the penalty determination process violates both of these principals. The actions of an affiliate do not bear upon whether an entity violated a reliability standard. Moreover, the actions of an affiliate does not influence whether a penalty is reasonable in relation to the seriousness of an entity's own violation. In fact, affiliates often do not remain static, and an entity's current affiliates may not have been affiliates at the time of the alleged violation. Accordingly, the following sentence should be stricken from this section: "In evaluating the violator's compliance history, NERC or the regional entity will take into account previous violations by affiliates of the violator, particularly violations of the same or similar reliability standard requirements, and will evaluate whether any such prior violations reflect recurring conduct by affiliates that are operated by the same corporate entity or whose compliance activities are conducted by the same corporate entity."

Appendix 4C, § 5.11	The "Special Procedures for an Enforcement Action Against an ISO/RTO" proposed in Appendix 4C, § 5.11 are unlawful because they are discriminatory and grant preferential treatment to ISOs and RTOs. FERC can only approve a rule that is "just, reasonable, not unduly discriminatory or preferential." (16 USC § 824o(f)). Section 5.11 of Appendix 4C should therefore be deleted in its entirety.
Appendix 4C, §§ 1.1.30 & 3.5	The proposed insertion of "or may have" in the definition of Self-Report in Section 1.1.30 should be deleted because it is ambiguous and conflicts with the definition of Self-Report in Section 3.5. Requiring an entity to submit a self-report whenever it "may" have violated a reliability standard would be unenforceable because there is no benchmark to determine when an entity would be deemed to believe it "may" have violated a Reliability Standard. Moreover, the proposed revision could be interpreted to permit a penalty assessment for not submitting a self-report even if there is no actual underlying violation of a reliability standard, which is contrary to FPA § 215. Finally, the proposed revision would substantially increase administrative costs and burdens because it would shift the burden of conducting the initial review of a potential violation from the registered entity to the regional entity. The Summary Matrix clarifies that a Registered Entity is not required to submit a Self-Report whenever it believes it may have, but is not certain, that it has violated a Reliability Standard. This clarification should be included the ROP to avoid unnecessary confusion and dispute in the future.
Appendix 4C §§ 3.0, 5.0 & 6.0	Proposed revisions in Appendix 4C would allow the Compliance Enforcement Authority ("CEA") to "collect documents, data and information in the manner it deems most appropriate, including requesting that copies be made of Documents, data and information and removing those copies from the Registered Entity's location in accordance with appropriate security procedures…" (This quote appears in Sections 3.0, 5.0 and 6.0 of Appendix 4C). The proposed revisions do not provide any protection against unjustified information collection burdens under the Paperwork Reduction Act of 1995 and does not account for other basic rights afforded regulated entities. (*See* the discussion regarding Section 800 and Appendix 8, above). The proposed language is also unlawful, as it would bestow the CEA with practically unfettered discretion in the area of access and data collection. The caveat that the information collection must conform to security procedures and "other safeguards as appropriate" (*id*.) is insufficient. There is a statutory limitation on the boundaries of what NERC, and even FERC, can collect. For example, an administrative agency is prohibited from going on a general "fishing expedition" for information as it "deems most appropriate," including searching both relevant and irrelevant documents, hoping to uncover a violation. (*See, e.g., FTC v. American Tobacco Co.,*

	264 U.S. 298 (1924)). Under FERC's regulations, the standard for providing information is not whether the CEA deems it "appropriate." Rather, FERC's regulations are clear that a registered entity is only required to provide "such information as is necessary to implement Section 215 of the Federal Power Act." (18 C.F.R. § 39.2(d)). FPA § 215, in turn, states that the purpose of NERC and the regional entity is "to establish and enforce reliability standards." (16 U.S.C. § 824o(a)(2)). The CEA's power to collect information is therefore limited to ensuring compliance with the reliability standards. Thus, the proposed language should be revised to "collect copies of documents, data and information necessary to establish and enforce reliability standards."
Appendix 4C, § 5.7	The first sentence of this section granting the CEA the right to appeal the decision of the regional entity's hearing body should be deleted. (See comments to ROP §§ 403.15 and 409.1, above).
Appendix 4C, Attachment 1(1)	The statement that "NERC or a Regional Entity may take the steps described in this section where a registered entity in the United States fails to provide, in a timely manner and in the form requested, information requested by NERC or a Regional Entity in connection with a compliance monitoring or enforcement process" is too broad that it leaves room for enforcement actions outside the scope of NERC's jurisdiction. FERC's regulations provide that a registered entity is only required to provide "such information as is necessary to implement Section 215 of the Federal Power Act." (18 C.F.R. § 39.2(d)). FPA § 215 unambiguously states that the purpose of NERC is "to establish and enforce reliability standards." (16 U.S.C. § 824o(a)(2)). NERC's, and therefore a regional entity's, power to collect information is therefore limited to establishing compliance with and enforcing reliability standards. To the extent Attachment 1 would penalize a registered entity for action or inaction unrelated to a violation of a reliability standard approved by FERC, including "fail[ing] to produce the requested information," it violates FPA § 215 and is unlawful. Therefore, the data collection process should be clarified to ensure a link between the "monitoring" and "enforcement" and an enforceable Reliability Standard. Finally, "[a]ny penalty imposed under [FPA § 215] shall bear a reasonable relation to the seriousness of the violation and shall take into consideration the efforts of such user, owner, or operator to remedy the violation in a timely manner." (16 U.S.C. § 824o(e)(6)). Against this jurisdictional backdrop, "Step 2" and "Step 3" of the proposed Process for Non-Submittal of Requested Data in Attachment 1 to Appendix 4C are clearly unenforceable. Specifically, in Step 2, NERC or the regional entity cannot "implement a compliance monitoring process directed to the Registered Entity," or "apply a Reliability Standard violation at the severe violation severity level," or impose any other penalty if the registered entity at issue did not violate a reliability standard. That is,

	"Step 2" and "Step 3" can only be lawful if used by NERC or the regional entity to enforce compliance with reliability standards. Moreover, if a registered entity violates an applicable reliability standard, any corresponding penalty must bear a reasonable relation to the seriousness of the violation of that reliability standard, including efforts to remedy the violation of the reliability standard.

Conclusion:

Due to both the number of and significance of the comments by both ELCON and others, we urge the BOT NOT to take action on February 9th on the proposed changes to the ROP.

Electric Power Supply Association
Advocating the power of competition

NERC Board of Trustees
Phoenix, Arizona
February 9, 2012
Policy Input of the Electric Power Supply Association

On behalf of its member companies, the Electric Power Supply Association ("EPSA")[1] appreciates the opportunity to provide policy input in advance of next week's NERC Member Representatives Committee ("MRC") and Board of Trustees ("BOT") meetings in Phoenix. EPSA supports the BOT, NERC management and MRC leadership for recognizing the value of stakeholders' policy input in advance of the MRC and BOT meetings and how that input can play an important role in informing the BOT leadership on issues impacting the Electric Reliability Organization's ("ERO") evolution.

In his January 17 letter, BOT Chair John Q. Anderson highlighted for MRC Chair Scott Helyer the activity, priority and policy issues on which the BOT seeks comment. Herein, EPSA responds to those noted areas of interest. The comments remain consistent with the last two EPSA policy submissions in preparation for the MRC and BOT meetings regarding strategic direction and priorities. NERC, as an organization, should be focused on programs and processes that materially support reliability and increase the ERO's efficiency and effectiveness. Program and process development and deployment should be supported by material evidence of their need and value. The new Find, Fix and Track ("FFT") initiative serves as an example of a valuable program that can be measured and is showing success. EPSA continues to be concerned about a multitude of other new programs that create duplicative, unclear processes that could undermine ERO efficiency and effectiveness. Actions such as these undermine the ERO goal of instilling a high degree of trust among stakeholders. They are contrary to the shared goal of a strong ERO.

Update on ERO Enterprise Strategic Planning

EPSA looks forward to Gerry Cauley's review of 2011 ERO performance and his release of the organization's 2012 goals at the Corporate Governance and Human

[1] EPSA is the national trade association representing competitive power suppliers, including generators and marketers. Competitive suppliers, which, collectively, account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities serving power markets. Each EPSA member typically operates in four or more NERC regions, and members represent over 700 registered entities in the NERC registry. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

Resources Committee ("CGHRC"). The January 24 inclusion with the MRC meeting materials give some indication of the 2012 presentation. The 2011 review should reveal valuable information about the ERO's measurable progress. As EPSA has asserted in the past, a measured evaluation is important in setting priorities and areas of emphasis for 2012 and beyond. Issue areas should demonstrate value to reliability efforts and to improving the ERO organization. The January 24 inclusion makes no mention of how 2011 results influenced the 2012-2015 ERO Enterprise Strategic Plan. Moreover, the 2012 Strategic Goals do not list any specific measurable goals.

The Commission notes in its NERC Business Plan and Budget Order (Docket No. RR11-7-000) that the ERO's principal goals for 2012 include:

(1) developing clear, results-based reliability standards;
(2) promoting a culture of industry learning and reliability excellence;
(3) providing effective measures of reliability and risk performance;
(4) facilitating effective management of critical infrastructure tasks;
(5) ensuring effective and timely compliance and mitigation;
(6) providing an effective and efficient ERO enterprise; and,
(7) instilling a high degree of trust and confidence in the ERO.

EPSA believes that the last two goals result from the effective management and successful achievement of the first five. If the first five have specific measurable goals for 2012 it will make formulating 2013 goals a much more efficient process.

Find Fix, Track and Report Initiative

EPSA thanks the BOT for supporting and acting on this critical process improvement that will increase organizational efficiency and allow for more emphasis on reliability initiatives. Compliance and enforcement represent a significant amount of the ERO's annual resource commitment including a significant effort on compliance aspects with little risk to reliability. Initiatives like FFTR that streamline documentation requirements and violation processing, are a positive first step. EPSA supports the ERO's continued efforts and believes continued emphasis on the additional steps and phases of the initiative will promote success for this priority initiative. Because the compliance resource commitment makes up half of the NERC budget, initiatives that will bring compliance spending more in balance with the other five ERO goal areas is the right approach. The recently issued NERC FFT survey should help inform decisions on program successes and aspects in need of adaptation. EPSA believes that ensuring consistent coordination of this program will be the cornerstone of its success. EPSA encourages the ERO to continue to provide and stress training for compliance program area personnel. This should be considered a priority area for resources.

Generator (GO)/Transmission Operator (TO) Issues

EPSA has long been engaged on the "GO/TO" issue, noting in its May of 2009 BOT policy input the need for the ERO to make the issue a priority. As such, EPSA is pleased to see that Project 2010-07, Generator Requirements at the Transmission interface (GO/TO project) revisions of FAC-001 and -003, and PRC-004, are before the BOT for approval at the Phoenix meeting. Approving this Standard is the appropriate next step. The GO/TO project drafting team analyzed and identified reliability-based areas of improvement. The resulting standard revisions present well founded approaches to resolving reliability issues.

EPSA members supported and participated in the Standards process that drew on technical expertise and honored comments from the breadth of industry segments and stakeholders. We applaud the work of the Standards Drafting Team ("SDT") for completing Project 2010-07 with consensus support across Bulk Power System segments.

EPSA appreciates that NERC suspended the Compliance Process Directive. This will better facilitate clear consideration of Project 2010-07. In addition, there are those that cite the Commission decision on the individual registrations of Cedar Creek and Milford as having broader compliance impacts rather than reliability implications. EPSA believes that the Cedar Creek and Milford compliance filing is an individual case about those units. Those cases should remain focused on the units in question and not be part of the BOT's consideration of Project 2010-07. Approving the Project 2010-07 standard revisions will ensure that NERC supports incremental improvements to Reliability Standards.

Rules of Procedure Changes

EPSA, in conjunction with the other trade associations, provided joint comments on a broad range of proposed changes to the Rules of Procedure ("ROP"). Much of the comments reassert points made in prior EPSA comments (August of 2011) and joint trade comments (December of 2011). Those comments state that the ROP changes to date do not effectively address issues raised during the two previous MRC and BOT meetings. Along with comments on the specific ROP changes, trade associations expressed their strong concern over the lack of transparency in the process and the failure by NERC to include the rationale for seeking the ROP changes. At the August meeting, NERC promised to share the rationale and conduct further discussion at the November meeting. EPSA is encouraged that it appears that supporting rationale has been included in the January 29 posting to the BOT meeting materials. While EPSA appreciates the posting there has not been sufficient time to review the materials. Given the importance of these changes it is important that the ERO give sufficient time for stakeholder input and BOT review so that appropriate final decisions can be reached.

Standards Development Process

EPSA endorses the February 2, 2012 Trade Association Standards Development Principles submitted by APPA to the BOT as part of its policy input and looks forward to the discussion at the Phoenix meeting on this priority topic. The principles lay out an appropriate template for identifying inefficiencies in the standards development process that can be changed. Such an identification process will allow for continual improvement evaluation measures.

Sincerely,
/s/
Jack Cashin
Director, Regulatory Affairs
Electric Power Supply Association

ISO/RTO Council's (IRC) Policy Input to Board of Trustees

1. Update on ERO Enterprise Strategic Planning

The Board would welcome feedback on how to best identify priority areas of interest, common objectives and responsible business practices.

The Board welcomes MRC input on the 2012 goals, as well as longer-term strategic directions for the ERO Enterprise, by way of written policy input as well as open discussion at the MRC meeting on February 8.

IRC's Input

The IRC believes that identification of priority areas should be based first on identified/measured impacts on real time system reliability; and secondly on identified/measured risks to that real time reliability.

The IRC supports longer-term initiatives that are based on:

- Providing guidance that presumes Industry support and is verified by the ERO.
- Light handed "regulations," using Guides and Lessons Learned.
- Evaluating the relationship of reliability and of standards to responsible entities in the context of the restructured Industry.

2. Find, Fix, Track, and Report Initiative

IRC's Input

The IRC fully supports the FFT initiative on the basis that the initiative:

- Enhances reliability by recognizing proper behavior and encouraging reliability entities to resolve the reliability impact by quickly correcting any errors that occur, and by expeditiously applying any lessons learned.
- Enhances reliability by allowing the ERO to better deploy its resources on critical reliability issues, as opposed to diluting the effectiveness of these resources by deploying them on matters having a weaker link to reliability.
- Increases consistency of behavior and compliance enforcement, and leads to better transparency of the process.

The IRC suggests that FFT could become even more effective if:

- The ERO, in its six-month status update to FERC, seeks the Commission's recognition of the current FFT initiative.
- The FFT initiatives be further streamlined to a set of simple high-level transparent rules that can be applied by the compliance enforcement authorities and responsible entities to

reduce subjectivity in compliance decisions, and further reduce scrutiny of low-impact events, and in so doing free up resources to review and assess high-impact events.

- The FFT process were better reflected in determining the reliability risk of individual entities. The FFT process recognizes that self-reported, self-resolved incidents are indications of a self-healing organization that is improving reliability. However, the IRC notes that when it comes to computing the "reliability risk" of an entity, it appears so far that self-reported, self-corrected incidents would be viewed the same as non-corrected violations. The ERO should consider eliminating the self-reported, self-corrected incidents from this reliability risk calculation.

3. Rules of Procedure (ROP) Changes

The Board would like to hear of any concerns the committee has with the general direction of the proposed substantive changes to the Rules of Procedure that the Board will consider for approval at its meeting on February 8. Are these changes, to date, effectively addressing the issues raised during previous MRC and Board meetings?

IRC's Input

Appendix C:

- While the proposed changes to the ROP do address some of the issues identified by the IRC and industry groups, including the major trade associations, in the comments submitted to NERC on December 21, 2011, NERC has retained unnecessary provisions that also raise material legal concerns. In the case of Appendix C, section 5.11, the IRC comments raised fundamental questions concerning NERC's authority under US federal law. **As detailed below**, **the IRC repeats the request it and others made in December 21 comments that the Board of Trustees not adopt ROP changes related to ISO/RTO direct assignment of penalties (see Appendix 4C, Section 5.11 and related provisions)**.

- ***Problems with Proposed ROP Relating to ISO/RTO Direct Assignment of Monetary Penalties***

  As originally proposed, the changes to Appendix 4C, section 5.11 inappropriately and impermissibly limited, and attempted to regulate, the rights granted by FERC to ISOs/RTOs to directly assign certain monetary penalties to specific member companies. Despite NERC addressing a number of the legal issues identified by the IRC and other industry groups, the provisions continue to have serious flaws. Specifically, the proposed language inappropriately and impermissibly: (a) expands NERC's oversight role to review the legal adequacy of ISO/RTO filed-rates; (b) confuses the rights Third Parties have to intervene in the enforcement proceeding in those situations where the ISO/RTO and the ERO enter

into a Settlement Agreement, and (c) maintains a legally inaccurate definition of an ISO/RTO.

- ***NERC's Proposal to Review the Legal Adequacy of ISO Tariffs and Governing Documents Incorrectly Presumes NERC Has Authority Under Section 205 of the Federal Power Act.***

  NERC's proposal requires ISOs and RTOs to present to NERC for review and agreement that their tariffs and/or contracts provide for the right to allocate a penalty to a third party that caused the penalty. This proposal puts NERC in the position of making a legal determination of whether the ISOs and RTOs have the legal rights to assign a penalty.

  This determination puts NERC in the legally impermissible position of a rate regulator, infringing upon the ISO/RTOs' rights under Section 205 of the Federal Power Act to allocate certain costs to its customers. In the 2008 Guidance Order, FERC made clear that NERC's role is simply to determine whether third parties caused or contributed to the alleged violations. In other words, did companies other than the ISOs/RTOs, through their acts or omissions, play a material role in the event that NERC alleges results in an ISO/RTO being deemed to be in violation of a Standard?

  NERC has already represented to the Commission that it will undertake a "root cause" analysis in enforcement proceedings to determine the actual cause of a violation so that reliability may be improved rather than simply stopping the inquiry at the Registered Entity.[1] Therefore, NERC's stated rationale for conducting such legal determinations – *i.e.*, that NERC would avoid undertaking substantial work in understanding the role other companies played in events resulting in alleged violations of Reliability Standards – is plainly at odds with NERC's prior comments to FERC, and as importantly, at odds with enforcing Standards in a manner that improves reliability.

- ***NERC Confuses the Rights of Third Parties When the ISO/RTO and the ERO Elect to Settle an Alleged Violation***

  The proposed revisions confuse a Third Party's right to participate in a root cause analysis and an enforcement proceeding with the participation of a third party in a settlement. As

[1] *See generally* NERC Comments (Docket AD07-12) at 7-10; *see id.* At 8 ("NERC submits that the presumption (unless and until proven inaccurate) should be that these detailed investigative, hearing and appeal processes will result in identification of (all of) the entities whose actions caused or contributed to a reliability standard violation."); *See also* Reliability Standard Compliance and Enforcement in Regions with Regional Transmission Organizations or Independent System Operators (2008 Guidance Order), 122 FERC ¶ 61,247at P9 (Both at the technical conference and in written comments filed afterwards, NERC stated that *it is committed* to uncovering the root causes of Reliability Standard violations.")

noted, NERC is conducting a root cause analysis, making an independent assessment about the role third parties played in a violation without assigning a penalty allocation amount to them. The latter is FERC's role, exercised in connection with a Section 205 filing by an ISO or RTO to assign the penalty.

When understood that way, a Settlement Agreement *simply addresses*: (1) the ERO and the ISO/RTO settling on whether or not there was a violation of the Standard that applies to the ISO/RTO and (2) the penalty amount, mitigating & corrective actions. It is therefore incorrect to include in the Rules of Procedure a requirement that any third party that is participating in an enforcement proceeding ***must consent*** to any settlement agreement.

- ***The ROP incorrectly define ISOs/RTOs***

Third, the definition of ISOs and RTOs proposed for the ROP continues to be legally incorrect. As presented in the proposed ROP revisions, the definition states:

> ISO/RTO: A FERC-approved independent transmission system operator or regional transmission organization with exclusive and independent authority under section 205 of the Federal Power Act (16 U.S.C. 824d) to propose rates, terms and conditions of transmission service provided over the facilities it operates.

If the intent is to limit the definition of ISO/RTO to those organizations located in the United States, the definition should be revised to state: An independent system operator or regional transmission organization approved by the FERC or the Public Utility Commission of Texas.

The additional language is incorrect as Section 205 rights are not the controlling element of an entity's legal designation under FERC Orders No. 888 or 2000. Rather, an ISO or RTO may have exclusive 205 rights over certain parts of a tariff and joint 205 rights, or may not have 205 rights at all, over other parts.

Based on their review, the IRC strongly urges the Board to reject these ROP changes at this time.

Appendix 8: The Withdrawal of Appendix 8 from Board of Trustees' Consideration is proper.

- In addition, the IRC supports NERC withdrawing the proposed Appendix 8 ("Event Analysis") from the ROP. The proposed modifications related to Appendix 8 conflict with the Operating Committee-endorsed process. NERC did not coordinate the ROP changes with the Operating Committee, and NERC did not explain why such a high level of detail on the EA program was needed in the ROP.

General Comments: Improvements are needed for how NERC proposes changes to the ROP.

- Finally, and as a general matter, the IRC urges the Board to direct NERC to adopt protocols that would establish greater transparency around ROP development.

- While the IRC appreciates NERC's recent efforts to better explain the basis and substance of proposed sets of changes, small additional efforts to facilitate stakeholder input in this area would yield great improvements in prioritizing changes and improving final work product. Most importantly, prior to presenting ROP changes for industry review and comment, NERC should explain the "problem" being sought for resolution, what adverse impacts this "problem" is creating, and how NERC's proposed solution is effective in addressing it.

  The IRC proposes that NERC:

  1. Publish a regulatory schedule with quarterly updates of planned ROP changes.

  2. Seek CCC (or other appropriate committee) input to flag any potential significant issues prior to publishing actual language for review/comment.

  3. Add webinar/committee presentations contemporaneous with posting of proposed changes.

  4. Consider extending comment periods for proposed ROP changes.

  5. Improve prioritization of work effort by reviewing ROP changes, CANs, Standards, and Data Requests scheduled for comment in any particular calendar quarter.

  ISOs/RTOs have extensive experience with managing stakeholder processes for filing rule/tariff changes with the FERC and can be available to discuss improvements to the ROP change process in more detail. The steps outlined above will give the industry the opportunity for advance input, which is likely to result in a better end product. Additionally, this type of coordination would also minimize or avoid public disagreement between NERC and the industry at the MRC, BOT or FERC level. Finally, this approach should also result in the timely release of a "finalized" product; stakeholders should not be given a 3-4 day window, as is the case for this BOT meeting, to provide the BOT with input on ROP changes. There may be other areas in which the IRC would have liked to offer its support, or conversely, to express questions or concern.

4. Interpretation for Approval

IRC's Input

The IRC would like to note its support of the **COM-002 R2 Interpretation**. The IRC's Standards Review Committee (SRC) submitted the Request for Interpretation over two years ago. It garnered over 94% industry approval and should be approved by the BOT at its February meeting.

The Large Public Power Council

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MEMORANDUM

From: William Gaines, CEO, Tacoma Utilities, on Behalf of the Large Public Power Council

To: Dave Nevius, Secretary
NERC Members Representatives Committee

Subject: Response to Request for Policy Input

Date: February 2, 2012

The Large Public Power Council (LPPC[1]) submits this response to the letter dated January 17, 2012 from NERC Board Chairman John Q. Anderson to Scott Helyer, acting in his capacity as Chairman of the NERC Member Representatives Committee (MRC). LPPC has reviewed and concurs with the policy input submitted by the State-Municipal and Transmission Dependent Utility sectors (SM-TDUs) on topics to be discussed by the NERC MRC and the NERC Board of Trustees at their respective meetings on February 8th and February 9th, 2012. Additionally, LPPC supports the February 2, 2012 Trade Association Standards Development Principles. We provide these separate comments to elaborate on our concerns with the proposed changes to the NERC Rules of Procedure (ROP).

The changes proposed to the ROP would radically modify the dynamics of the enforcement process. LPPC appreciates NERC staff's rationale for the proposed revisions articulated in the matrix that was posted for the first time this past Monday. Unfortunately, insufficient time remains for the industry to adequately respond to the rationale presented by NERC staff, or suggest compromise language that would meet the objectives of NERC staff while addressing industry concerns.

In particular, the proposed revisions would provide the Regional Entity with the right to appeal the decision of a Regional Entity hearing body. Providing the Regional Entity with the same appeal rights as afforded to the registered entity runs counter to the spirit of the

[1] LPPC represents 25 of the largest state and municipal utilities in the nation, with members that own approximately 90% of the transmission assets owned by non-federal public power utilities. The council's members are listed below.

Austin Energy (TX) • Chelan County PUD (WA) • Clark Public Utilities (WA) • Colorado Springs Utilities (CO) • CPS Energy (TX)
ElectriCities of North Carolina, Inc. (NC) • Grant County PUD (WA) • IID (CA) • JEA (FL) • Long Island Power Authority (NY)
Los Angeles Department of Water and Power (CA) • Lower Colorado River Authority (TX) • MEAG Power (GA) • Nebraska Public Power District (NE)
New York Power Authority (NY) • Omaha Public Power District (NE) • OUC (FL) • Platte River Power Authority (CO)
Puerto Rico Electric Power Authority (PR)) • Sacramento Municipal Utility District (CA) • Salt River Project (AZ) • Santee Cooper (SC)
Seattle City Light (WA) • Snohomish County PUD (WA) • Tacoma Public Utilities (WA)

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enforcement process reflected in Section 215 of the Federal Power Act. Under section 215, the appeals process begins when a penalty is assessed against a registered entity, who then has the opportunity to appeal the penalty. No other right of appeal is contemplated. This makes sense, because the statutory structure provides the entities that are subject to enforcement appropriate due process, while securing the finality of the decision-making process. Appeals from a Regional Entity to NERC should be no different. It is inappropriate to modify the Rules of Procedure in a manner that would allow the Regional Entity to file an appeal with NERC every time that it disagrees with the finding of that Regional Entity's hearing body.

In explaining this proposed revision, NERC staff points out that the hearing body of a Regional Entity is a tribunal separate from and independent of the Regional Entity's Compliance Program, and for this reason the Regional Entity should have appellate rights commensurate with those of the registered entity. NERC staff also argues that the Regional Entity must have the ability to bring any disputed matter to NERC for ultimate disposition.

On the first point, the very purpose of the hearing process is to provide the registered entity with a fair, independent, and nondiscriminatory process when contesting the findings of a Regional Entity. Accordingly, it stands to reason that the hearing body would be independent from the Regional Entity compliance program. The existing version of the ROP recognizes that the purpose of the hearing process is to protect the due process rights of the registered entity. Providing the Regional Entities with unconditional appellate rights undermines these rights. Because registered entities have limited resources, the decision to take a matter to hearing will not be taken lightly. Allowing a Regional Entity to appeal the decision of a Regional Entity hearing body significantly reduces the likelihood of a timely resolution of the issues, and has a "heads I win, tails you lose" quality, since it holds the potential of undermining litigated results, and creates a strong disincentive for registered entities to pursue their rights. Indeed, as a practical matter, the proposed changes may render the hearing process meaningless by compelling registered entities to risk spending limited time and resources in endless litigation when a Regional Entity files an appeal.

On the second point, NERC staff proposes other revisions to the ROP that ensure NERC's role in the Regional Entity hearing process, in particular the authority to review and process final decisions of Regional Entity's hearing body. This right would apply even when no party appeals the decision of the hearing body, and would allow NERC to modify any hearing body decision when necessary to ensure consistency in violation and penalty determinations among Regional Entities. Given the proposed addition of this language to the ROP, providing the Regional Entity with separate and additional unconditional appeal rights unreasonably tilts the hearing process in favor of the Regional Entity, and goes further than is necessary to protect NERC's interests.

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LPPC urges the NERC Board to defer taking any action on the proposed revisions to the ROP at this time so as to provide the industry and NERC staff with additional time to develop a more balanced approach that meets the needs of all involved.

Austin Energy (TX) • Chelan County PUD (WA) • Clark Public Utilities (WA) • Colorado Springs Utilities (CO) • CPS Energy (TX)
ElectriCities of North Carolina, Inc. (NC) • Grant County PUD (WA) • IID (CA) • JEA (FL) • Long Island Power Authority (NY)
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POLICY INPUT TO NERC BOARD OF TRUSTEES

FEBRUARY 2, 2012

Pursuant to the NERC Board of Trustee's request for policy input from the NERC Member Representative Committee for the upcoming February 8, 2012 meeting, the Midwest Reliability Organization ("MRO") Board of Directors respectfully submits the following for consideration by the NERC Board of Trustees.

ERO Enterprise Strategic Planning

MRO generally supports the NERC strategic direction in finding ways to provide more value in improving reliability and security of the bulk power system. However, MRO is concerned with the significant number of priorities that NERC has identified and suggests core emphasis in the following areas:

1. Standards

The Standards-setting process needs to be revised to deliver better, faster results while continuing to leverage the technical expertise of the industry.

NERC and the Regional Entities should devote more time to working with industry technical leaders in the development of application guides to clarify standards and assure that they are well understood and applied rigorously across North America. Subject Matter Experts from the MRO Region have developed application guides which have provided positive results in reducing the number and severity level of violations. Providing better clarity on expectations will also lower costs of compliance for the ERO enterprise and the Registered Entities.

2. Recognizing Risk in the Compliance Monitoring and Enforcement Program (CMEP)

MRO suggests the program place much more emphasis on measuring the strength of the Registered Entity's corrective action and internal risk control programs to determine the level of "reliance" Regional Entities can place on Registered Entities. MRO is concerned that any proposed approach which fails to account for measuring corrective action and risk control programs will not result in a true "risk based" program. Once an approach and corresponding program is established, a strong roll-out plan to ensure the revised program is properly implemented and discretion is handled in a principled and fair manner by the Regional Entities and NERC staff is required. Proper discretion follows a well-designed risk-based approach.

3. Reducing Costs of Compliance

The current approach of implementing the Compliance Monitoring and Enforcement Program has driven compliance costs to unsustainable levels. These costs are reflected in higher annual budgets for NERC and the Regional Entities but do not reflect the time and costs that the industry devotes to compliance. While the FFT process will most likely result in cost savings for NERC and the Regional Entities, more effort is needed to reduce end-to-end compliance costs in the industry. The implementation of a "risk based" approach to compliance will increase rigor and substantially reduce overall administrative burdens. This approach would emphasize strong Registered Entity internal corrective action programs and management risk controls for ongoing assurance that Bulk Power System (BPS) risks are being addressed and improvements made to reliability and security – resolving small matters before they become significant.

4. Event Analysis

Event Analysis is the "low hanging fruit" for improving reliability. An event allows for a practical examination of the application of the standards and concomitant insight into their effectiveness. Therefore, Event Analysis is the natural and necessary companion to the development and improvement of standards. MRO generally supports NERC's efforts in the Event Analysis area. MRO would like to see a more accelerated roll-out and training for root cause analysis and defining what constitutes a complete and rigorous Event Analysis. Additionally, MRO is generally concerned that the past compliance and enforcement approach has squelched more opportunities for sharing lessons learned. Perhaps this can be discussed in the future to find alternatives to share lessons learned more quickly while maintaining the integrity of the compliance and enforcement program.

5. Improve and Clarify Roles

MRO suggests that NERC consider a standard business model to drive results, clarify roles, and reduce duplication. For example, MRO supports a "franchisor-franchisee" type business model where the roles are clearly defined through the model. NERC, as the "franchisor," leads the industry for standards development, trains and equips the Regional Entities (as "franchisees" via the delegation agreement), and provides oversight to assure uniformity and fairness. As "franchisees," the Regional Entities are essentially the "front lines" to the Registered Entities who handle all the "day to day" matters. NERC's role in the field would be dedicated to large scale system events, effective oversight, and assuring more uniformity through training and procedures to support the Regional Entities. This type of business model can leverage both a North American view through NERC and a more local view through the Regional Entities.

Find Fix, Track, and Report Initiative

MRO supports and has actively participated in the Compliance Enforcement Initiative which includes the "Find, Fix, Track and Report" or FFT process. As of January 1, 2012, MRO has accounted for almost 20% of the 325 FFT remediated issues filed by NERC and the Regions at the Federal Energy Regulatory Commission.

MRO believes that the FFT Process appropriately recognizes that all possible violations must be recorded and addressed by the Registered Entity. In order to satisfy MRO's public trust obligation, MRO conducts an independent assessment of risk on all possible violations, even the violations that appear to be "minor" ones, and ensures that all instances of noncompliance are mitigated. This reduces risk and improves BPS reliability. If MRO determines that the violation is a "minor" one, it manages the violation through the FFT process. The FFT process benefits the ERO by scaling the record requirements with the actual risk posed by a possible violation, thereby allowing MRO to spend more time on material matters and less time on "minor" and administrative violations which pose little risk to the BPS.

The FFT process, as Phase One of the Compliance Enforcement Initiative, is a step in the right direction, but more needs to be done. MRO supports the ERO's efforts underway to develop Phase Two of the Compliance Enforcement Initiative which should provide better alignment between the materiality and the significance of instances of noncompliance, with the enforcement process being reserved for matters material to the reliability of the BPS. This approach should also result in additional cost savings for Registered Entities by reducing paperwork and administrative burdens related to mitigation and external reporting.

The success of the ERO lies with realizing that the hallmark for reliability is not that interconnections are error free, but that those errors and other operating anomalies won't create a cascading outage. The technical regulatory regime must recognize this reality and allow the industry to correct the small matters outside of enforcement as part of its commitment to "operational excellence." Key features of "operational excellence" are strong corrective action programs and embedded risk controls (i.e. internal assurance). The regulatory regime should align with the drive to "operational excellence." However, without an alternative to the full enforcement process where everything is processed administratively regardless of actual risk posed by the individual facts and circumstances, we will remain focused on achieving compliance through enforcement only, rather than driving "operational excellence."

In summary, MRO continues to strongly support the NERC Compliance Enforcement Initiative and the next phases must focus on "significance" and reducing end-to-end compliance costs for Registered Entities.

Generator Operator (GO)/Transmission Operator (TO) Issues

MRO believes that the careful application of NERC's existing registration principles and criteria would resolve the issues resulting from the Cedar Creek and Milford Wind proceedings. MRO is concerned that the failure to follow existing registration principles and criteria will result in an improper Transmission Operator (TOP) designation which will cause confusion and degrade the reliability of the bulk electric system. MRO believes the Commission was clear that the Cedar Creek and Milford Wind proceedings were to be narrowly applied to the particular situation and therefore, NERC should not pursue further efforts on this matter and instead, provide guidance and tighter oversight on the existing registration criteria.

For example, in its Statement of Compliance Registry Criteria (Revision 5.0), NERC states it will apply certain principles to determine whether an entity meets the registration criteria. The first principle notes "NERC must identify the owners, operators, and users of the bulk power system who have a material impact on the bulk power system through a compliance registry. NERC and the Regional Entities will make their best efforts to identify all owners, users and operators who have a material reliability impact on the bulk power system in order to develop a complete and current registry list." See NERC's Statement of Compliance Registry, Version 5.0 (emphasis added). The significance of "material reliability impact" is clear, not only from its repetition in the principles for registration criteria, but also because the lack of a material reliability impact can result in a Registered Entity being excluded from a functional designation. A Registered Entity which meets the criteria for various functions may nevertheless be excluded from registration by the Regional Entity, if the Regional Entity "believes and can reasonably demonstrate to NERC that the bulk power system owner, operator, or user does not have a material impact on the reliability of the bulk power system."

Moreover, MRO is concerned about the unintended consequences that may flow from improper registration. In the MRO Region, these entities as Generator Owners (GOs), Generator Operators (GOPs) and Transmission Owners (TOs) have obligations to communicate with the TOPs which operate the transmission system connected with the long generation lead. If these GO, GOP and TO entities are improperly classified as TOPs, those communication obligations

would become an obligation to communicate with itself. This was certainly not the intent of registration. The loss of communication would be an unintended consequence of registering an entity with a single long generator lead as a TOP and it would adversely impact reliability.

Going forward, MRO believes that concerns such as those raised by Cedar Creek and Milford can be avoided through proper application of the existing NERC Registration Criteria. MRO believes that Standards Project 2010-07 (Generator Requirements at the Transmission Interface) is a step in the right direction to resolving the matter in the future.

Rules of Procedure Changes

MRO is pleased with the work that has been done to improve the Event Analysis process. The Event Analysis process recently developed by collaborative work of the Operating Committee and the Planning Committee though the Event Analysis Working Group provides expectations and clarity about the categories of events to be reviewed and the level of analysis required. MRO believes that this work reflects NERC's role as a learning organization. It is important to allow future events to continue to shape and refine the Event Analysis process leading to continuous improvement by the ERO.

However, embedding this fundamentally technical analysis process in the Rules of Procedure, a legal model, makes cementing the process more important than having a process with appropriate flexibility to ensure robust lessons learned - lessons which have a direct, positive impact on reliability. Inclusion in the Rules of Procedure may limit future legitimate avenues of inquiry in an Event Analysis due to the restrictive and legal nature of the Rules of Procedure. Moreover, inclusion in the Rules of Procedure will certainly stifle the evolution and improvement of the Event Analysis process due to the processes required to change Rules of Procedure. In short, it's too early to memorialize the Event Analysis process in the Rules.

MRO encourages the Board of Trustees to leave the Event Analysis process in a collaborative environment so that the goals of real and robust lessons learned are met through the event analysis process and the reliability of the bulk power system is improved. In its comments on the Rules of Procedure submitted to NERC, MRO has suggested that to the extent NERC and the Board of Trustees desire to define the major event and investigative processes conducted by NERC and FERC, the change to the Rules of Procedure should focus on Section 807 – Analysis of Major Events and Appendix 8 – Blackout and Disturbance Response Procedures. The Event

Analysis process for lesser events conducted by the Regional Entities and Registered Entities should simply be referenced.

Therefore, MRO recommends that the Rules of Procedure exclude detailed Event Analysis process at this time. MRO supports a defined, transparent Event Analysis process so Registered Entities have clarity about expectations and the public has assurance that events will be analyzed in a timely, thorough manner.

Midwest Reliability Organization appreciates the NERC Board of Trustees consideration of its comments.

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
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NPCC Board of Directors Policy Input to the February 8, 2012 NERC Member Representatives Committee and February 9, 2012 NERC Board of Trustees Meetings

1. ERO Enterprise Strategic Planning

a. NPCC supports the transitioning of the ERO's reliability enhancement strategy from an intensive document-based compliance enforcement regime, to a risk-based reliability performance focused approach included in the draft Strategic Plan

b. NPCC recommends the expeditious development of risk-based standards, the expansion of reliability performance focused compliance efforts, increased ERO Enterprise-wide staff training and informational workshops for industry, enhanced communications and tracking of applications of lessons learned from a robust events analysis program, development of meaningful reliability metrics based on technically sound reliability assessments, and the efficient leveraging of NERC, Regional Entity, and industry resources to achieve these objectives

2. Find, Fix, Track and Report Initiative

a. NPCC continues to support implementation of the Find, Fix, Track and Report (FFT) procedure as a forward advancement in NERC's continuing efforts to improve the efficiency and effectiveness of the ERO's compliance processes for Possible Violations that pose lesser risks to the Bulk Power System

b. NPCC suggests that NERC use the six month status report filing to also recommend that FERC act to approve FFTs filed in the future, in order to document regulatory closure with regard to mitigated Possible Violations

c. NPCC recommends that NERC accelerate its auditor training and industry informational webinars and workshop programs to introduce an FFT approach to the auditing process in the last quarter of 2012

3. Generator Owner (GO)/Transmission Owner (TO) Issues

a. NPCC supports limiting applicability of FAC-001 Interconnection Standard to Generator Owners interconnecting a third party facility to the GO's existing facility

b. NPCC also supports the limited applicability of FAC-003 for those GO/GOPs with interconnections greater than 1 mile, and the clarifying language in PRC-004 for coordination of protection related to generating facilities

c. NPCC continues to recommend that requiring GO/GOPs to register as TO/TOPs is not the appropriate mechanism to address any potential reliability gaps at the interface

4. Rules of Procedure Changes

a. NPCC supports the removal of some of the administrative details from the ROP and recommends further elimination of such implementation specifics to allow for innovation and operational efficiencies within a consistent, continent-wide context

b. NPCC strongly supports the ROP changes which accommodate an all independent member Hearing Body for compliance matters

5. Expedite Dissemination of Technical Information and Lessons Learned from Event Analyses and Investigations

a. NPCC is concerned with the delay in disseminating to the industry potentially critical lessons learned from significant events that are under multi-party investigation and recommends that NERC prioritize the early release of such reliability related information

b. NPCC recommends that NERC expedite the development of processes that would allow for the confidential sharing of detailed technical data associated with system events to those industry experts that could utilize such information to effectuate reliability enhancements in other registered entities

Approved by NPCC Board of Directors
At its February 1, 2012 Meeting

National Rural Electric Cooperative Association (NRECA)
Policy Input to the NERC Board of Trustees (BOT)
February 2, 2012

NRECA appreciates the opportunity to provide policy input to the NERC BOT regarding several issues that will be discussed at the February 8/9 MRC and BOT meetings.

Update on ERO Enterprise Strategic Planning

- Stay focused on core mission – standards development and compliance/enforcement.
- Maintain ANSI accreditation.
- Don't get distracted by smaller issues that don't impact BES reliability.
- Implement the FFTR/Compliance Enforcement Initiative Phases 2 and 3 as soon as possible.
- Work with industry on standards development process revisions and further focus and implementation of results-based standards.
- Support industry's efforts to complete work on the CIP standards.
- Take steps necessary to gain FERC approval of the recently approved Phase 1 BES definition and provide needed support to the drafting team for completion of Phase 2.
- Take steps needed to focus CANs on providing guidance and not expanding or interpreting standards outside the standards development process
- Increase frequency and depth of training for auditors employed or contracted by the Regional Entities. Offer stakeholders the opportunity to receive the same training.
- Ensure that work on the Adequate Level of Reliability (ALR) definition is completed in a timely manner and that the result is a product that provides stakeholders appropriate criteria for standard development.
- Continue to support the key stakeholder-driven roles of the Standards and Compliance and Certification Committees. Both committees are critical to NERC's role as the ERO.
- NRECA and its members stand ready to contribute to NERC's success in achieving its goals.

Find, Fix, Track and Report Initiative

- Positive first step so far, but more work is required by NERC and the Regional Entities to continue advancing this initiative.
- To date, FFTRs have helped to clear some potential violation backlog issues.
- NRECA is pleased that some minor and/or documentation potential violations have been addressed without a finding of a violation or assessing a penalty.
- NERC and the Regional Entities need to implement Phase 2 and 3 as soon as possible to provide increased material benefit to stakeholders.

Generator Operator/Transmission Operator Issues

- BOT should approve SDT work product on the GO/TO issues (Project 2010-07) and quickly file it with FERC for regulatory approval.
- Strong industry support for Project 2010-07 demonstrated in ballot results.
- No reliability issues identified that would necessitate the registration of GO/GOPs as a TO/TOPs.
- NERC directive not needed to resolve issues that are being addressed today through Project 2010-07.

Rules of Procedure

- For all future ROP changes proposed by NERC for stakeholder comment, there must be detailed evidence and support provided for the proposed changes prior to the 45-day comment period. Without this evidence and support it is challenging for industry to understand why changes were proposed and it does not help industry to provide constructive and targeted comments on such changes.
- NRECA is willing to work with NERC to develop a needed transparent process for NERC to use when addressing industry comments on ROP issues.
- Specific language should not be included in the ROP making Events Analysis mandatory. These issues can be properly handled outside of NERC's governance documents.
- NRECA remains strongly opposed to the NERC proposal to increase from 10 to 50 the number of NERC members required to request an ROP modification. We understand the ROP is being changed to align with the NERC Bylaws. Instead, NERC should consider if the Bylaws should be changed to align with the ROP.

Standard Development Process Improvements

- NRECA is a signatory to the "February 2, 2012 Trade Association Standards Development Principles" policy input comments that are being submitted separately from this document.
- NRECA strongly believes that NERC and industry need to first identify problems/causes of inefficiencies in the standard development process and then develop responsive solutions. Any changes/improvements must be in response to identified problems/causes, and not in response to unsupported assertions or anecdotal reports.
- NRECA believes that standards development process improvements need to be addressed in a collaborative manner in order to effectively address the problems experienced to date. The MRC along with a working group it will form should endeavor to organize the effort and define the high-level goals, priorities and expectations for standard development process revisions. The work product from this effort will guide the NERC SC and its Process Subcommittee in their efforts to more fully develop a revised standard development process based on an assessment of problem

causes, while maintaining credible components of the current standard development process.

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January 31, 2012

Via Electronic Mail
John Q. Anderson, Chair
NERC Board of Trustees
c/o Dave Nevius, MRC Secretary
dave.nevius@nerc.net

Re: Policy Input to NERC Board of Trustees

Dear Mr. Anderson,

Reliability*First* Corporation ("Reliability*First*") appreciates your request for policy input on the Find, Fix, Track, and Report Initiative and the Rules of Procedure Changes in your letter dated January 17, 2012. Given that the Find, Fix, Track, and Report Initiative and the NERC Rules of Procedure are important matters that impact Reliability*First*'s day-to-day operations, Reliability*First* respectfully provides the following input for the consideration of the NERC Trustees. These comments represent the views of our organization and are not intended to necessarily reflect those of our collective stakeholders within the Region.

A. Find, Fix, Track and Report (FFT) Initiative

Reliability*First* believes that the FFT initiative is a watershed moment in the evolution of the ERO regulatory model. Although the FFT is labeled as an "Enforcement Initiative," we consider the FFT as the first major initiative to review the data obtained during the first four plus years of mandatory enforcement, to determine whether the value gained (increased reliability) as measured against the expenditure of resources and time by the Regions and Registered Entities made sense and whether that gain in reliability could be obtained in a more effective, efficient and timely manner, or, perhaps, certain enforcement actions, and subsequent registered entity actions, produced no gains in reliability at all. Reliability*First* hopes that programs like FFT will be implemented over time across all ERO programs.

Reliability*First*, consistent with the stated goals of the FFT initiative, has utilized the FFT where the facts and circumstances warrant (approximately 50% of our Regional enforcement actions are now resolved through use of the FFT) which has further improved our ability to focus time and resources proportionately based on the risk posed by the violation. Reliability*First* continues to be a steady and significant contributor to the total number of FFTs NERC files each month with the Commission. Reliability*First*, however, cautions both NERC and the Regions that the FFT is a means not an end; placing too much emphasis solely on FFT *volume* may have a detrimental effect on responding to more serious violations. We believe all would agree that such an outcome is counter to the stated goal of the FFT, namely the saving of Regional and Registered Entity resources on minor matters in order to free those resources up to work on the more important and serious matters.

The brevity of the information necessitated by FFT spreadsheet format makes it critical that clear, concise and comprehensive information is given detailing the nature of the violation, the risk posed and the mitigating activities undertaken, making it clearly understandable about why the decision was made to utilize the FFT as the final disposition of the issue. This is important to NERC and FERC, each of which provides oversight of the use of FFT, and also to other Registered Entities so that they can be assured of equitable treatment under this program. If on its face, an issue seems complex and serious, inclusion in the FFT may create confusion or questions absent a clear and sufficient explanation when the FFT is submitted. Furthermore, again to avoid confusion and conflict, we must address the misconceptions we run into with Registered Entities, such as an FFT designation being a prerequisite to receive a zero dollar penalty is false (zero dollar penalties are available across all FFT/NOP filing mechanisms) by openly communicating with Registered Entities and/or FERC.

Reliability*First* supports the identified Phase 2 of the FFT initiative, namely the use of auditing teams to identify FFT candidates immediately at time of issue detection. However, Reliability*First* believes that the subsequent savings in time and resources, either at the Regional or Registered Entity level, although greatly appreciated by all, is again a step in the right direction but should not be the end point. For example, future initiatives should include provisions to exercise judgment and discretion and decline to pursue those matters that are "technically" violations but clearly have no impact on reliability.

Another future initiative, and one that we feel is essential, is to invest time in reviewing the nature and risk and harm posed by the issues being filed in the FFT (and filed through other disposition methods prior to the FFT) to determine whether certain standards or requirements are effectively contributing to reliability. Similar to the valuation of whether certain enforcement actions are contributing to reliability, the same valuation activity should occur for individual standards and requirements. Those that do not contribute to reliability effectively should be examined for modification, addition or deletion. Continued focus on enforcement or auditing initiatives alone will not solve the ultimate problem; if some standards and requirements have no appreciable impact on reliability and remain in force, Registered Entities will incur costs to comply.

It is incumbent upon the ERO and the Regions to provide feedback to industry as to the measured value to reliability that all ERO and Regional activities provide.

B. Rules of Procedure Changes

The NERC Rules of Procedure (RoP) and its Appendices are critical documents to the ERO enterprise. These documents govern the Regions' day-to-day work while simultaneously providing clarity and guidance to the Registered Entities of the various ERO compliance processes and requirements. Consequently, NERC should limit modifications to these important documents to only those instances where the modification is necessary to both clarify and add greater efficiency to NERC and the Regions' work. The comments that follow are based upon the proposed modifications to RoP that were posted and publicly available at the time of this writing.

After analyzing and discussing the proposed modifications with NERC staff, other Regions, stakeholders, and various industry trade associations, Reliability*First* does not believe that the proposed modifications meet this important criteria (other than the limited revisions that are necessary to address pending FERC orders). More fundamentally, Reliability*First* respectfully question the need to, at this time, open and revise numerous rules impacting and relating to the hearing process given collective inexperience of both

NERC and the Regions with the hearing process to date.[1] We further question the advisability of incorporating the elements of the event analysis process in the Rules at this time.

Reliability*First* suggests that the Board consider allowing NERC staff and the Regions to obtain experience with both the hearing process and related processes so an understanding of any current rule deficiencies, to the extent that there are any, may be better identified and future revisions may be developed simultaneously and considered and discussed from a more informed basis. We provided specific comments related to this topic in a public response we made to NERC during the open comment period for these revisions.

We strongly support the events analysis process effort that NERC has undertaken. In fact, Jacquie Smith of our staff chairs the group charged with developing and implementing it. However, we feel the process is not yet mature enough to incorporate into the Rules of Procedure. Seeking formal FERC approval of the process elements via the Rules will complicate the need to make necessary adjustments as we employ and learn more about this important process. We also believe that industry implementation of the process should remain voluntary as opposed to a mandatory requirement in the Rules. For these reasons, we ask the Board to carefully consider making the proposed changes at this time.

C. Conclusion

Reliability*First* appreciates the NERC Board of Trustees consideration of Reliability*First*'s suggestions. Although Reliability*First* does maintain serious concerns about proceeding with the currently proposed rules, Reliability*First* would like to note its appreciation for NERC staff's outreach and hard work to date in attempting to develop and revise the proposed Rules of Procedure. However, at the end of the day, Reliability*First* believes that there is presently no compelling reason to immediately proceed with any of the revisions at this time (other than those limited revisions that address FERC orders).

If you have any questions, please do not hesitate to contact me.

Very truly yours,

RELIABILITY*FIRST* CORPORATION

Timothy R. Gallagher
President & CEO

cc:
L. Jason Blake – Reliability*First* Corporation, General Counsel
Gerry Cauley – North American Electric Reliability Corporation, President & CEO
Reliability*First* Corporation Board of Directors

[1] Reliability*First* is unaware of any Region that has completed all steps involved in a hearing and, to the best of Reliability*First*'s knowledge; only one Region (Reliability*First*) has entered the Comment stage of a hearing.

NERC Sector 4 – Federal or Provincial Utility
Policy Input to NERC Board of Trustee Request of January, 2012
February 2, 2012

The North American Electric Reliability Corporation (NERC) Sector 4 members appreciate the opportunity to provide written input to the NERC Board of Trustees. Sector 4 held a conference call among its members to discuss the request for policy input and shared several emails to coordinate this input.

More than five years have passed since NERC's certification as the Electric Reliability Organization ("ERO"), and it is clear that – amidst the many milestones achieved – NERC is confronting a broad array of challenges. For some time, participants at NERC have engaged in a series of discussions and initiatives to streamline the ballooning workload which NERC currently shoulders and to identify the principal priorities which NERC ought to address.

In the spirit of these endeavours, Sector 4 members offer support for focusing NERC's activities on its core responsibilities and objectives, and recommend measures for ensuring NERC remains capable of functioning effectively as an international standard-setting organization with the backing of its Canadian stakeholders.[1]

We offer the following principles for a vision of NERC looking ahead:

A Focus on Standards Development

- NERC's paramount focus is delivering on its core responsibility of developing clear, robust and cost-effective reliability standards for the Bulk Electric System ("BES").
- Industry stakeholders are able to participate actively and effectively in the NERC standards development process, and are not overwhelmed or unduly pressured by unreasonably stringent project timelines or an impracticably high volume of concurrent standard projects.
- Participants are focused on developing technically excellent, risk-based and results-based standards aimed at the greatest reliability risks on a timely, but not an unnecessarily accelerated basis.
- Time set aside for improving existing standards is roughly commensurate with that spent developing new standards.
- NERC will effectively triage pending and ongoing standard projects.
- Concurrent projects on different versions of the same standard will be avoided.
- Ad hoc and/or standing initiatives do not distract NERC from fulfilling its primary responsibilities in standards development.

An Effective International Standard-Setting Body

- NERC functions effectively as an independent, international standard-setting body, free from the exertion of undue influence or pressure by any single governmental authority, and in a manner consistent with the August 2005 *Bilateral Principles For An Electric Reliability Organization That Can Function On An International Basis*.

[1] This policy input represents the views of Sector 4 members exclusively. However, Sector 4 members wish to acknowledge contributions from the Canadian Electricity Association to this document.

- NERC achieves an effective balance in not imposing excessive requirements on entities subject to the jurisdiction of one governmental authority when seeking to fulfill the directives of another authority.
- NERC respects the boundaries of its enforcement authority (or lack thereof) in Canadian jurisdictions.
- NERC continually pursues, measures, and reports on actions to improve its effectiveness and efficiency.
- Applicable governmental authorities remain mindful of the potential impacts of their directives on other North American jurisdictions.
- ERO resources are efficiently managed and allocated, with resource levels reflecting corresponding priority levels for program areas.
- Clarity exists regarding the separation of functions and responsibilities between NERC and other organizations such as the North American Transmission Forum, such that duplication of efforts is avoided.

Non-Standards Activities

- The NERC ROP are exercised in a manner which does not seek to impose reliability obligations on registered entities outside of the standards process.
- Applicable governmental authorities, NERC and stakeholders give careful consideration to resource constraints and prospects for "mission creep" when new ad hoc and/or standing initiatives are contemplated.
- Ad hoc and/or standing initiatives do not distract NERC from fulfilling its primary responsibilities in standards development.
- NERC as the ES-ISAC is able to share timely and actionable information to bulk power system users, owners and operators in the event of an imminent security incident.
- Canadian and U.S. authorities consult and coordinate in the sharing of timely and actionable threat information with each other, NERC and industry stakeholders.

On behalf of the NERC Sector 4 Members -
Sincerely,

Anthony H. Montoya
Chief Operating Officer
Western Area Power Administration

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SERC Board of Directors Policy Input to NERC
February 2012

SERC Reliability Corporation (SERC) continues to be pleased with and supportive of the continued advances being made by the Electric Reliability Organization (ERO). The SERC Board of Directors appreciates the opportunity to provide policy input to NERC for the February 2012 Board of Trustees and Member Representatives Committee meetings.

ERO Enterprise Strategic Planning

- SERC is generally pleased with the strategic focus that NERC and the Regional Entities have placed on implementing the ERO model. Maintaining the proper balance of independence from stakeholders with connection to stakeholders needs to be a continuous objective.
- While recognizing that NERC and the Regional Entities are nine different corporations involved in various activities, SERC believes that joint strategic planning among NERC and the Regional Entities, particularly for statutory responsibilities, is an important starting point. While joint strategic planning is good, important and necessary, SERC encourages NERC and the Regional Entities to work closely together to develop operational plans that will more consistently and efficiently deliver execution of ERO responsibilities. .
- SERC representatives will look forward to hearing about NERC's 2012 goals in the Board of Trustees committee meetings. SERC desires for its corporate goals to be aligned and coordinated with NERC.

Find, Fix, Track, and Report Initiative

- FFT has been a positive example of a timely and effectively-deployed ERO program. While there are opportunities for improvement, the fact that the initial phase of FFT was scoped, developed and delivered in less than a year is worthy of acknowledgement and praise.
- The current deployment of FFT has had limited impact on reducing the registered entity and regional entity compliance and enforcement staff work load because the level of review and detail required to assess, substantiate and defend the election of the FFT approach has been on the order of what is required for more substantial matters. SERC would hope that this work load would be streamlined as FFT matures.
- Additionally, building upon the initial deployment of FFT to the enforcement function, SERC recommends the deployment without delay of FFT concepts to the audit function, Audit teams need the ability to find, fix, track and report appropriate items which are observed during an audit. While the initial phase of FFT use in enforcement deserves celebration, much work remains to fully focus scarce resources on those reliability issues which have the greatest impact and risk. The deployment of FFT in all phases would allow the redeployment of scarce resources to the reliability issues and have the greatest impact.
- SERC members appreciate the additional FFT outreach efforts that have been extended. Stakeholders would like to continue to see more outreach and transparency on identifying items which would qualify. If we as an industry want the FFT process and other such processes to be used to improve and maintain the reliability of the grid, then the stakeholders need to understand clearly the rules and criteria.

SERC Reliability Corporation

Generator Operator (GO)/Transmission Operator (TO) Issues

- The current GO/TO issues are the symptom of a bigger problem. That is, the ERO's methods for administering reliability requirements are founded upon the application of reliability standards and the associated requirements to pre-defined reliability functions. Until such time as the ERO's methods recognize the application of individual reliability requirements to individual registered entities, unnecessary application of reliability requirements to some registered entities will continue to exist.
- The administrative burden to achieve such a method of application could be extremely high. NERC should consider conducting an analysis of the cost to implement a registration process and standards application method such that individual entities are required to demonstrate compliance only for those reliability requirements which are directly applicable to that entity.
- Alternatively, NERC should develop more specificity and granularity in the "Applicability" section of the standards. Standards should not apply broad requirements to reliability functions just because they "might" be responsible for a certain requirement in certain business configurations.

Rules of Procedure Changes

- Generally, NERC's Rules of Procedures have a significant focus on implementation details, and the proposed changes continue that approach. Rules of Procedure which contain detailed process steps constrict the ability of registered entities and regional entities to cut through red tape and bureaucracy and focus on the important matters. Often when changes are made, unproven implementation details are included. While hardwiring implementation details in the Rules of Procedure can provide process certainty, it also limits ability to flexibly adjust to changing conditions and often stifles innovation and improvement. As NERC modifies its Rules of Procedure, consideration should be given to including in the Rules of Procedure authorizing program/activity definitions, scope, objectives, and high level roles and responsibilities. Implementation details can be placed in a more flexible program guide that might be modified more easily. To increase understanding of the broader Rules of Procedures, the initial program guide could still be developed and published in parallel to the Rules of Procedure changes.

Southwest Power Pool Regional Entity
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Little Rock, AR 72233

SPP RE Board of Trustees' Policy Input to the NERC Board of Trustees February 3, 2012

The Southwest Power Pool Regional Entity (SPP RE) respectfully submits the following recommendations regarding the Compliance Application Notice (CAN) development process for consideration by the NERC Board of Trustees.

Background

The SPP RE is supportive of the purpose of CANs: to enhance consistency among auditors across the Electric Reliability Organization (ERO) and provide industry with transparency for audit preparation and development of effective internal controls. The SPP RE also recognizes and appreciates NERC's efforts to-date to improve the CAN development process. Without diminishing the oversight role of NERC, the SPP RE recommends greater involvement of the eight regional entities in the development of CANs throughout the development process. The regional entities can offer their detailed knowledge of the standards, technical expertise, and broad experience with registered entities. The SPP RE submits the following recommendations.

Recommendation

1. Involve the regional entities to identify points of confusion or error as the CAN is initially drafted prior to submittal to the industry for comment. The regional entities can also assist NERC in addressing entity comments and ensuring technical accuracy as the CAN is finalized.

2. Ensure all comments submitted by the industry and the regions are evaluated as the CAN is developed. The recommended improvement includes automated entry of comments into a database similar to how standards comments are received, acknowledgement of comments received, and posting of comments upon closing of the comment period to allow submitters to confirm their comments have been received.

3. Afford the regional entities a longer period of time to review and comment on the draft CAN prior to submission to the industry for comment. The current five day period is too short.

4. Permit the regional entities an opportunity to review and voice technical concerns to the near-final CAN and NERCs response to submitted comments following NERC's incorporation of industry comments. A review period of two weeks is recommended.

MEMORANDUM

TO: Dave Nevius, Secretary
NERC Member Representatives Committee

FROM: Tim J. Arlt
John DiStasio
Bill Gallagher
John Twitty

DATE: February 2, 2012

SUBJECT: Response to Request for Policy Input

The MRC's State and Municipal and Transmission Dependent Utility Sectors (SM-TDUs) appreciate the opportunity to respond to the January 17, 2012 letter from NERC Board Chairman John Q. Anderson to Mr. Scott Helyer, acting in his capacity of the Chairman of the NERC Member Representatives Committee (MRC) requesting policy input on topics to be discussed by the NERC MRC and the NERC Board of Trustees at the February meetings.

This response addresses all four topics raised in Mr. Anderson's January 17 letter:

- Update on ERO Enterprise Strategic Planning
- Find, Fix, Track and Report Initiative
- Generator Operator (GO)/Transmission Operator (TO) issues
- Rules of Procedure Changes

1. Update on ERO Enterprise Strategic Planning

SM-TDUs strongly support the three strategic goals proposed by NERC in the *DRAFT Electric Reliability Organization Strategic Plan 2012-2015* (MRC Agenda Item 6, Attachment 1, page 3). It is our hope and expectation that NERC's draft Strategic Goals will focus the ERO Enterprise on its statutory mission, which is to establish and enforce reliability standards that provide for reliable operation of the bulk-power system. To achieve this mission, we agree that NERC must focus on: (1) Standards and Compliance, (2) Risks to Reliability, and (3) Coordination and Collaboration. These goals appropriately recognize the need to balance NERC's obligation to develop and enforce compliance with reliability standards with its responsibility to remain a learning

organization that provides effective feedback to the industry on the reliability risks we face in the planning, design, operation and maintenance of the bulk power system. The SM-TDUs overwhelmingly agree that greater efficiencies in NERC's standards development and enforcement process can be achieved through collaboration between NERC, the regions and industry stakeholders. NERC has also made great strides toward restoring the appropriate balance between enforcing the reliability standards and implementing initiatives aimed at fostering reliability excellence through learning. Most notably, the Find, Fix, Track, and Report initiative (discussed below) should enable the industry to resolve minor violations of reliability standards efficiently and effectively through mitigation. We encourage NERC to continue to develop ways to provide feedback and lessons learned to the industry in a manner that fosters greater collaboration going forward. However, much work remains to be done.

We also believe that a roadmap should be developed that provides more detail with respect to how NERC expects to achieve these priority goals over the course of the year.

Draft Strategic Goal 1a) provides that the ERO Enterprise will:

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.

The SM-TDUs believe that achieving this goal, which might be better framed in terms of minimizing risk of instability, uncontrolled separation or cascading outage (recognizing some interruptions of the bulk power system may be unavoidable), is vital to ensure reliability excellence. We are concerned that the timelines and complexity embedded in the existing standard development process threatens our ability to achieve it. Accordingly, the SM-TDUs support an effort to reform the standards development process by making it more streamlined, while retaining the stakeholder involvement necessary to ensure that the resulting standards account for the wide diversity among registered entities and how the bulk electric system is operated and planned. To that end, we endorse and incorporate by reference the standards development principles and recommendations developed by industry trade associations that provide a starting point to improve the NERC standards development process.[1]

[1] See the February 2, 2012 *Trade Association Standards Development Principles*, submitted separately. The Trade Associations supporting these principles and recommendations include the American Public Power Association, Edison Electric Institute, Electric Power Supply Association, Electricity Consumers Resource Council, Large Public Power Council, National Rural Electric Cooperative Association, and Transmission Access Policy Study Group.

Draft Strategic Goals 1b) and 1c) provide that the ERO Enterprise will:

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.

The SM-TDUs believe that striking the appropriate balance in these goals with NERC's commitment in Goal 3 to operate as a transparent, collaborative, efficient, and cost-effective enterprise will result in a more common sense and sustainable compliance regime, and will ultimately result in greater reliability than a regimen focused solely on bringing down the enforcement hammer. We also firmly believe that *promotion of a culture of reliability excellence*, as set forth in Goal 2c), must have equal status with *promotion of a culture of compliance* (Goal 1c).

As noted above, NERC has implemented some important initiatives in support of its compliance and enforcement goals, such as FFTR. We also encourage NERC to ensure that auditors determine compliance based on whether a registered entity achieved the reliability objectives set forth in the standard, as opposed to the manner in which it achieved compliance. In particular, the audit approach adopted by a regional entity should focus on whether the registered entity is achieving the specific reliability objectives set forth in each requirement on a sustained basis. Experience shows that a narrow, prescriptive reading of reliability requirements, measures and compliance elements by auditors can elevate the development and preservation of documentation of compliance above other activities that are far more vital to actually ensuring reliable operations.

2. Find, Fix, Track and Report Initiative

SM-TDUs applaud NERC for its September 30, 2011 FERC filing and implementation of its proposal to exercise discretion in dealing with lesser risk enforcement matters. Under this initiative, minor administrative, documentation-related, and other violations that pose a lesser risk to reliability need to be addressed quickly and simply, so that NERC, the Commission and the industry can refocus their attention on actual and potential reliability issues that pose a significant risk to reliable operation of the bulk power system. SM-TDUs joined with others in the industry in strongly urging the Commission to accept NERC's petition as a well-designed first step in recognizing a significant and growing problem of resource misallocation in the ERO compliance and enforcement program.

While developing and initiating FFTR was a major step forward, more needs to be done to make it truly effective in achieving the efficiencies that are our shared goal for this important effort. Analysis of the initial months of FFTR implementation reveal significant differences among regions in the application of FFTR. While a number of factors could contribute to these differences, we are concerned that the widely disparate percentages of application of FFTRs versus NOPs among the regions signals inconsistency in the criteria being used by various regions in assessing eligibility for FFTR. As NERC moves toward submission to FERC of its promised six-month report on FFTR, it should focus on mechanisms to achieve wider use and greater consistency in the application of FFTR across the NERC footprint.

Beyond fuller, fairer and more consistent application of FFTR, SM-TDUs support extension of the risk-based approach reflected in FFTR to the audit context. As envisioned in the FFTR filing, NERC should focus on training auditors so that FFTR decisions can be made in the field, thereby increasing the savings and efficiencies for all involved, while freeing up registered entity resources to focus on reducing risks to reliability. Smarter, more risk-informed auditing should be an integral part of the next stage of NERC's Compliance Enforcement Initiative.

3. Generator Operator (GO)/Transmission Operator (TO) Issues

SM-TDUs draw a number of lessons learned from the controversies that have arisen with respect to Generator Owners and Operators (GOs and GOPs) that also operate BES transmission voltage interconnection facilities, thereby leading NERC to register these entities as Transmission Owners (TOs) and/or Transmission Operators (TOPs). As an initial matter, we offer no opinions as to the Compliance Filings and other directives issued by FERC in its Milford and Cedar Creek orders, except some regret that NERC and its stakeholders were unable to reach consensus on both the nature and extent of the potential reliability gap(s) and the procedural mechanisms available to address these gaps before so much ink had been spilled.

As a starting point, the Ad Hoc GO-TO Task Force did a very good job defining the nature of this potential reliability gap, including a list of specific Requirements that should be applicable to GOs/GOPs that own and operate BES voltage interconnection Facilities. The Ad Hoc GO-TO Task Force's work was completed in November 2009. Unfortunately, NERC and industry resource constraints led the Standards Committee to make a difficult decision in early 2010 to delay initiation of formal development work on Project 2010-07, Generator Requirements at the Transmission Interface. The GO-TO standard drafting team (SDT) sought and received approval to begin development on an informal basis, until full support by NERC staff could be provided beginning in 2011. Since that time, the SDT moved expeditiously to reach industry consensus in support of a technically robust set of revised reliability standards, in which specific existing Requirements have been revised to extend their applicability to GOs and GOPs that own certain transmission voltage interconnection Facilities. This work appears to be nearly complete.

Most notably, the SDT developed and publicly posted a March 2011 *White Paper*, followed by a June 2011 *Background Resource (White Paper)* document. In conjunction with the October 2011 formal posting and comment period, the SDT posted a September 30, 2011 *Technical Justification* document. Each of these documents addressed the applicability-based approach adopted by the SDT, the specific requirements the SDT concluded should apply to generators that own BES voltage interconnection Facilities, as well as those potential requirements that should not apply to GOs or GOPs. Most recently, on December 8, 2011, the SDT posted a revised *Technical Justification Resource Document* in which the SDT reviewed additional standards that NERC staff had proposed to apply to Generator Owners and Generator Operators in NERC *Compliance Process Directive #2011-CAG-001 Regarding Generator Transmission Leads*, as well as standards cited in FERC's *Order Denying Compliance Registry Appeals of Cedar Creek Wind Energy and Milford Wind Corridor Phase I* (135 FERC ¶ 61,241).[2]

To quote directly from the December 8, 2011 Technical Justification Resource Document:

> The SDT reviewed all of these standards and requirements again and continues to find clear and technical reliability-based reasons that support not adding Generator Owner and Generator Operator requirements to the standards. The chart below indicates where else (the Ad Hoc Report, the NERC Directive, or the FERC Order) the standards addressed were discussed. While both the NERC Directive and FERC Orders address specific requirements within these standards, the SDT has found it useful to address each standard as a whole. Often, requirements within a standard, or even from standard to standard, work in concert to ensure that there are no reliability gaps, whereas a review of a requirement in isolation might give the impression that there is gap.

SM-TDUs agree with the SDT's approach and with the systematic and collaborative approach used to resolve technical and other issues. Notably, the SDT has acknowledged that the configuration of certain generator interconnection Facilities may merit either registration of the owner/operator as a TO/TOP or the adoption of a case-specific list of additional Requirements that should be applicable to specific Facilities owned or operated by the GO/GOP. However, these special cases are unusual exceptions to the general rule and should not be included in Reliability Standards applicable to a broad class of entities. The most urgent task for these special cases is to reach agreement as to the technical studies required to determine whether the operation or misoperation of specific Facilities may have a material impact on the reliable operation of the Bulk Electric System. Where studies of specific Facilities and their impact on the BES identify a material impact, case-specific registration by requirement is called for.

[2] Each of these SDT Technical Documents is posted on the Project 2010-07 web page at: http://www.nerc.com/filez/standards/Project2010-07_GOTO_Project.html

4. Rules of Procedure Changes

SM-TDUs recognize that the level of stakeholder involvement in changes to NERC's Rules of Procedure (ROP) is inherently less than in the standards development process. However, we do ask that the Board direct staff to adopt two procedural steps to ensure constructive stakeholder review and efficient use of NERC and industry resources. First, NERC should develop and post a clear rationale for each proposed change to the ROP before, or if necessary, contemporaneously, with the posting of the proposed modification, placing primary emphasis on explaining *why* the change is needed, not just *what* is being changed. Second, we ask that the final version of proposed changes be posted at least ten working days prior to NERC Board meetings, to allow the industry a constructive opportunity to review and if necessary, submit comments prior to Board adoption.

We appreciate that NERC has twice posted (in June and November 2011) different versions of proposed changes to the Rules of Procedure, before posting of the final version on Monday, January 31. We also appreciate the improvements NERC made between the three postings in response to stakeholder comments, particularly the second posting's removal of the previously proposed fines for failure to provide information, and in the final posting, the deferral of consideration of changes to Appendix 8. We also appreciate NERC's decision to defer action on many minor technical changes to the ROP. However, a number of state and municipal utilities continue to voice concerns that proposed section 403 would allow the Regional Entity to appeal the decision of a Regional Entity hearing body. While NERC explained that the Regional Entity hearing body is an independent tribunal that is separate from the Regional Entity Compliance Program, this explanation misses the point that providing the Regional Entity with an automatic right to appeal adds one more layer of cost and uncertainty for the registered entity.

While NERC did not adopt all stakeholder suggestions, these actions left no doubt that NERC seriously considered stakeholder comments. Further, the just-distributed matrix identifying the actions taken and responses to stakeholder comments is very helpful in facilitating an understanding of NERC's thinking, even where we still may not agree with the proposed change. Posting of an earlier version of the matrix in November might have improved the quality of the dialog at earlier stages of the process.

We appreciate the recently extension of time to submit these comments in light of the late posting, but the few days allowed did not permit the full analysis of the final ROP changes and consultation with our members that the invitation to provide policy input on such far reaching changes merits. In the future, we hope that ROP changes to be presented to the NERC Board will be posted sufficiently in advance of the date when policy input is requested so as to afford a full opportunity for industry input.

NERC's recent approval and submission to FERC of Rules of Procedure modifications as part of NERC's January 25, 2012 Bulk Electric System Definition filing

provides a similar case in point. While ROP changes to support processing of case-by-case exemptions were posted for industry notice and comment in October, the final set of ROP changes, which include significant modifications from the previously posted version, were not publicly posted until January 12, 2012, three work-days prior to Board of Trustees January 18, 2012 special meeting to approve the filing.

Thank you for the opportunity to provide this input.

From: Mosher, Allen [mailto:AMosher@publicpower.org]
Sent: Thursday, February 02, 2012 12:04 PM
To: Dave Nevius; Holly Mann
Cc: Dworzak, David; Lawson, Barry R.; Jack Cashin; ggrace@awea.org; Hindin, Barbara; Fama, Jim; Gray, Mark; John Anderson; Nancy Bagot; Kathleen Goodman; Mohre, Dave L.; Metro, Patti; Mitchell, Nathan; Stephen Pelcher; Laura Lewis; Cindy Bogorad; Jonathan Schneider; Bonnie A. Suchman
Subject: February 2, 2012 Trade Association Standards Development Principles

Dear Dave and Holly,

Please find attached to this message Policy Input from the Trade Associations concerning reform to the NERC Standards Development Process. Each of the supporting Trade Associations may supplement the Standards Development Principles attached to this message in our respective comments.

NERC and its core program areas should seek continuous improvement. There is a growing recognition that the standards development process is time-consuming, cumbersome and resource-intensive in ways that are not necessary to ensure clear and effective standards that account for the wide diversity among registered entities and how the bulk electric system (BES) is operated and planned. Significant discussion has taken place at FERC, NERC and with industry over the past year around ways to make such process improvements. As a result of those discussions, the Trade Associations have developed the following principles and recommendations to support an initiative to make significant improvements to the standards development process.

The Trade Associations supporting these principles and recommendations include:

- American Public Power Association
- Edison Electric Institute
- Electric Power Supply Association
- Electricity Consumers Resource Council
- Large Public Power Council
- National Rural Electric Cooperative Association and
- Transmission Access Policy Study Group

Please do not hesitate to contact me should you have any questions.

Allen Mosher
Vice President, Policy Analysis and Reliability Standards
American Public Power Association

NERC Standards Development Process Improvement General Principles and Recommendations

NERC and its core program areas should seek continuous improvement. There is a growing recognition that the standards development process is time-consuming, cumbersome and resource-intensive in ways that are not necessary to ensure clear and effective standards that account for the wide diversity among registered entities and how the bulk electric system (BES) is operated and planned. Significant discussion has taken place at FERC, NERC and with industry over the past year around ways to make such process improvements. As a result of those discussions, the Trade Associations have developed the following principles and recommendations to support an initiative to make significant improvements to the standards development process.

The Trade Associations supporting these principles and recommendations include the American Public Power Association, Edison Electric Institute, Electric Power Supply Association, Electricity Consumers Resource Council, Large Public Power Council, National Rural Electric Cooperative Association, and Transmission Access Policy Study Group.

1. **Areas for Improvement: The standards development process should be improved in four specific areas:**

   - ❖ Clarity on the reliability objectives, technical parameters, scope and the relative priority of the standards project
   - ❖ The drafting process (developing the specific technical content of the standard)
   - ❖ Standards project management and workflow
   - ❖ Formal balloting and commenting

2. **Policy Leadership: The NERC Member Representatives Committee should organize a small group of senior level industry leadership representing a range of stakeholders to meet with the NERC CEO, the chair of NERC Standards Oversight and Technology Committee and the chair of the stakeholder Standards Committee to decide on the approach for making improvements to the four process areas.**

Standards development process improvements need to be strongly aligned with problems experienced to date. The NERC Member Representatives Committee (MRC) should serve as the group to organize such meetings and ensure their success. Decisions will be made by April 1, 2012. These meetings will provide hi-level goals, priorities and expectations to the NERC process subcommittee of the NERC Standards Committee for timely, specific action.

3. **Due Process: As required by the FERC-approved process, standards development process changes must be balloted by stakeholders and approved by the Board. Our goal is final NERC Board of Trustees approval at the November 2012 meeting.**

The Board of Trustees and the MRC will be provided detailed status reports at both the May and August meetings.

Work should be planned and ballots scheduled to ensure that the Board of Trustees has a package for approval at the November meeting.

4. **Technical Excellence: Control of the drafting and technical content of reliability standards should be the responsibility of experienced industry technical experts.**

Both the complexity of planning and operating the BES, and the broad diversity of how the BES is planned and operated across the interconnected network, demand that industry subject matter experts hold this critical responsibility.

NERC and regulatory staff are welcome to contribute subject-matter expertise on the same basis as other experts. Technical writers and legal/compliance expertise have a pivotal role in the standards development process to ensure process efficiencies, clarity and enforceability.

5. **Balloting and Commenting: The standards development process should be closely reviewed to determine areas where it can be condensed to increase efficiency without jeopardizing technical excellence and consensus.**

The current formal comment and ballot process can be significantly improved; however, the balloting process must ensure that individual entities can actively participate, vote and ensure their concerns are addressed.

Efficiency gains can be captured without sacrificing ANSI Principles of openness, transparency, balance of interests, or due process.

6. **Compliance and Enforcement: In tandem with this initiative, both NERC and FERC *must* continue to focus on changing the policies and practices of the compliance and enforcement program area.**

FERC policy and case decisions and the program practices at NERC and each Regional Entity need to continue to pursue reliability risk-based approaches to monitoring and enforcement.

Despite recent initiatives, the costs of paperwork and documentation are high and rising, do not support BES reliability, and their costs in no way correspond to the levels of risks addressed by entities that plan and operate the BES.

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Reliability Standards

NERC Board of Trustees Meeting
February 9, 2012
Herb Schrayshuen, Vice President Standards and Training

RELIABILITY | ACCOUNTABILITY






Generator Requirements at the Transmission Interface (GO/TO)

- Approve standard and supporting documents and direct staff to file with the applicable authorities
  - Reliability Standard FAC-001-1–Facility Connection Requirements
  - Reliability Standard PRC-004-2.1a–Analysis and Mitigation of Transmission and Generation Protection System Misoperations
  - Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for FAC-001-1
  - Implementation plans for FAC-001-1 and PRC-004-2.1a

Purpose of Modifications

- Ensures the responsibility for generator interconnection facilities is appropriately assigned in Reliability Standards
- Addresses registration issues raised by the industry

Ballot Results

- Ballot for Project 2010-07 closed on December 23, 2011 with the following results:
  - FAC-001-1: quorum 88%, approval 90%
  - PRC-004-2.1a: quorum 87%, approval 96%
- Non-binding poll of VRFs and VSLs conducted in January 2012
  - VRFs and VSLs: quorum 78%, approval 93%

Level 1 Appeal FAC-003

- Level 1 Appeal filed by Exelon on January 20, 2012
  - Contends a substantive change was made between the final successive ballot and recirculation ballot
  - Appeal is being considered
  - Appeal process allows 45 days to respond to a Level 1 appeal

Policy Questions

- Should NERC staff delay regulatory filings when future work is pending?
- How best to resolve the question of whether the response of the Standard Drafting Team is complete?

Interpretation of CIP-006 for Progress Energy

- Approve the Interpretation of Requirement R1.1 of CIP-006—Cyber Security—Physical Security of Critical Cyber Assets (CIP-006) and direct staff to file with applicable regulatory authorities

Highlights

- Initial draft of the interpretation developed and posted for initial ballot in August 2008
  - Stakeholders did not support the draft interpretation
- Second draft interpretation developed and posted for initial ballot from September–October 2009
  - Stakeholders supported the draft interpretation
    - Project delayed based on reprioritization of the total standards workload
    - Project additionally delayed until the Standards Committee developed more formal processes for addressing interpretations in response to the Board of Trustees November 2009 guidance

Highlights

- April 2011–Standards Committee Interpretation Guidelines approved
- CIP Interpretation Drafting Team appointed in July 2011 to address the outstanding CIP interpretations in the order of the date of the request
  - Team determined the second draft interpretation did not conform to the NERC Guidelines for Interpretation
  - In light of the new guidance, a third interpretation was developed with consideration of all intervening commission orders

Ballot Results

- Third interpretation posted for comment on October 12, 2011, with a parallel successive ballot conducted from November 11–21, 2011
  - Quorum 84% , approval 96%
- Recirculation ballot conducted on December 9–19, 2011 and the interpretation was approved by stakeholders
  - Quorum 88% , approval 96%

Interpretation of COM-002-2 for the IRC

- Consider action on the Interpretation of Requirement R2 of COM-002-2—Communications and Coordination
- Interpretation handled in accordance with revised Standards Interpretation process
- In terms of Standards Process, Interpretation is here for approval by the board
- NERC management does not recommend approval at this time

History

- October 1, 2009–Clarification of Requirement R2 of COM-002-2 requested by the IRC
- Work on the interpretation initially delayed based on reprioritization of the total standards workload, and revision of the Standards Committee's process for addressing interpretations
- April 2011–Standards Committee Interpretation Guidelines approved
- Standards Committee initiated a plan to simultaneously address three part communication protocols through:
  - The interpretation of COM-002-2 as Project 2009-22
  - Project 2007-02 Operating Personnel Communications Protocols COM-003

Level 1 Appeal

- August 30, 2011–Standards Review Committee of the IRC submitted a Level 1 Appeal for inaction related to Project 2009-22
- Appeal of COM-002-2 Interpretation requested:
  - Project 2009-22 be given an “immediate/urgent” priority within 30 days of receiving the appeal
  - NERC to provide a formal explanation of the delays associated with the Project
  - In response to the appeal, the interpretation was moved forward separately from Project 2007-02

Ballot Results

- Revised interpretation posted for industry comment on October 10, 2011, with a parallel ballot conducted November 8-18, 2011
  - Quorum 91%, approval 95%
- Recirculation ballot conducted on December 14-23, 2011
  - Quorum 92% , approval 95%

Issues

- Reliability concerns
  - Interpretation, if enacted, will put Operators in the position of having to change communications approach during an emergency
  - Impact of miscommunication causing a mishap on the bulk power system does not differ whether it occurs during routine operations or during emergency operations
  - There have been events where review of the transcripts reveals miscommunication that contributed to the severity
- Compliance concerns
  - This also creates an unnecessary level of confusion for registered entities and compliance auditors

Revision of MOD-028-1 for FPL

- Approve the following standards documents and direct staff to file with applicable regulatory authorities:
  - Reliability Standard MOD-028-2–Area Interchange Methodology effective consistent with the Implementation Plan for MOD-028-2
  - Implementation Plan for MOD-028-2
- Rapid Revision Pilot

Highlights

- May 2011–Florida Power & Light (FPL) requested an interpretation of MOD-028-1, Requirement R3.1.
- Requirement R3 was modified to clarify language regarding load forecasting, to indicate:
  - For days two through 31, a daily load forecast is required (identical to the current standard)
  - For months two through 13, a monthly load forecast is required (identical to the current standard)
  - For current-day and next-day, entities may use either a daily or hourly load forecast
- The modifications do not change the scope or intent of the previously approved standard

Standards Process

- In the July 2011 the SC decided to use the Rapid Revision process for this interpretation request
- Ballot Process
  - The standard was posted for a parallel comment period and initial ballot on October 3, 2011, with the ballot conducted November 7-16, 2011
    - Quorum 88%, approval 86%
  - A recirculation ballot was conducted from December 12-22, 2011
    - Quorum 90%, approval 92%

Reliability Standard PRC-006-NPCC-1 – Automatic Underfrequency Load Shedding

- Approve PRC-006-NPCC-1 and supporting documents. Direct staff to file with applicable regulatory authorities
  - Reliability Standard PRC-006-NPCC-1–Automatic Underfrequency Load Shedding (UFLS)
  - Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for PRC-006-NPCC-1
  - Implementation Plan for PRC-006-NPCC-1

Background

- PRC-006-NPCC-1–automatic Underfrequency Load Shedding (NPCC UFLS Standard) was developed to provide regional requirements for Automatic Underfrequency Load Shedding (UFLS) to applicable entities in NPCC
  - The NPCC UFLS Standard applies to each Generator Owner, Planning Coordinator, Distribution Provider, and Transmission Owner in the NPCC Region

NPCC Standards Process

- Proposed UFLS standard posted for four stakeholder comment periods over a three-year period, with an initial ballot, a recirculation ballot, and approval by NPCC's Board of Directors
- Standard underwent two complete quality reviews by NERC staff
- UFLS standard posted on the NERC website for industry review to identify any process, interregional reliability, or market concerns

SERC Reliability Corporation Regional Standards Development Procedure

- Approve the following regional standards process and direct staff to file with applicable regulatory authorities:
  - Revision 2 of SERC Reliability Corporation Regional Standards Development Procedure dated December 14, 2011

Revisions

- Revision 1 of the SERC Regional Standards Development Procedure, Exhibit C to SERC Regional Delegation Agreement, approved by FERC and became effective January 3, 2009
- Revisions of this document were required to:
  - Address the document's three-year review and re-approval requirement
  - Address issues identified during the NERC 2009 audit of SERC
  - Make revisions to improve process efficiency and reduce time required to develop a regional standard
  - Ensure alignment with the NERC Standard Processes Manual
  - Ensure alignment with the revised SERC Bylaws
- Revision 2 approved by the SERC Board Executive Committee on December 14, 2011

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Event Analysis Process

NERC Board of Trustees Meeting
Earl Shockley, Director of Reliability Risk Management
February 9, 2012

RELIABILITY | ACCOUNTABILITY






Background

1. Working group scope approved by Operating Committee and Planning Committee (June 2010)
2. Team consisted of individuals representing NERC, Regional Entities, stakeholders
3. Field trial consisted of two phases of data gathering
4. Process document had two revision periods based on:
   - Input from many audiences
   - Surveys from stakeholders who participated in field trial
   - Lessons learned and opportunity of improvement from the field trial

Highlight

Collaborative effort by a diverse team of experts addressing a very sensitive subject

Next Steps

Seeking approval by the NERC Board of Trustees

- NERC staff comments
- Operating Committee (comments from Chair)
- Planning Committee (comments from Chair)

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Conclusion

- This is a success story
- There is a commitment to future learning

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Status of Critical Infrastructure Initiatives

Board of Trustees Meeting
Matt Blizard, Director of Critical Infrastructure Protection
February 9, 2012

RELIABILITY | ACCOUNTABILITY






Agenda

- White House Electric Sector Cybersecurity Risk Management Maturity Pilot Program
- Energy Security Public-Private Partnership (ES3P)
- Grid Exercise (GridEx) 2011
- Electricity Sector Information Sharing and Analysis Center (ES-ISAC)
- Improving critical infrastructure protection (CIP) Audits

White House Electric Sector Cybersecurity Risk Management Maturity Pilot Program

- White House initiative led by Department of Energy (DOE)
- Partnership with Department of Homeland Security (DHS)
- Key players - White House Staff, DOE, DHS, Electricity Sub-sector Coordinating Council, selected owner operators, and trade representatives
- Collaborative approach to develop
  - A cybersecurity risk management maturity model
  - A common understanding of cybersecurity risk management capabilities of the ES

White House Electric Sector Cybersecurity Risk Management Maturity Pilot Program

- Action Plan
  - Phase 1, complete maturity model
  - Phase 2, pilot the model and obtain feedback
  - Phase 3, finalize model and provide expanded use recommendation (April-May 2012)

Energy Security Public-Private Partnership (ES3P)

- Joint Working Group
- Brings DOE, DOD, and DHS together with industry and industry trade associations
- Provides a protected environment for Mission Assurance and Critical Infrastructure discussion
- Enhance resilience planning to achieve sustainable and cost-efficient CIP enhancements
- Formation documents complete; first meeting planned for the February-March timeframe

GridEx 2011

- Purpose
  - Validate readiness of the ES to respond to a cyber incident
  - Strengthen utilities' crisis response functions
  - Provide input for internal security program improvements
- Main Features
  - Crisis response, information sharing, and communications plans
- Key Findings
  - Enhance vertical information sharing
  - Clarify ES-ISAC/Situational Awareness roles internally
  - Entities possess effective cyber incident response plans, but updates to protocols and guidelines could enhance preparedness

ES-ISAC

- ES-ISAC Goals
  - Provide for sector-wide cyber and holistic security coordination, trust, and engagement
  - Registered Entities to securely find, share, and collaborate on critical infrastructure and security related information
  - Provide for the rapid analysis and sharing of information with the sector and its partners

ES-ISAC

- Enabling Tools in 2012
  - Extend the functionality and use of the secure members-only portal that was put in place in 2011
  - Portal will undergo aggressive schedule following several iterations of Design Build Test Promote cycles
  - Utilize Microsoft technology and maintain alignment with existing and future information technology (IT) in-house initiatives
  - Integration with DHS-operated National Cybersecurity and Communications Integration Center (NCCIC) watch
  - ESISAC Policy Statement

The portal will improve the vertical communications piece that was regarded as needed during GridEx 2011

ES-ISAC Portal

Current Status

- Current Pilot is in full swing for registered entities
  - Sent 150 invitations
  - Over 60 entities have registered (35% participation rate)
- Finalizing Charter and Project Plan now
  - Currently under review with IT
- Finalizing third-party contract
- Forming an advisory group from peer ISACs to provide guidance and lessons learned from their sectors on their portal development

CIP Oversight

- CIP Oversight Plans (2012)
  - Conduct 21 Oversight Audits in 2012 (up from 14 in 2011)
  - Conduct four CIP Auditor Workshops promoting consistency within the Electric Reliability Organization (ERO)
  - Host four CIP Standards and Compliance webinars to educate and update industry on CIP issues
  - Continue to work closely with the CIP Compliance Working Group to ensure Auditors are consistently applying good audit practices across ERO

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Legislative and External Affairs Update

NERC Board of Trustees Meeting
Janet Sena, Vice President and Director, Policy and External Affairs
February 9, 2012

RELIABILITY | ACCOUNTABILITY






2011 Reliability Topics

- February Cold Snap Event
  - New Mexico field hearing
  - FERC/NERC report
- September 8 Southwest Blackout
  - State legislative hearing
- October Northeast Snowstorm Event
  - Congressional letters

2011 Reliability Topics

- Long-Term Reliability Assessment Report
  - EPA MATS Rule Reliability Component
- FERC Technical Conferences
- FERC/NARUC Forum

2012 Congressional Activity

- Election Year Drivers
  - Economy
  - EPA Regulations
  - Taxes
  - Cybersecurity
- Cybersecurity Legislation
- Gridlock

Communications

- 212 media queries in 2011 – 20.5 monthly average
- Communications training for NERC management
- Regional Communicators Group

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Electricity Sub-sector Coordinating Council (ESCC) Update

Board of Trustees Meeting

February 9, 2012

RELIABILITY | ACCOUNTABILITY

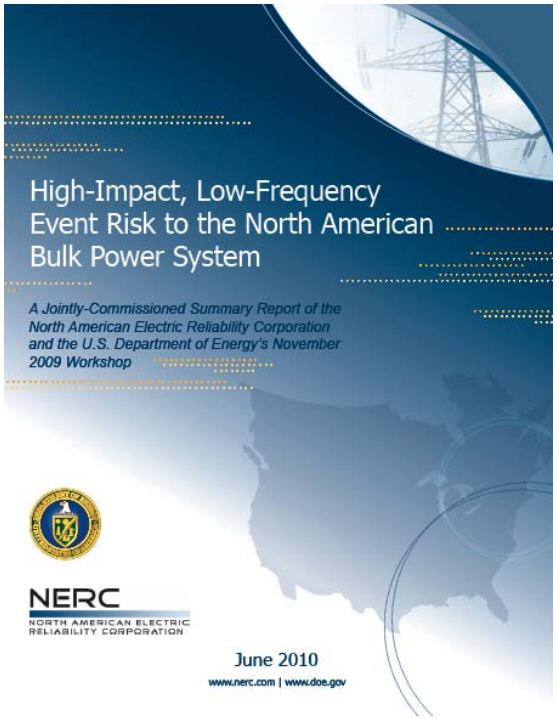


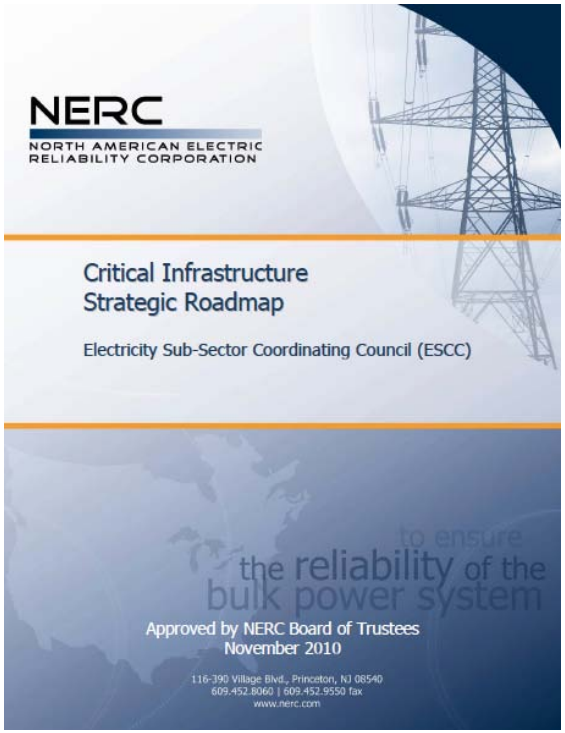



Electricity Critical Infrastructure NERC and Industry Actions

Strategic direction, coordinated action

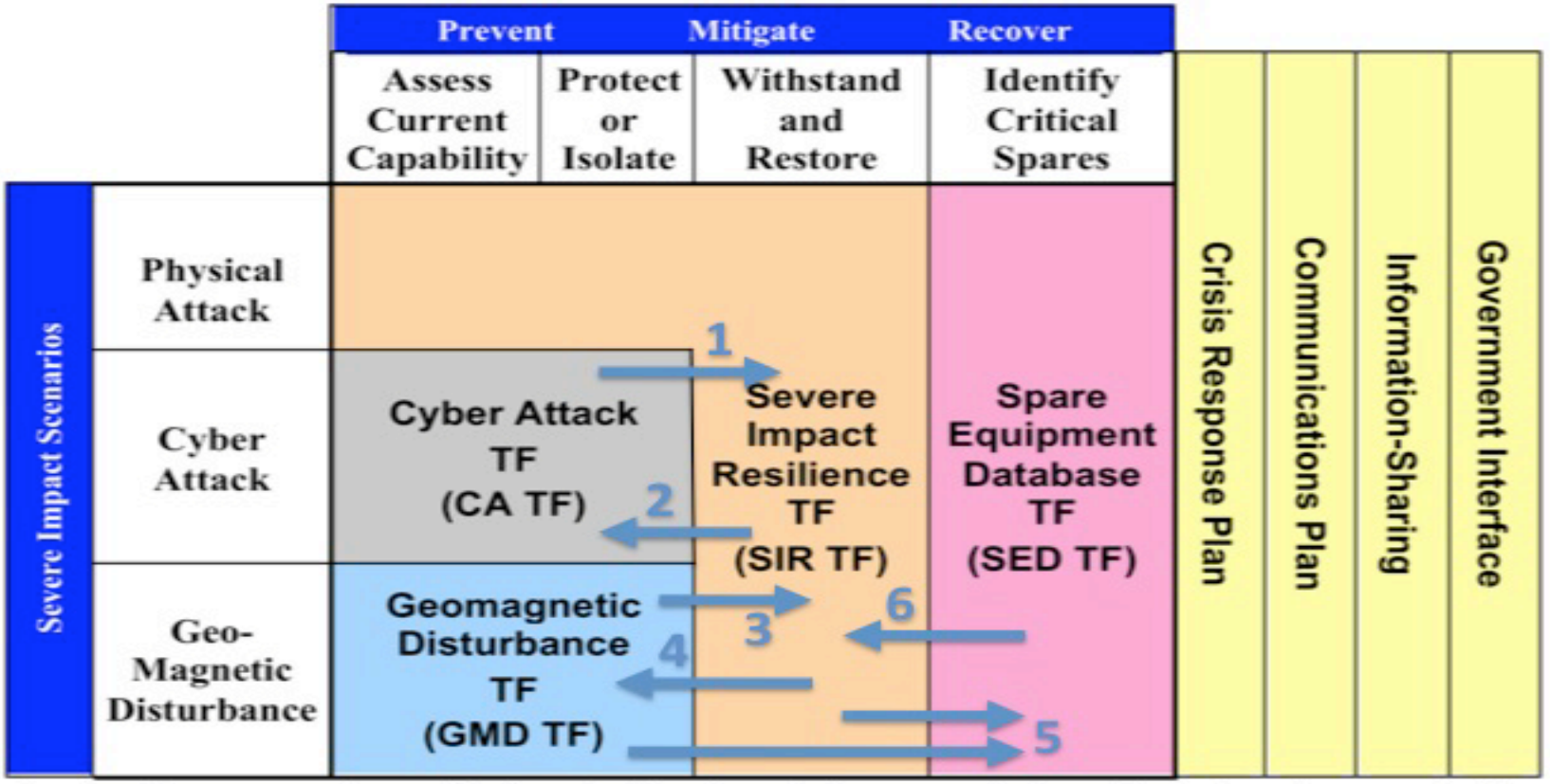
Vision → Goals → Risk Priorities → Scenario-based Approach → Coordinated Action Plan







Task Force Coordination



1 – Provide assessment regarding impact of a cyber attack on essential operator tools and communications.
2 – Identify essential operator tools and communications .
3 – Model the impact of GMD, identify system conditions that operators would face.
4 – Provide assessment regarding value of greater advance warning to operators.
5 – Provide assessments regarding number and type of critical equipment damaged.
6 – Identify critical equipment with limited supply and long delivery times.

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Task Force Opportunities

- Spare Equipment Database Task Force
  - Report complete, developing database
- Geomagnetic Disturbance Task Force (Feb 2012)
  - Further enhance understanding of transformer vulnerabilities
  - Further define “1-in-100 year” solar storm
  - Recommendations for industry action, but also additional study
- Cyber Attack Task Force (May 2012)
  - Limited industry input and comment, second request underway
- Severe Impact Resilience Task Force (estimate March 2012)
  - Stretch thinking beyond existing emergency capabilities
- All Task Forces
  - Communicate Task Force recommendations far and wide

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Task Force Completion Milestones

Task Force or Initiative	Report to be Approved by	Request Comments on Draft	Receive Comments on Draft	ESCC Review	Technical Committees Approve Final	MRC and Board of Trustees Review
Geomagnetic Disturbance	OC and PC	Dec 2, 2011	Jan 6, 2012	Feb 1, 2012	Feb 1, 2012	Feb 22, 2012
Spare Equipment Database	PC (with OC and CIPC endorsement)	Jun 1, 2011	Jun 29, 2011	Oct 3, 2011	Sep 13-15, 2011	Nov 2-3, 2011
Cyber Attack	CIPC (with OC endorsement)	Oct 15, 2011	Feb 8, 2012	Mid-Feb 2012	Mar 8, 2012	May 9, 2012 latest
Severe Impact Resilience	OC (with PC endorsement)	Dec 13-15, 2011	Jan 4, 2012	Feb 6, 2012	Feb 2012	Mar 2012 ?
NERC Crisis Plan	NERC CEO	-	-	Aug 16, 2011	Not Required	Not Required

Indicates complete

"?" Indicates to be confirmed

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NERC's Compliance Enforcement Initiative
Find, Fix, Track and Report Implementation

Compliance Committee Meeting – Open
Ken Lotterhos, Associate General Counsel and Director of Enforcement
February 8, 2012

RELIABILITY | ACCOUNTABILITY






Agenda

- Overview
- Data and Trends
- Guidelines
- Benefits
- Implementation Challenges
- Misconceptions
- Potential Improvements
- Six-month Filing with FERC
- Training Schedule

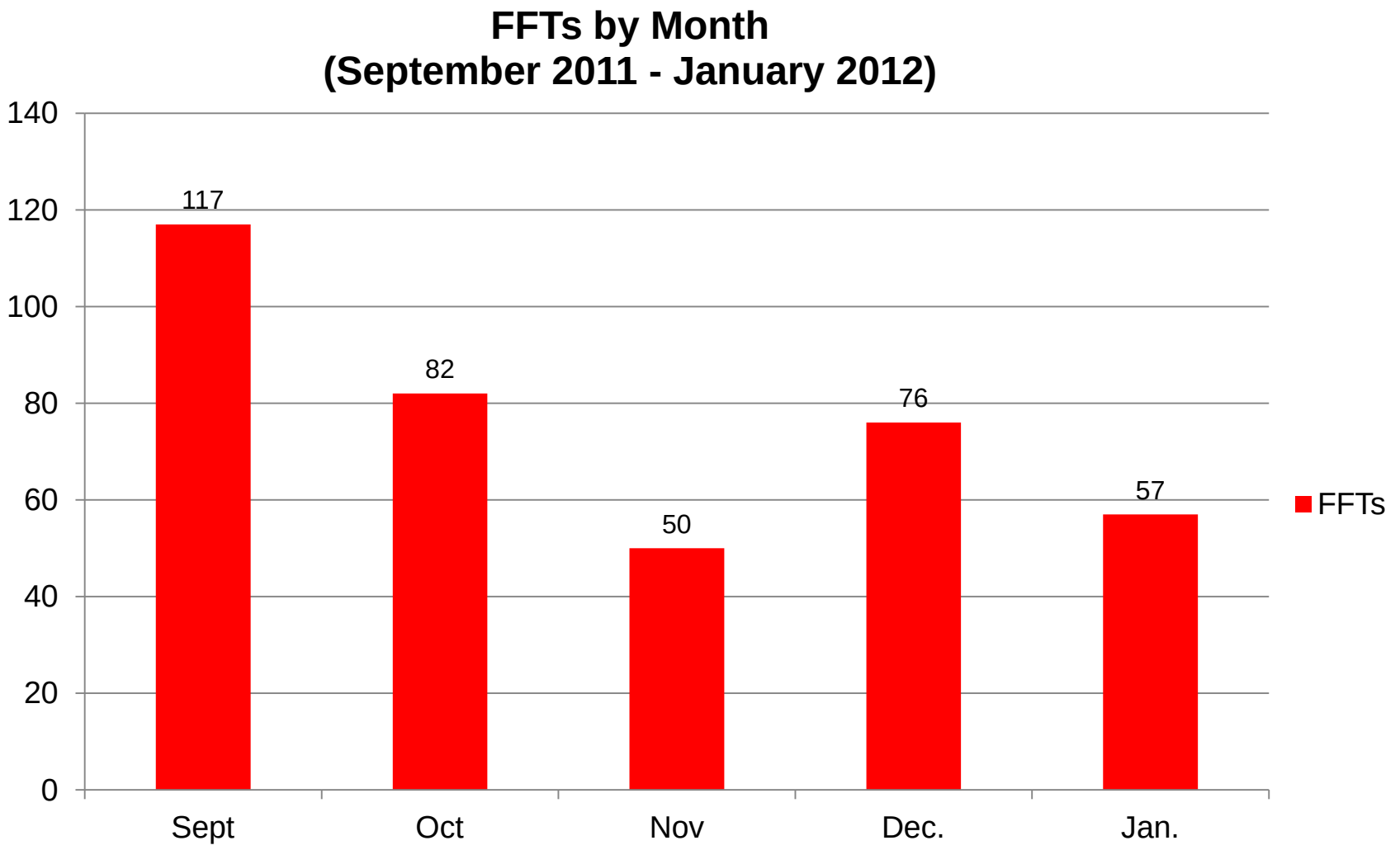
CEI Overview

- Four filings submitted to FERC from September to December, 2011
- Six month and one year status reports due to FERC in 2012
- All eight Regional Entities using new formats
- NERC is continuing outreach efforts to ensure successful implementation

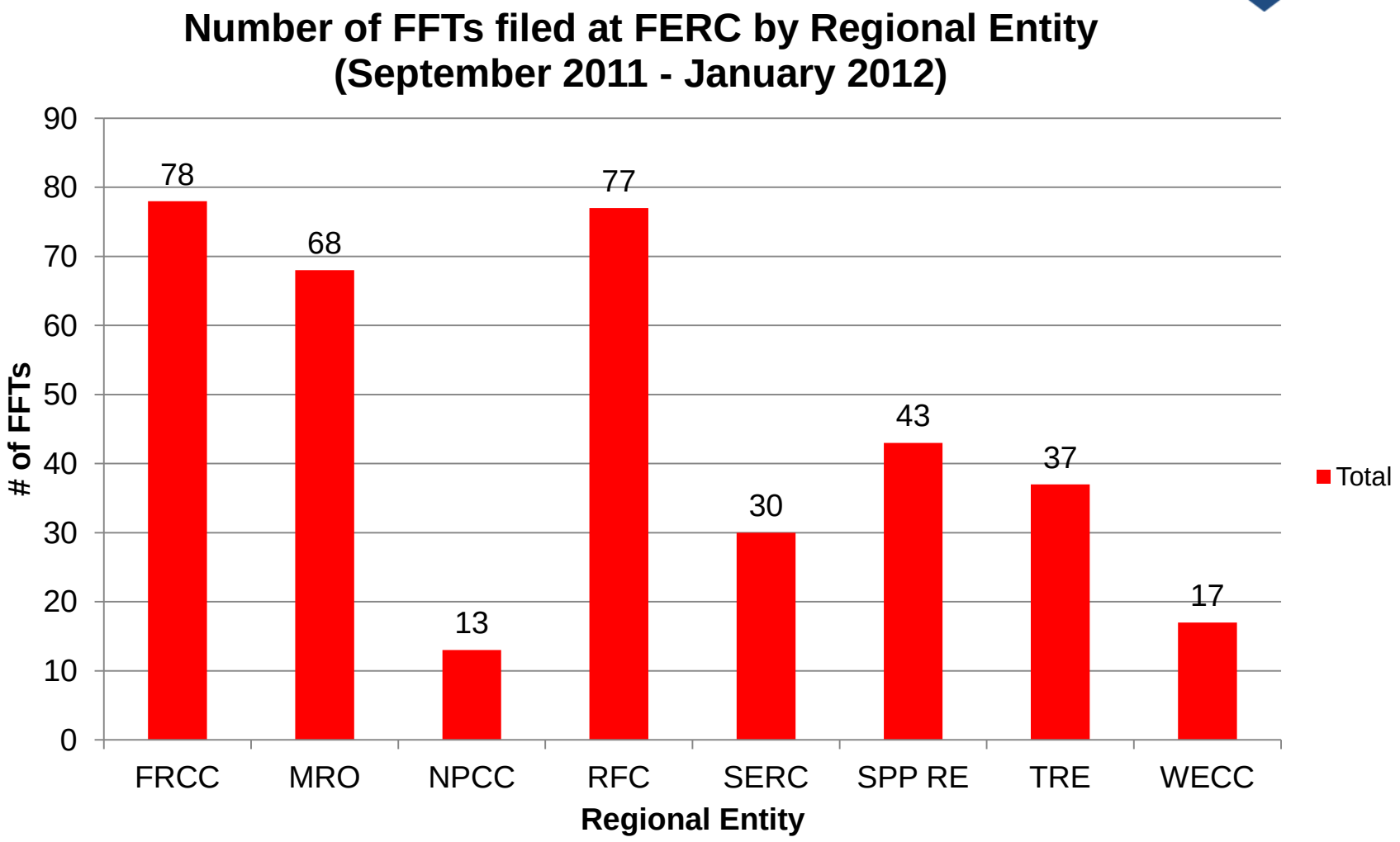
FFT Overview

- A Registered Entity may opt out of FFT processing
- Upon correction and submittal of FFT filing, the Possible Violation becomes a Remediated Issue
  - No penalty or sanction is assigned
  - Formal Mitigation Plans will not be required
  - Mitigating activity completion may be verified anytime
- Remediated Issues become part of a Registered Entity's compliance history
  - Remediated Issues may not be contested in subsequent enforcement actions

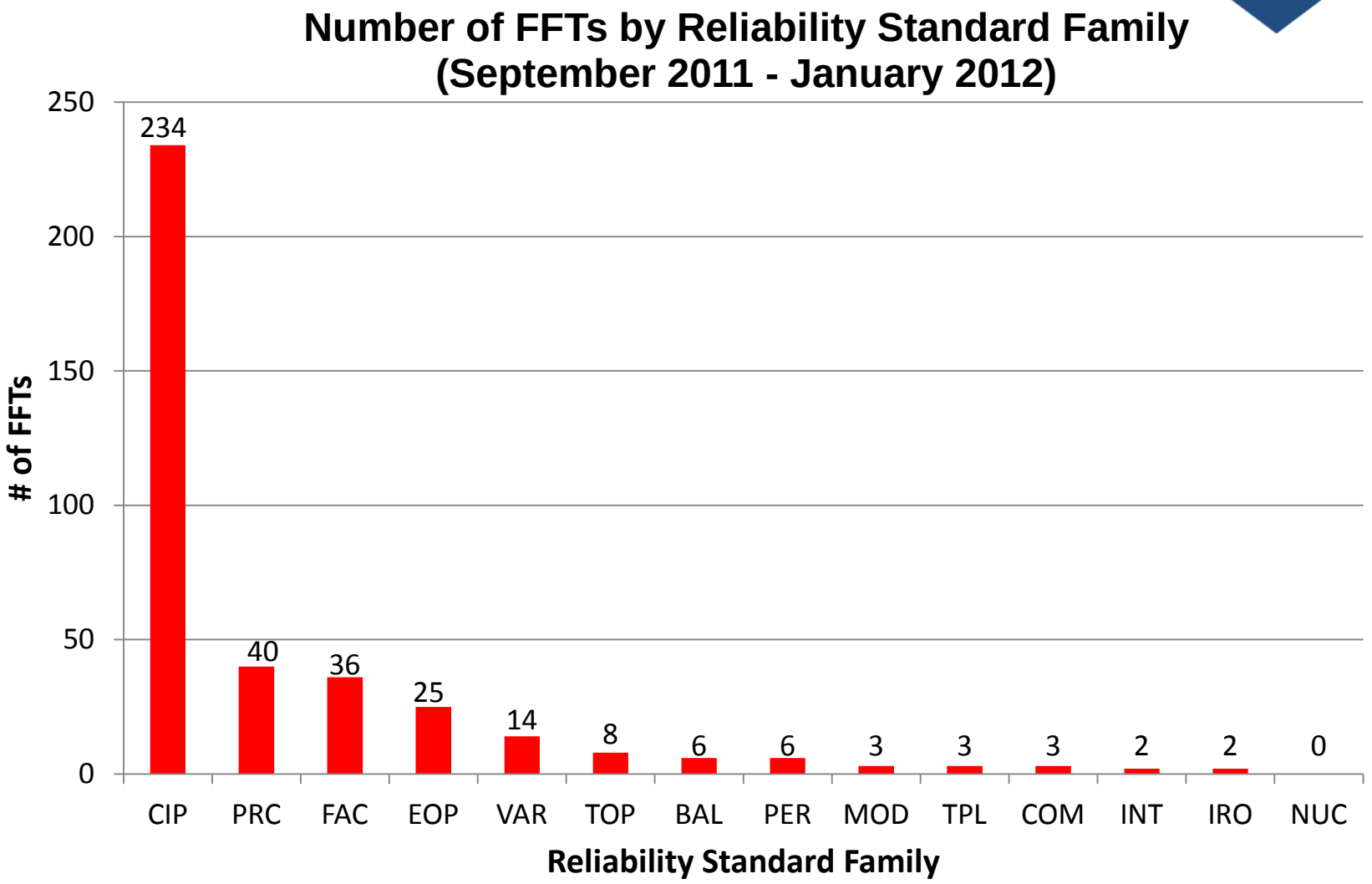
Data and Trends



Data and Trends



Data and Trends



Data and Trends

FFT Standard Breakdown (September 2011 - January 2012)

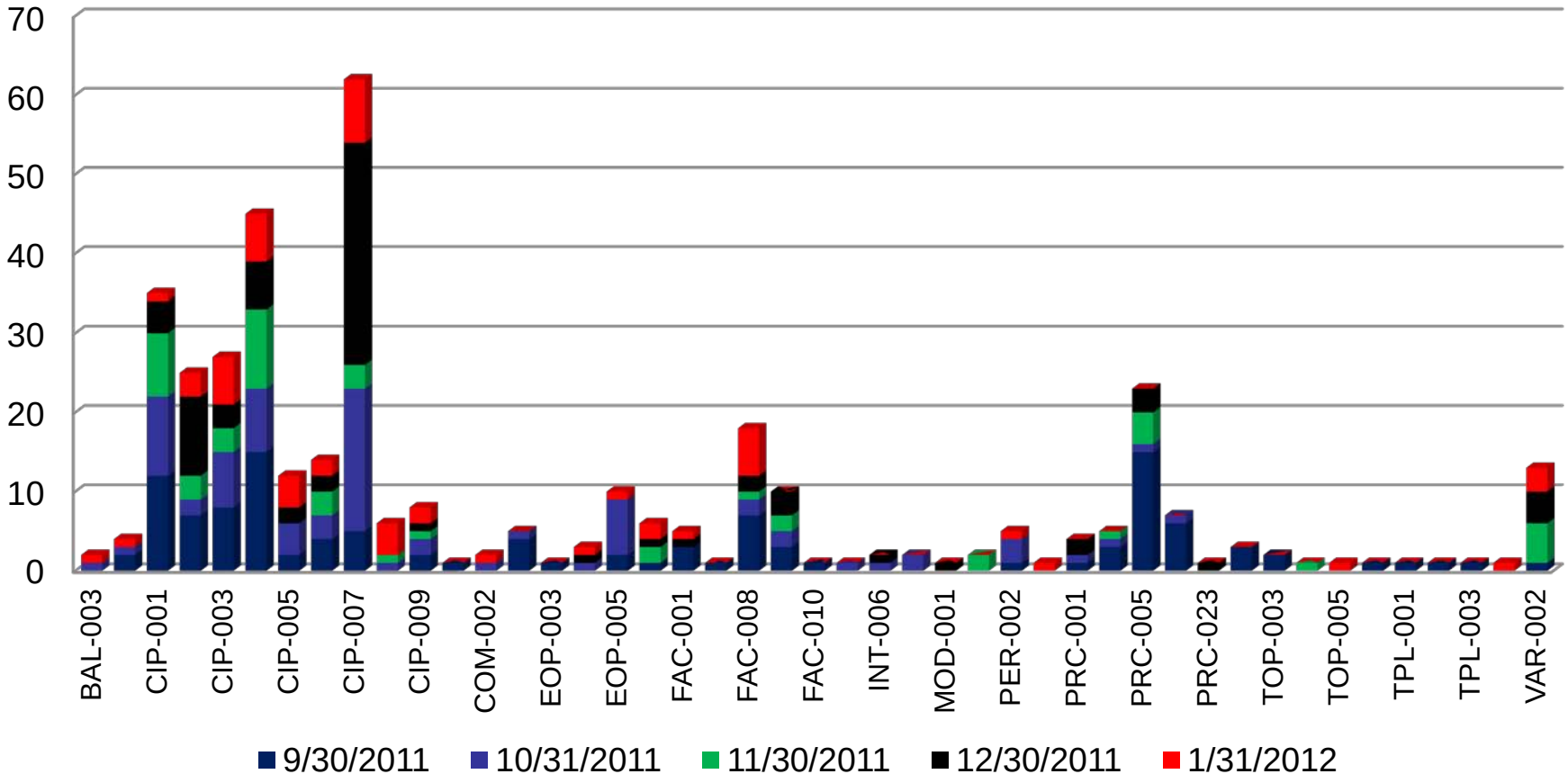
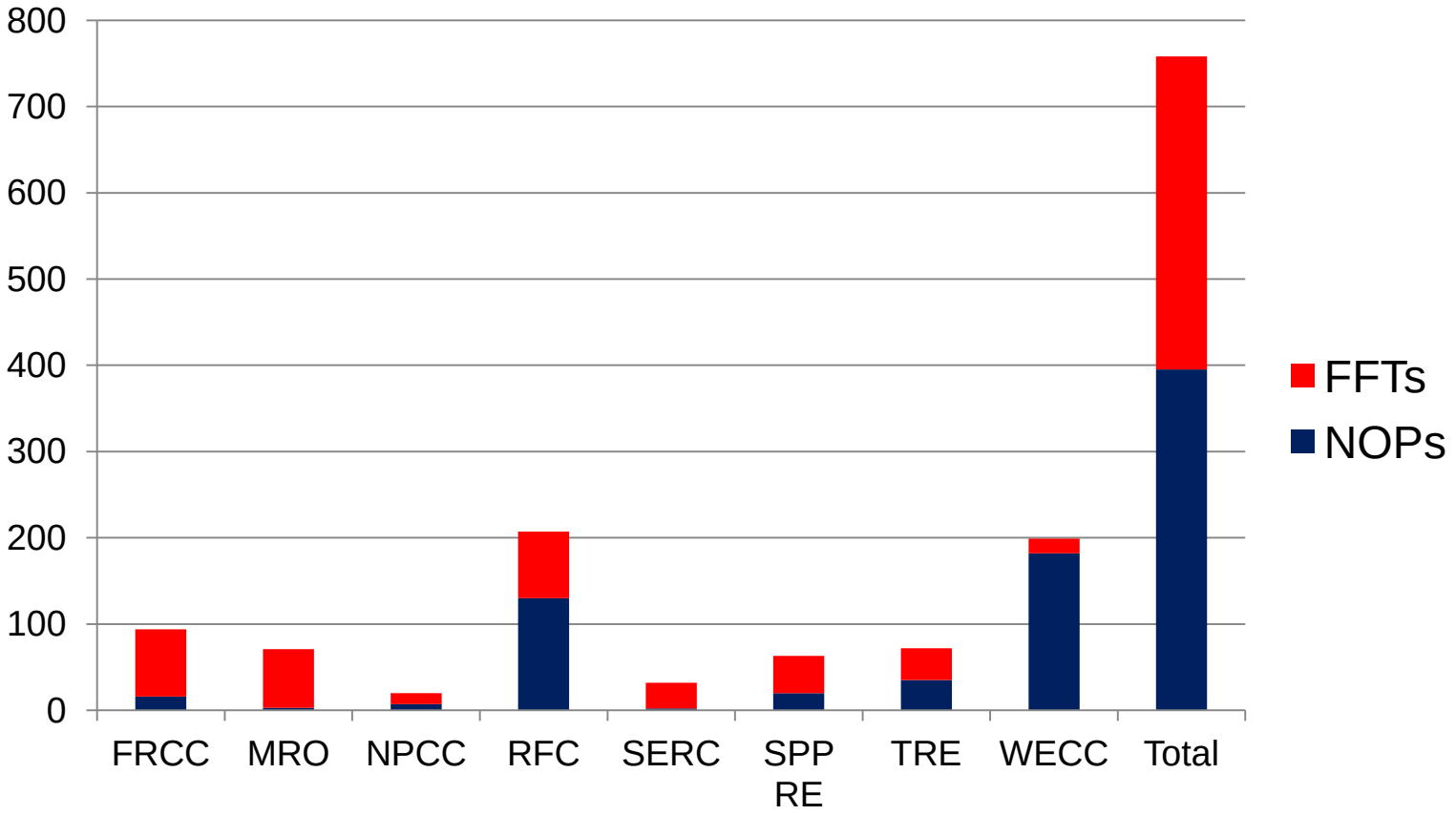


**Chart includes all version of the Standard*

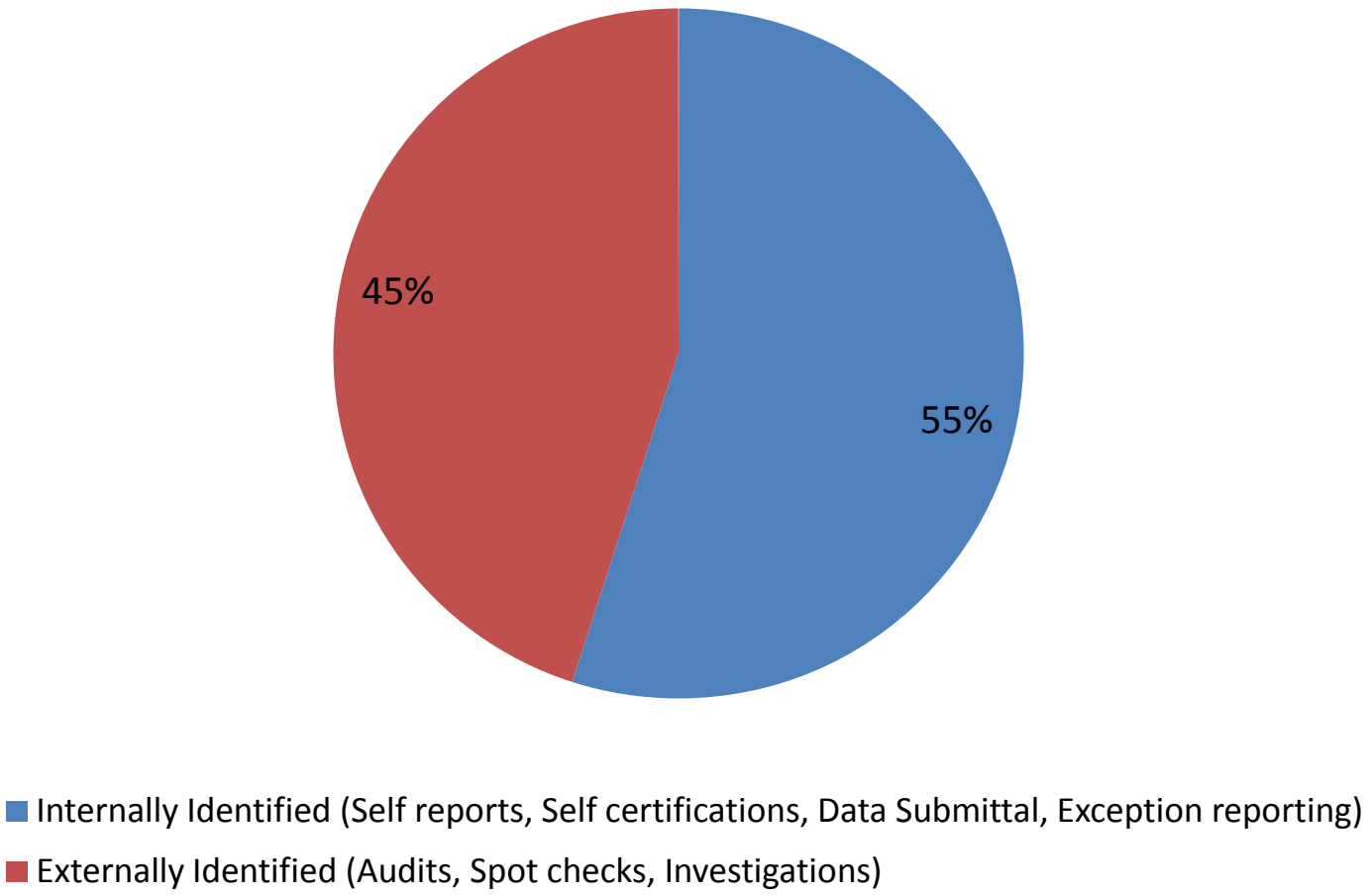
Data and Trends

Total FFTS/NOPs by Region (September 2011- January 2012)



Data and Trends

FFTs by Discovery Method as of January 31, 2012



Evaluation Guidance

- Lesser risk (minimal to moderate) to the reliability of the bulk power system (BPS)
- Does not include more serious risk issues
- Existing caseload and new possible violations eligible
- Mitigation completed
- Repeat violations eligible for consideration depending on circumstances

Representative FFTs

CIP-001 (Documentation)

Issue: Emergency Response Plan did not explicitly provide for sabotage response guidelines.

Risk (minimal)**:** Informal procedures existed and entity does not own any bulk electric system elements.

Mitigation: Updated current procedure and retrained all personnel.

Additional examples provided in the Appendix to this presentation.

Representative FFTs

PRC-008 (Documentation)

Issue: Of its 21 UFLS devices, no evidence of maintenance and testing for two station batteries.

Risk: Has past maintenance and testing dates and most recent UFLS testing records, only has two interconnection points and will only shed 23 MW of UFLS load.

Mitigation: Maintenance and testing policy updated and all devices tested.

Additional examples provided in the Appendix to this presentation.

Representative FFTs

VAR-002 (Operational)

Issue: Operator mistakenly placed a voltage regulator into automatic VAR mode rather than automatic voltage control mode (unclear manufacturer control labeling).

Risk: (minimal): Corrected promptly, all voltage schedules met, not called upon to support transmission system voltage, small entity, connected to the 138 kV.

Mitigation: Display screen modified, retrained operators on requirements for automatic voltage regulation and operation of the generator control panel.

Additional examples provided in the Appendix to this presentation.

Representative FFTs

CIP-007 (Documentation)

Issue: Entity self-reported it did not have a patch management procedure in place and updates were not documented.

Risk (minimal)**:** Patches were performed informally using an application to identify vulnerabilities in third party applications.

Mitigation: Ticket tracking system put in place and documented; all devices and updates now tracked and documented.

Additional examples provided in the Appendix to this presentation.

Representative FFTs

PRC-001 (Operational)

Issue: Substation tech disabled primary and backup relaying on a 345 kV line in the adjacent panel when drilling without notifying its TOP.

Risk (moderate): Relaying was disabled four minutes prior to notifying the registered TOP but high-speed clearing of the fault still would have occurred.

Mitigation: Operating personnel were retrained on proper notification procedures.

Additional examples provided in the Appendix to this presentation.

Some FFT Attributes

- Self-reported
- Lesser risk to bulk electric system elements
- Informal/automatic procedures existed
- Very few devices excluded
- Operated within good utility practice
- Short duration/promptly corrected
- Backup protection/process in place
- Trusted/experienced employee
- No event occurred during violation period

Potential Benefits

- Provides incentive to self-identify and fix issues more quickly
- Focus resources on more serious risks to reliability of the bulk power system
- Improve alignment of time, resources and record development with the risk posed to reliability
  - Expected for NERC, Regional Entities and registered entities

Potential Benefits

- Achieve efficiency gains
  - Backlog reduction is not a goal, but it is a benefit
- Reduce information dissemination delays
- Focus more time on ensuring reliable operations

Misconceptions Corrected

- FFT is not limited to older cases and documentation-only violations
- All possible violations of a given standard do not qualify for FFT
- There will be consistency in due process, even if outcomes are not identical

Implementation Challenges

- Ensuring consistency in evaluation and disposition
- Addressing pre-existing and repeat violations
- Determining risk posed to bulk power system reliability
- Considering registered entities' request for FFT treatment
- Developing IT solutions and revised self-report form

Transition Issues

- Uncertainty discourages some entities from participating
- Training compliance staff to make decision in the field will be a significant focus in 2012
- Phase II implementation is currently targeted in 2013

Potential Improvements

- In Phase II:
  - Continue to alleviate extensive record development burden for lesser risk violations
  - Provide guidance through FFT candidate examples
  - Enable compliance staff to identify FFTs
  - Reap benefits for all
- Beyond Phase II
  - Aggregated reporting of Remediated Issues

The 6 Month Report

- Report to be submitted on March 30, 2012
- Opportunities provided for input by Regional Entities and registered entities
  - SurveyMonkey
  - Member Representatives Committee meeting, February 8, 2012
  - Written comments before February 23, 2012
- Experience over first six months to be evaluated
  - Address guidelines, trends, benefits, implementation challenges transition issues, improvements, and training schedule

Registered Entity Survey

- Gathered information from the registered entity perspective on FFT implementation
- Preliminary survey results
- Will share the overall results of the survey

Training and Education

- Feb. 7-8: Audit Team Leader training class agenda item (quarterly)
- Feb. 21-23: CEA Staff workshop agenda item
- April: Half-day webinar for CEA staff
- Third Quarter: Begin online course for CEA staff
- Sept.: CEA staff workshop agenda item
- October: One year feedback information webinar
- Fourth Quarter: All CEA staff complete required training and training course updated dependent on Phase II changes

Conclusion

- NERC is continuing to work with Regional Entities and to engage in outreach efforts to ensure successful implementation
- Upcoming training activities will focus on specific case studies

Appendix – FFT Examples

FFT Examples

Standard	Description	Factors
CIP-001 R1, R2 and R3	Previous Emergency Response Plan did not explicitly provide for sabotage response guidelines but it did include emergency response guidelines and personnel to contact for reporting emergencies. Entity does not own any BES equipment, transmission lines, substations, UFLS, UVLS, or SPS equipment.	Informal procedures existed. Not BES.
PRC-008 R2	Of its 21 UFLS devices, the entity did not have evidence of maintenance and testing for 2 station batteries. Entity had the past maintenance and testing dates and the most recent UFLS relay maintenance and testing records but not maintenance and testing records of station batteries associated with its UFLS program. Entity only has two interconnection points and will only shed 23 MW of UFLS load, a failure of any part of its UFLS program will have a minimal impact to the BPS.	Entity had past and most recent records. Few devices missed. Lesser risk to BPS.
PRC-005-1 R1.1	Entity included maintenance and testing intervals for the devices in its Program, but it did not define the basis for those maintenance and testing intervals. Entity completed all maintenance and testing within the maintenance and testing intervals of its Program except for certain transmission relays, as noted in a separate enforcement action.	Lacked interval basis. Performed testing. Intervals adhered to Good Utility Practice

FFT Examples

Standard	Description	Factors
VAR-002 R1	Entity staff was informed they had to operate in automatic voltage control mode through internal communications and operating procedures, but an operator misunderstood the generator control panel and placed a voltage regulator into automatic VAR control mode instead of automatic voltage control mode. Another operator corrected this error the same day. The unit met all of the voltage schedules as provided by its Transmission Owner (TO) during the period of the issue, was not called upon by its TO in order to support transmission system voltage. It was small and connected to the 138 kV.	Self-reported Adequate procedures Corrected quickly Met schedules and not called upon Lesser risk to BPS
EOP-005 R7	Entity failed to demonstrate verification of its restoration procedure by actual testing or by simulation for a two year period but the entity had a documented restoration procedure in place that was used in tabletop training of its operators.	Had documentation Used tabletop training
CIP-007	Entity self reported it did not have a patch management procedure in place. Updates were not documented, but they were performed informally using an application to identify vulnerabilities in third party applications.	Self-reported Patch management performed by application.

FFT Examples

Standard	Description	Factors
PRC-001 R5	Contrary to an established procedure, a technician at a substation installing a disturbance monitoring panel disabled both primary and backup relaying on a 345 kV line in the adjacent panel to mitigate the risk of an operation due to the vibration of the drilling without notifying its Transmission Operator (TOP). Relaying was disabled four minutes prior to notifying the registered TOP. If a fault had occurred on the line, high-speed clearing of the fault still would have occurred.	Self-reported Procedure existed Short duration Backup protection
VAR-002 R2	Discovered during an audit, the entity operated outside the voltage schedule set by its TOP of 356 kV - 360 kV (358 kV +/- 2 kV) by up to -5 kV outside this schedule. Voltage regulators at the entity remained in automatic VAR mode, and the entity worked with its TOP to modify the schedule to provide a greater bandwidth where none of the deviations would have been outside the new bandwidth.	Automatic VAR Within corrected range
TOP-002 R14	Entity failed to notify the Balancing Authority/TOP (BA/TOP) of reduction in capabilities from 40 MW to 20 MW due to poor condition fuel. Deviation was minimal (out of 28,000 MW for the BA) and the duration for loss of capability was minimal, 11 hours in total for three occurrences on the same day.	Self-reported Minimal deviation Short duration

FFT Examples

Standard	Description	Factors
CIP-004	Through an internal compliance assessment, the entity discovered that although it documented and implemented its Personnel Risk Assessment (PRA) program. PRAs for current employees that were conducted prior to the effective date of the Standard were based on a five-year criminal background rather than a seven-year time interval. The entity also discovered that it was unable to locate PRAs for six individuals with unescorted physical access to CCAs and an additional one was discovered during a spot-check. The five-year interval covered a significant portion of the required seven-year time period for the current employees. Regarding the six individuals in which had no PRAs, all were long-term trusted employees with no disciplinary actions who had received the required cyber security training and after PRAs had been conducted, no PRA came back as having failed. With respect to the contractor who was inadvertently granted access to a newly identified restricted area without a PRA, the oversight corrected in less than two months, the contractor never attempted to enter the PSP, and even if he had his credentials would not have allowed him to open the secured door to the control center.	Self-reported Check covered most of period Trusted employees Backup precautions Corrected quickly
CIP-002-1 R3	Entity incorrectly identified ten network switches located within the entity's Electronic Security Perimeter as Protected Cyber Assets (PCAs), but they should have been identified as CCAs. Some of the entity's systems were essential to the reliable operation of the entity's control center. However, the PCAs and CCAs were afforded the same cyber security protection measures. Consequently, the misclassification of the network switches had no actual impact to the reliability of the BPS, and there was no increased risk to the reliability of the BPS.	Self-reported (portion of violations) Proper protection afforded

FFT Examples

Standard	Description	Factors
CIP-003	Entity's Cyber Security Policy did not include any provisions for emergency situations. This issue was corrected in a subsequent version of the policy a year later. Also, while the Cyber Security Policy was uploaded on the entity's intranet and made available, the entity's vendor did not receive a copy. Nevertheless, the vendor had received comprehensive training on CIP Standards and they fully understood the implications of their access to the entity's CCAs.	Training provided. Backup process
PRC-004	The entity found during self-certification that its procedures for analyzing and mitigating transmission Protection Systems Misoperations: (i) did not include sufficient detail; (ii) did not identify the responsible personnel assigned to perform each step in the process; and (iii) did not clearly define what constitutes a Misoperation. As a result, not all potential misoperations were being logged, monitored, and evaluated.	Self-reported Procedures existed Promptly corrected
EOP-001	The entity self-reported that it lacked sufficient evidence to demonstrate it had developed, maintained and implemented a set of plans for load shedding and system restoration. Even though the entity did not have a documented procedure, there is a load reduction schedule implemented in its SCADA system and system operators had been instructed in its use. The system operators have the authority to restore the system and to shed load as needed. Also, the entity is relatively small and has a radial connection only to a small municipal utility and the largest regional utility.	Self-reported Backup process Operators had proper instruction Lesser risk to BPS

FFT Examples

Standard	Description	Factors
EOP-005	The entity self-reported that one of seven system operators did not have a record of training for its System Restoration plan for a period of approximately two years. However, the operator was a twelve (12) year veteran dispatcher with the entity. No events upon which the training relied occurred during the time period, and the oversight was promptly noted. The employee received the training. Additionally, all other system operators had a record of training during this time.	Self-reported No events occurred during violation period Experienced operator No other occurrences

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Quarterly Statistics

Compliance Committee Meeting – Open
Ken Lotterhos, Associate General Counsel and Director of Enforcement
February 8, 2012

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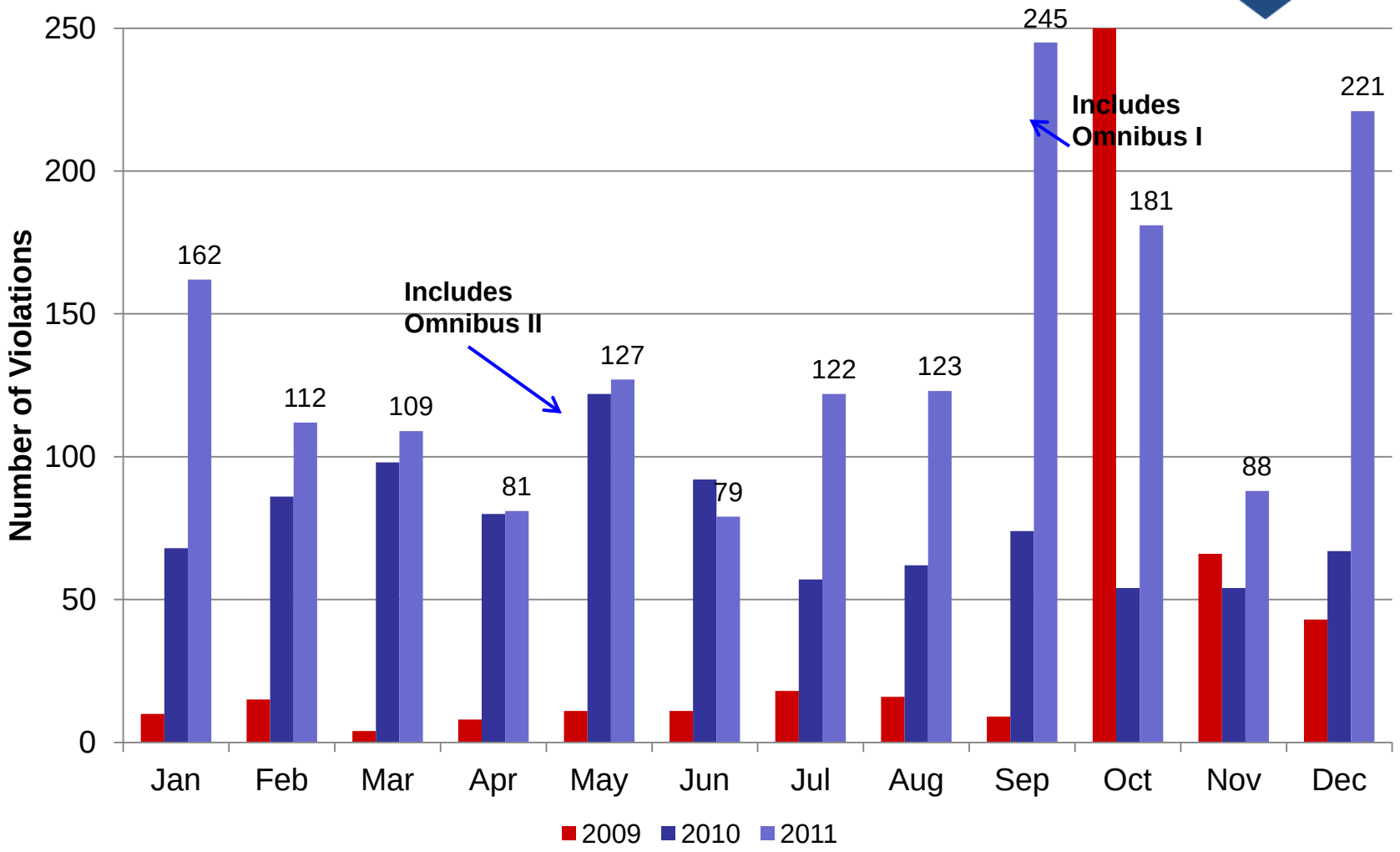





Overall Trends

- The number of new violations received in December was 242
- December 30 FERC filing
  - 76 FFT violations
  - 69 violations (54 via spreadsheet NOPs and 15 via full NOPs)
- Violation monthly receipt average
  - Last six months— 223 violations per month
  - Overall 2011— 248
  - Overall 2010— 168

Violations Approved by BOTCC



CEI Processing Statistics

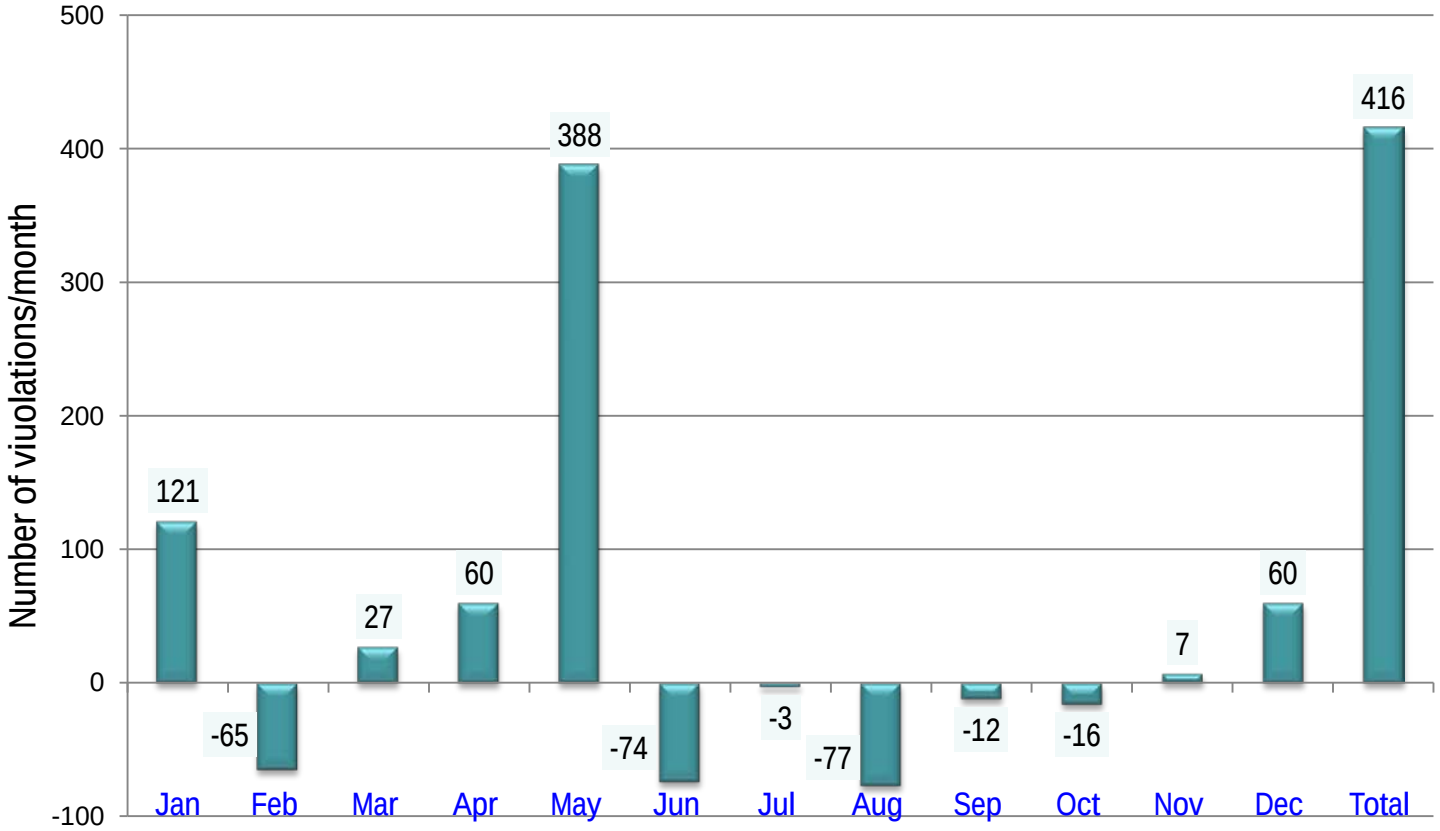
	Total Approved by the BOTCC		Total Filed with FERC
	NOP Violations	FFTs	
September	119	128	219
October	48	133	159
November	44	45	131
December	125	96	145

CEI Processing Statistics by Region

Total Approved by the BOTCC (NOP/FFT)

	September	October	November	December	January (submitted)
FRCC	12/30	0/25	0/2	0/16	0/5
MRO	0/24	1/9	0/11	1/26	1/5
NPCC	0/2	0/4	0/7	7/0	0/0
RFC	58/8	15/17	29/14	21/19	20/13
SERC	0/22	0/2	0/3	2/2	0/0
SPP RE	8/24	0/8	0/6	12/3	0/7
TRE	0/12	0/13	0/1	17/10	3/7
WECC	41/6	32/9	15/1	59/1	10/0

Violation Processing in 2011



New	218	212	190	219	581	223	211	166	262	247	212	242	2983
Dismissed and Filed	97	277	163	159	193	297	214	243	274	263	205	182	2567

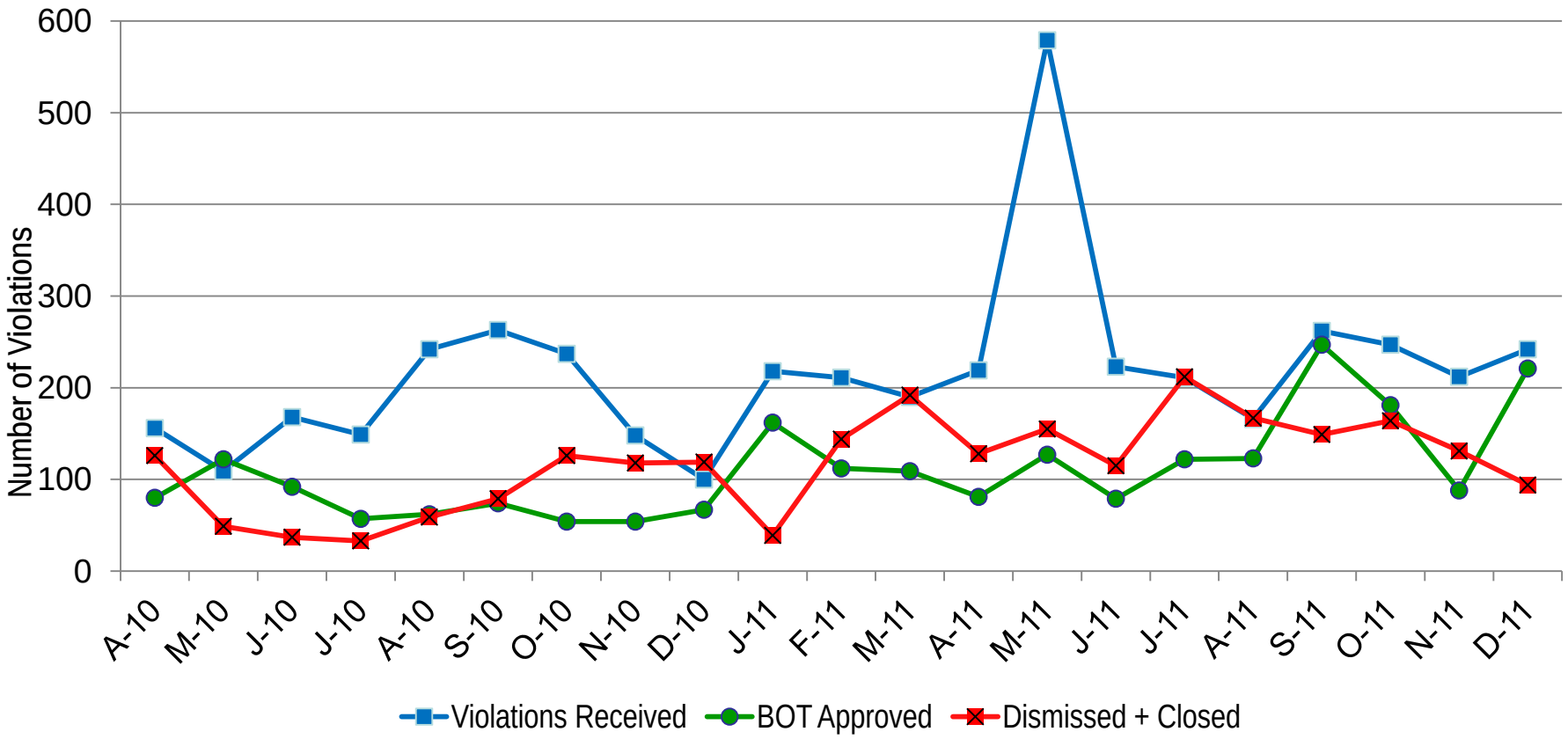
Caseload Index Description

- NERC Caseload Index
  - Total # of Active Violations divided by the 6-month average of # violations approved by the BOTCC (NOP, FFT and ACP)
- Variations
  - Common
    - 6-month average of # Dismissals added to process rate
  - Additional
    - Active violations reduced by ‘on-hold’ violations
    - Active violations reduced by violations accepted by FERC

Caseload Index for NERC

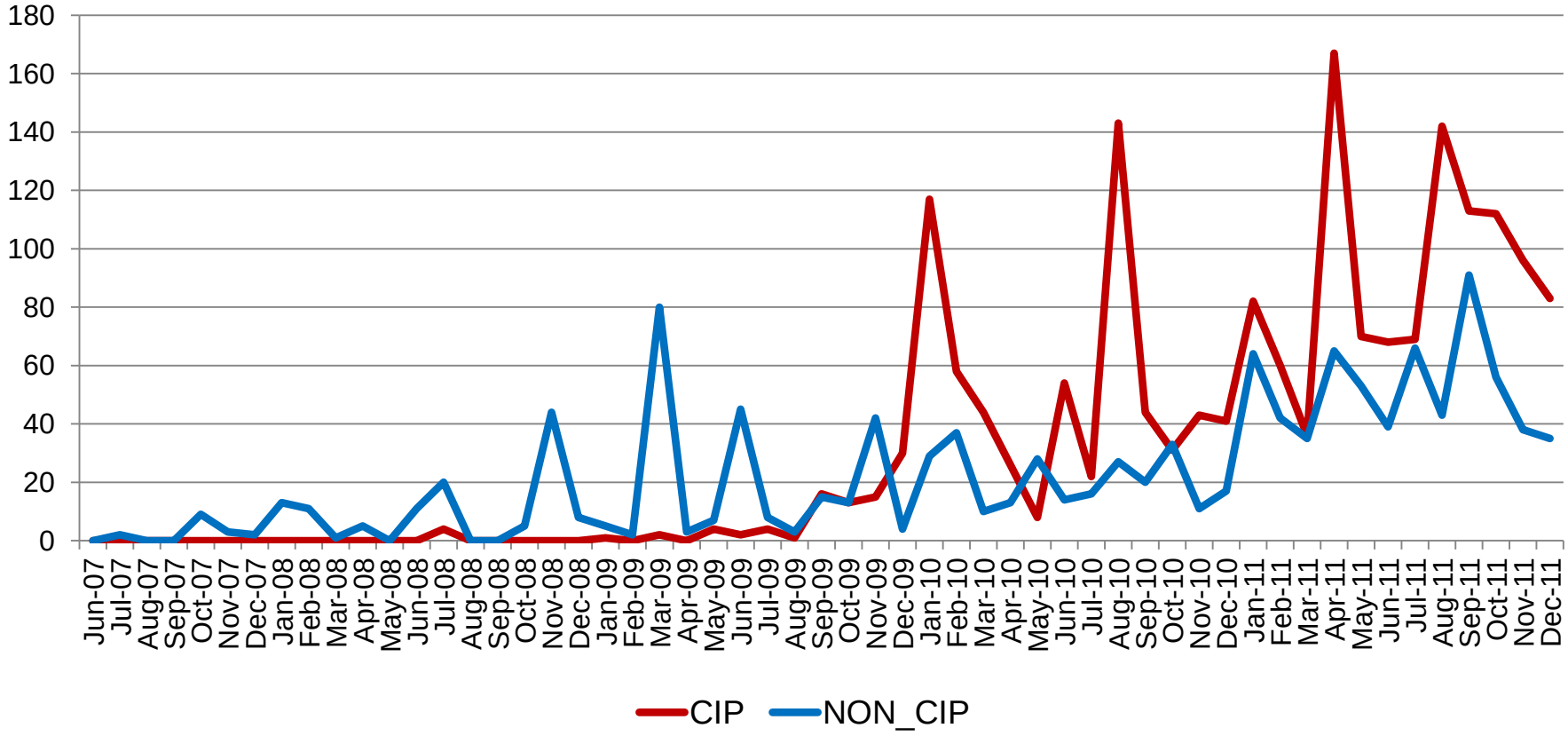
	Caseload Index –end of second quarter/end of third quarter/ end of fourth quarter (months)			
	Active	Active; Process Rate with Dismissals	Active less 'On Hold'; Process Rate with Dismissals	Active less Accepted by FERC; Process Rate with Dismissals
Total NERC	35/31/**24**	23/19/**16**	20/17/**14**	19/17/**13**

Violations In/Out Trend

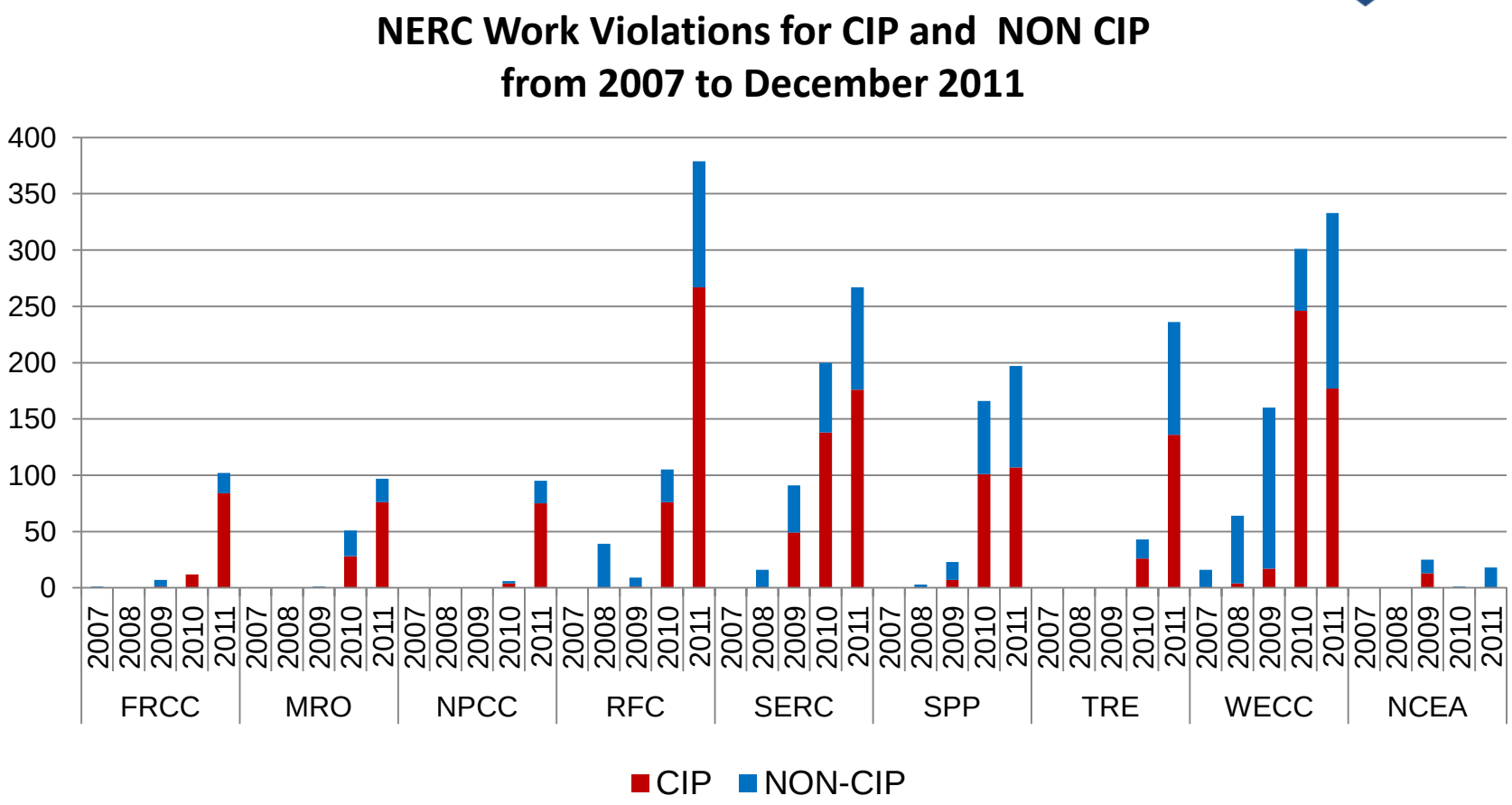


NERC Work CIP and Non-CIP Violations- Based on Discovery Dates from June 2007 to December 2011

NERC Work Violations, 3065 total
1821 CIP and 1244 Non CIP

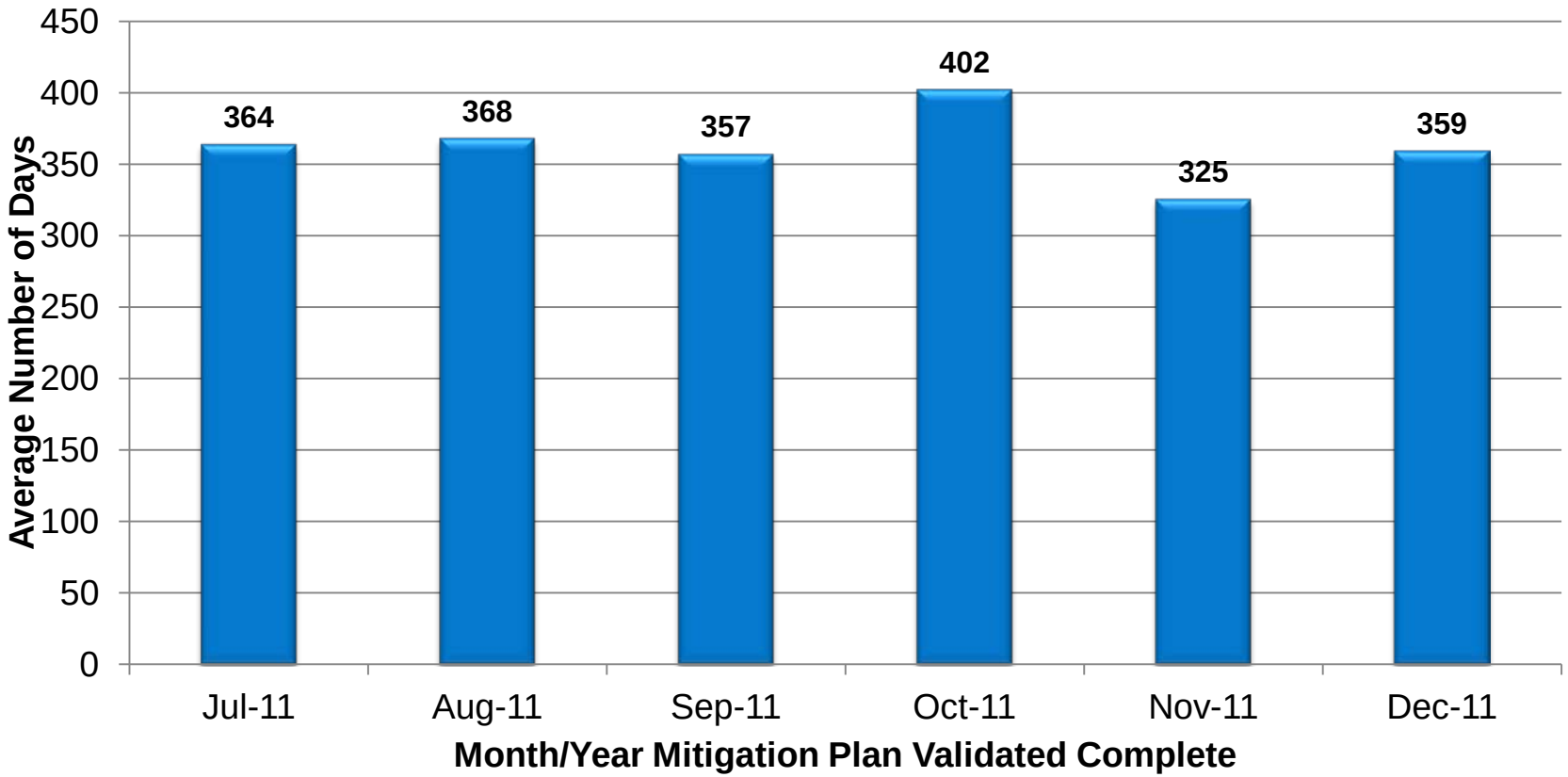


NERC Work CIP and Non-CIP Violations by Region

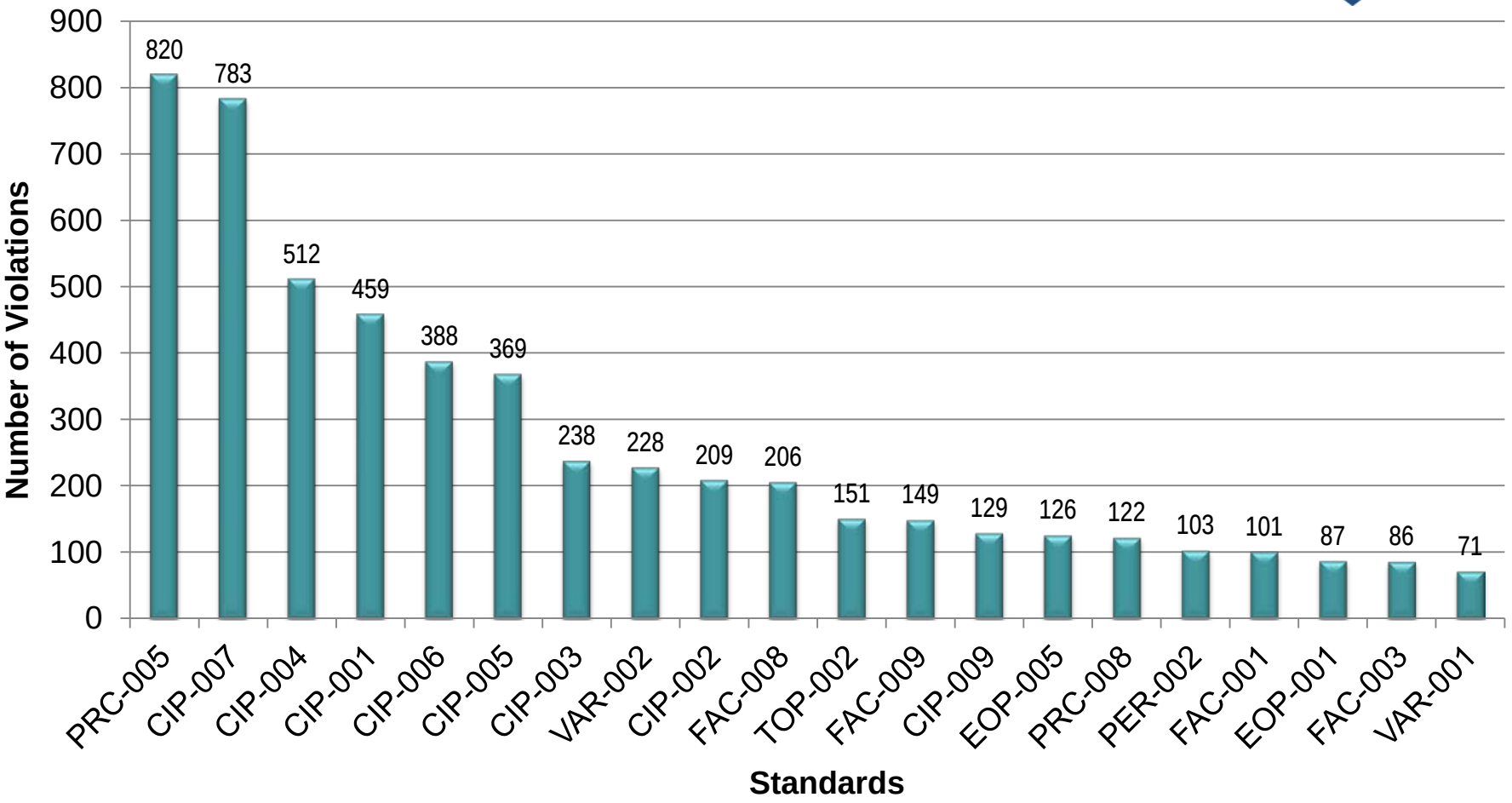


Rolling Six-Month MP Average Days from Discovery to Validate July 1 thru December 31, 2011

Total of 499 **violations** with a six-month average of 362 days to validate



Top 20 Enforceable Standards – Violated Active and Closed Violations thru 12/31/11



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Rules of Procedure Revisions

Member Representatives Committee Meeting
Rebecca Michael, Associate General Counsel, Corporate and Regulatory Matters
February 8, 2012

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Amendments to ROP

- Development History
- Postings in July and November 2011
- Amendments proposed
  - Sections 300, 400, 500, 600, 800, 1000 and 1400
  - Appendices 2, 4B, 4C, 5A and 5B
  - Deletion of Appendices 3C and 6

Response to Comments

- Highlights of key changes in response to comments
  - Elimination
    - Provision for NERC to assume jurisdiction over a hearing
    - Ability of the Hearing Body to increase a penalty due to frivolous filings, dilatory tactics, etc.
    - Provision for imposition of an administrative fine for failure to provide requested information
    - Risk-based assessment references
    - Public notification list for new Appendix 4C, Section 5.11
    - Modifications to Appendix 8, at this time

Highlights of Key Provisions

- Reliability Standards Provisions, Section 300 and Appendix 3C
- Personnel Certification, Appendix 6 deleted, materials moved to Section 600
- Sanction Guidelines, Appendix 4B
- Compliance Monitoring and Enforcement Program, Section 400 and Appendix 4C
- Organization Registration and Certification, Section 500 and Appendix 5A
- Reliability Tools, Section 1002

Next Steps

- Board of Trustees Agenda on February 9, 2012
- File with Applicable Governmental Authorities for approval thereafter

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Event Analysis Program Status

Member Representatives Committee Meeting
Earl Shockley, Director of Reliability Risk Management
February 8, 2012

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Problem Statement

Prior to the implementation of the event analysis (EA) field trial there was need for:

- A systematic, predictable and transparent event analysis process
- Review of bulk power system (BPS) events based on risk, significance and prioritization
- Consistent and timely reporting of event information
- Delivery and sharing of valuable lessons learned

Ultimately contributing to unnecessary risk to reliability of the BPS.

Effort Towards a Solution

Develop a program that addresses the Problem Statement

- Consolidate and form a new Event Analysis Working Group (EAWG) to develop a draft event analysis process document
- Develop guiding principles of the program
- Conduct an event analysis field trial to vet the draft process, solicit improvement opportunities, and industry feedback
- Finalize EA process document at conclusion of field trial

Key Benefits of Implementing

- Systematic, predictable and transparent process
- Prioritization methodology (5 Category levels)
- More structured and timely communication of event information
- Quality Lessons Learned program
- Systematic and aggressive critical self analysis by registered entities

Field Trial Responses

- **Brief Report** - provides concise explanation of "what happened". Submitted in Appendix A of the Events Analysis Process
- For Category 0 and 1 events NERC and regions review apparent and root causes, and then close to trend
- 100% reporting according to the event analysis process with quality information to understand what happened

Field Trial Responses

- **Event analysis reports -** Category 2 and above. Provides data and information to understand "How it happened", including causal factors
- 230 qualified events, 73 events were category 2 and above
- Received 88 event analysis reports
- **100% response** in delivery according to Event Analysis Process. Need to improve quality of reports

Field Trial Responses

- **Lessons Learned** - not every event on the BPS has a quality "Lesson" to share
- 230 qualifying events, received 119 lessons learned "candidates"
  - 55 of these came from the Cold Snap event of 2011
- Excluding the Cold Snap event, there were 64 other events which resulted in a lesson learned being submitted for consideration
- **Over 50 publications to date**

Field Trial Responses

- **Entity self assessment** - Category 2 and above. Provides information on the entities self assessment after an event
- 73 Category 2 and above events, NERC and Regional Entities received 112 assessments from entities.
  - 62 were from the Cold Snap event
- Excluding the Cold Snap event, NERC received an additional 50 submittals from other Category 2 and above events.

15 self-reports were submitted

Quality of Event Reports

- *75% of event analysis reports stop at the mode*
  - *<u>Failure Mode</u>:*
    The manner whereby the failure is observed
  - *<u>Failure Mechanism</u>:*
    Physical, chemical or other processes that led to the failure
  - *<u>Error Mode</u>:*
    The manner whereby the error is observed
  - *<u>Error Mechanism</u>:*
    Human actions along the skills, rules, knowledge continuum

Event Trending Case Study 1

- Trending analysis of bulk power system events identified approximately 15 occurrences where equipment was inadvertently left in an abnormal state following maintenance
- Extent of conditions was conducted by impacted entities, they discovered many more inadvertent abnormal configurations
- NERC Alert was issued “Reducing Human Performance Errors by the Use of Configuration Control Practices”

Event Trending Case Study 2

- Trending analysis of bulk power system events identified 27 Category 2b events (over the past 15 months) where a complete loss of SCADA/EMS lasted for more than 30 minutes.
- Current analysis of these events:
  - Software failure is a major contributing factor in 60% of the events.
  - Individual operator error has attributed less than 10% of the events

Event Trending Case Study 2

- Testing of the equipment has been shown to be a factor in over 50% of the failures:
  - Test environment did not match the production environment
  - Product design (Less than Adequate)
- Change Management had an impact in over 50% of the failures:
  - Risk and consequences associated with change not properly managed
  - Identified changes not implemented in a timely manner

NERC is currently drafting an industry alert

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Update on Registration and Applicable Standards - Generator Owners and Generator Operators that Own and Operate Transmission Facilities

Member Representatives Committee Meeting
February 8, 2012

RELIABILITY | ACCOUNTABILITY






History of Draft NERC Guidance

- In 2011, NERC proposed a draft registration guidance
  - Included an associated Memorandum of Understanding
  - Limited set of standards
  - Interim measure to close the reliability gap
  - Presented at the North American Generator Forum meeting/ webinar on October 18, 2011
  - Posted on NERC's website for industry comment November 11-18, 2011

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Registration Appeals

- NERC and FERC upheld registrations of:
  - New Harquahala
  - Cedar Creek
  - Milford Wind
- Three important outcomes:
  - Registration eliminates a reliability gap
  - Orders were limited and did not find that all GOs/GOPs should be registered as TO and/or TOPs
  - A limited set of applicable Reliability Standards may be appropriate based on facts and circumstances

Industry Response to Directive

- Respondents expressed concerns that it was not clear:
  - What the effect would be on registration, and
  - Whether a limited set of standards would apply
- General consensus was the:
  - Directive conflicted with efforts of Project 2010-07 SDT Generator Requirements at the Interconnection
  - NERC should direct Regional Entities to stop registering GOs/GOPs as TOs/TOPs

NERC Response to Comments

- In response to comments, work has ceased on the draft directive
- The ERO will continue to operate under current registry criteria and rules of the registration program

Next Steps

A decision to resume work on compliance guidance will be based on:

- Further input and perspective from industry and MRC
- The SDT's consideration for additional standards
- NERC Board of Trustees action on the proposed revision of FAC-001, FAC-003 and PRC-004 (Standards Project 2010-07)
- FERC approval of NERC compliance filing for Cedar Creek and Milford Wind



Discussion/Questions?

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Definition of Adequate Level of Reliability (ALR)

Member Representatives Committee Meeting
Allen Mosher, ALR Task Force Chair
February 8, 2012

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Background

- Adequate Level of Reliability Task Force (ALRTF) charged with:
  - Reviewing current definition of ALRTF (filed for information with FERC in 2008)
  - Determining if existing definition and characteristics need enhancement in coordination with the MRC's Bulk Electric system (BES)/ALR Policy Group
- Task Force includes representatives from each of the Standing Committees (Standards Committee, Compliance and Certification Committee, Operating Committee, Planning Committee, Critical Infrastructure Protection Committee

Background

- Goal
  - Develop definition that encompasses NERC's responsibility to ensure reliability
  - Define objectives and characteristics that are measurable
  - Enable the ERO enterprise to focus on and align its activities with specific characteristics of ALR that have the greatest impact on BES reliability
- Definition must be:
  - Concise, yet self-contained
  - Self-explanatory to BES planners and operators
  - Meaningful to policymakers; placing a premium on translation in the ALRTF Report

Background

- Input from MRC's BES/ALR Policy Group directed group to consider:
  - Cost/benefit
  - Load loss distinctions
  - Definition of cascading

Draft Definition Components

- Seven reliability objectives
- Associated expected performance outcomes
  - Addressed in four time frames
- Associated disturbances
  - Both predefined and beyond the scope of predefined disturbances

Reliability Objectives

1. The BES is free from instability, uncontrolled separation, cascading, and voltage collapse under normal operating conditions and when subject to predefined disturbances
2. BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances
3. BES voltage is maintained within defined parameters during normal operating conditions and when subject to predefined disturbances

Reliability Objectives

4. Sufficient transfer capability of the BES transmission system is provided and maintained to meet required BES demands during normal operating conditions and when subject to predefined disturbances
5. Sufficient resource capability on the BES is provided and maintained to meet required BES demands during normal operating conditions and when subject to predefined disturbances

Reliability Objectives

6. Adverse reliability impacts on the BES resulting from conditions beyond the scope of predefined disturbances (e.g., multiple contingences, unplanned and uncontrolled outages, cyber security events, malicious acts) are minimized
7. The system has the ability to recover from major system disturbances, such as blackouts and widespread outages, by restoring BES facilities in a controlled manner that rebuilds BES integrity and restores supply to load

Technical Document Outline

- Introduction
- Overview of ALR definition structure
- Performance outcomes
- Disturbances
- Means to meet reliability objectives
- Comparison with current ALR definition and NERC Reliability Principles

Associated Work

- White Paper on Social Impacts: Managing Risk and Socioeconomic Impacts of Reliable BES Operations
- Accompanying report focusing on process, policy considerations, metrics, implementation, and follow-on work

Schedule

- **January 31, 2012:** Draft definition—completed
- **February 10, 2012:** Technical document—to be completed
- **February 15, 2012:** ALRTF conference call
- **February 2012:** Present draft documents to SCCG for review
- **March 2012:** Discussion at standing committee meetings; post for industry comment
- **November 2012:** Final presentation to Board of Trustees for approval

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Reliability Standards

Definition of Bulk Electric System and Supporting Rules of Procedure

Member Representatives Committee Meeting
Herb Schrayshuen, NERC and Peter Heidrich, FRCC
February 8, 2012

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Definition of Bulk Electric System Phase 1

- Project update
  - Modifications made to the work product produced by the Rules of Procedure team prior to adoption by the Board of Trustees
  - The Board of Trustees approved the Definition and Rules of Procedure changes on January 18, 2012
  - The petition was filed with FERC on January 25, 2012

Thanks!!!!

Phase 2 Purpose

- Phase 2 of the project is being initiated to:
  - Develop appropriate technical justification to support refinements to the definition that were suggested by stakeholders during Phase 1
  - Refine the definition as technically justified

Standard Drafting Team (SDT) Activities

- Phase 1
  - Development of Guidance Document
- Phase 2
  - Finalize SAR
  - Develop Project Schedule
  - Development of “Technical Justification Project Plan”
  - Clarification issues identified in Phase 1

Near-term Project Milestones

- SDT Activities
  - January 2012–Initiated development of Guidance Document
  - February 2012–Process comments on initial Phase 2 SAR and develop project schedule
- SDT and NERC Technical Committee Leadership meetings
  - February 2012–Initiate development of Technical Justification Project Plan



Question & Answer

Website: http://www.nerc.com/filez/standards/Project2010-17_BES.html

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GMDTF Interim Report

Member Representatives Committee Meeting
Mark Lauby, Vice President and Director, Reliability Assessments and Performance Analysis
February 8, 2012

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Draft Conclusions

Preliminary Results – Not for Citation

Major Conclusion	• Highest likelihood is loss of reactive power, not large number of damaged transformers
Major Conclusion	• System operators will be challenged to maintain supply of reactive power for reliability
Major Conclusion	• Some transformer types may be damaged or loss of remaining life

Draft Actions/Recommendations

Preliminary Results – Not for Citation

- Refine GMD wave front models for 1 in 100 year and worst case storm events
- Create source tools for modeling, simulation, and system operations to measure and respond
- Categorize system vulnerability through simulation
- Require NERC Certified System Operators training to include focus on GMD
- Review NERC Reliability Standards for enhancement

Draft Next Steps

- Deploy actions/recommendations
- Accelerate industry collaborative research effort
  - NERC and EPRI effort with industry
  - In partnership with US and Canadian Government Agencies (FERC, NASA, NOAA, DOE, USGS, and NRCan)
- Engage Interconnection Modeling Groups
  - Industry modeling expertise to categorize local impacts
  - Enhance interconnection-wide models to for GMD
- Launch Phase 2 in Q2 2012

Schedule

- The draft interim report approval schedule:
  - January 23, 2012 – Draft Released to OC, PC, CIPC, ESCC
  - February 6, 2012 – OC/PC Review and Approval
  - February 23, 2012 – NERC Board of Trustees Review and Approval

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Agenda Item 3
SOTC Meeting
February 8, 2012

Information Technology Update

Standards Oversight and Technology Committee Meeting
Marvin Santerfeit, Director of Information Technology and Services
February 8, 2012

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Agenda

NERC Technology Update

- Key Accomplishments
  - Princeton to Atlanta Data Center
  - Washington DC office
  - Public-facing website
- NERC Information Technology Architecture Study
  - Key findings
  - Recommendations
- ERO Project Management Office Update
  - Accomplishments to date
  - Next steps

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Technology Update

- Princeton to Atlanta Data Center move 95% complete
- Washington DC new office completed on December 16, 2011
- Help Desk single point of contact (SPOC) established and implemented
- Implemented new Intranet site using SharePoint
- NERC public-facing website assessment completed
- Established NERC Information Technology Advisory Group (ITAG)
- Completed assessment of purchasing process for Microsoft licenses

NERC IT Architecture (ITA) Study

- Deloitte & Touche completed an ITA study for NERC from November 11, 2011 through January 23, 2012
- Key findings:
  - NERC Information Technology infrastructure follow best practices for redundancy and stability
  - NERC application review suggested consolidation of applications and data
  - NERC Information Technology must work to align services with best practices
  - Several resource enhancements are required to build organizational structure aligned with ERO requirements
  - NERC and the ERO Regional organizations must work together to align strategic application needs in order to maximize effectiveness

Project Management Office Update

- PMO staffed with three (3) resources
- Compliance Reporting and Tracking System (CRATS) identified as priority #1 by ERO EMG
- Business requirements effort underway to document CRATS Enforcement process steps
  - Next Steps - In collaboration with the ITSG develop agreed upon:
    - Vendor criteria
    - ERO processes for data submission, security, policies and reporting
    - ERO processes for application acceptance testing, deployment and enhancement
    - Extranet site for ERO visibility to project status

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Transition the Interchange Distribution Calculator (IDC) to the Industry Consortium

Standards Oversight and Technology Committee Meeting
Martin Santerfeit, Director of Information Technology and Services
February 8, 2012

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Transition the IDC to Industry

- NERC, Eastern RC entities, and OATI working transition
- Costs associated with the IDC collected as part of the NERC assessments from the Load Serving Entities (LSEs) in the Eastern Interconnection
- Present prospective members of consortium are the users of the IDC—not all of the Eastern Interconnection RC organizations

NEXT Steps and Schedule

- Finalize and execute the consortium agreement (2Q2012)
- Establish Steering Committee and begin operations (3Q2012)
- File and obtain FERC approval of the billing arrangement (2012)
- Change reporting relationship of the IDC Working Group to the Steering Committee (4Q2012)
- Commencement of new IDC contract (May 2013)

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Reliability Standards

Standards Oversight and Technology Committee Meeting
Herb Schrayshuen, Vice President Standards and Training
February 8, 2012

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Policy Issues

- Request for discussion and possible policy guidance for the following projects:
  - Project 2010-07 Generator Requirements at the Transmission Interface
  - Project 2009-22 Interpretation of COM-002-2 for the ISO/RTO Council (IRC)

Generator Requirements at the Transmission Interface (GO/TO)

- GO/TO Ad Hoc Report
  - 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 definitions

Standards Drafting Team (SDT) Opinion

- Assigning TO/TOP such responsibilities to GOs and GOPs would:
  - Require significant training for tasks
  - Require substantially more data and modeling responsibilities
  - Detract from the entities' primary functions to operate in a reliable manner
- SDT approached the gap in reliability differently than the Ad Hoc Task Force
- SDT recommended changes to Standards:
  - FAC-001, FAC-003, PRC-004, and PRC-005 future work

Standards Drafting Team

- SDT concluded:
  - Certain requirements are covered by other standards
  - Certain requirements will be addressed by standards to be revised or made applicable in the future
  - Modifying certain standards is not in the scope of the SDT
  - Following changes sufficiently address issues in original scope:
    - Changes proposed for FAC-001 and PRC-004 are currently pending Board of Trustees approval
    - Future changes to FAC-003 and PRC-005 are planned
    - A Compliance Application Notice (CAN)for PRC-001-1

Consideration of Standards

Standard	Ad Hoc Report	FERC Orders	NERC Draft Directive	SDT Opinion
EOP-003	X			Covered by PRC-001
EOP-005			X	Scope Expansion
FAC-001			X	Made applicable to GO
FAC-003	X	X	X	Made applicable to GO
FAC-014		X	X	Covered by FAC-008
IRO-005	X			Covered by PRC-001
PER-001	X			Covered by TOP-001
PER-002	X		X	Future Project
PER-003		X		Scope Expansion

Consideration of Standards

Standard	Ad Hoc Report	FERC Orders	NERC Draft Directive	SDT Opinion
PRC-001		X	X	Future CAN to address
PRC-004		X	X	Clarified gen. interconnection Facility inclusion
PRC-005		X	X	Clarified gen. interconnection Facility inclusion
TOP-001	X	X	X	Covered by TOP-002/TOP-003
TOP-004	X	X	X	Covered by TOP-001/TOP-002
TOP-006		X	X	Covered by PRC-001/FAC-001
TOP-008	X			Covered by TOP-001

Policy Questions

- Should NERC staff hold off filing when future work, that would complete the regulatory package more fully, is pending?
- How best to resolve the question of whether the response of the SDT is complete?

Interpretation of COM-002-2 for IRC

- October 1, 2009, clarification requested of Requirement R2 of COM-002-2 by the IRC
- Work on the interpretation initially delayed based on reprioritization of the total standards workload, and revision by the Standards Committee's process for addressing interpretations
- April 2011, the Standards Committee Interpretation Guidelines were approved
- Standards Committee initiated a plan to simultaneously address three part communication protocols through:
  - The interpretation of COM-002-2 as Project 2009-22
  - Project 2007-02 Operating Personnel Communications Protocols COM-003

Issues

- August 31, 2011-Standards Review Committee of the IRC submitted a Level 1 Appeal for Inaction related to Project 2009-22
  - Appeal of COM-002-2 Interpretation requested:
    - Project 2009-22 be given an “immediate/urgent” priority within 30 days of receiving the appeal
    - NERC to provide a formal explanation of the delays associated with the Project
    - In response to the time-frame required for an Appeal, the interpretation was moved forward separately from Project 2007-02

Issues

- Reliability concerns:
  - Interpretation, if enacted, will put Operators in the position of having to change communications approach during an emergency
  - The impact of miscommunication causing a mishap on the bulk power system does not differ whether it occurs during routine operations or during emergency operations
  - There have been events where the severity has been increased due to miscommunication
- Compliance concerns:
  - Creates an unnecessary level of confusion for registered entities and compliance auditors

Operating Personnel Communications Protocols (COM-003)

- Purpose of COM-003:
  - Require that real-time system operators use standardized communication protocols during normal and emergency operations to improve situational awareness and shorten response time.
- Project Schedule:
  - Initial Ballot—Late April/Early May
  - Successive Ballot—Late August/Early September
  - Recirculation Ballot—Early November
  - Board of Trustees approval in November 2012/February 2013 is possible, if no successive ballot is needed

From:	Guy V. Zito
To:	rsg
Cc:	Ed Schwerdt; Philip A. Fedora
Subject:	Notes from the TIS/SPCS discussion regarding SPS Definition
Date:	Tuesday, December 13, 2011 4:33:16 PM

RSG Members,

As part of an ongoing action assignment to me to report on the development activities of the SPS definition, I am submitting an excerpt of notes from the joint TIS/SPCS meeting where this was discussed. I did not attend this particular meeting but a member of NPCC's staff was present and provided the below regarding the SPS definition development effort...

"Proposed draft Definition:
A scheme designed to detect predetermined system conditions and automatically take corrective actions other than and/or in addition to the isolation of faulted components, to maintain system reliability and acceptable BES performance according to the applicable NERC TPL Reliability Standard. (Not needed for TPL – not an SPS)

Team proposes classification into 4 types of SPS – planning vs. extreme events, local vs. wide area. The intent is to write requirements around them. (This approach is similar to NPCC Directory 7.)

Definition for Wide-Area Effect:
Scheme failure to operate could result in any of the following

- System voltage performance criteria violation as determined by PC

- Load loss >= 300 MW

- Gen loss (other than loss of single unit) > = 1000 MW

(More thought to go into this proposal.)
Exclusions:

1. UFLS, UVLS

2. Locally sensing protection and control schemes designed to protect against equipment damage by directly tripping the affected equipment

3. Autoreclosing schemes

4. Locally sensed and switched series and shunt reactive devices and tap-changing transformers that are applied in normal operation of the system

5. Out-of-step relaying that is not designed as an integral part of an SPS

6. Automated actions that could be performed by an operator in a reasonale amount of time, including alternate source schemes

7. Schemes that provide anti-islanding protection for generators

8. Schemes that are installed temporarily (less than 60 days) to facilitate matainance, construction projects, or system restoration and have no wide-area impact

9. Back up protection schemes that trip local breakers other than those on the faulted circuit such as bus sectionalizing/splitting/break-up schemes."

I will continue to follow this activity and keep you all informed. As we discussed previously, this has standards as well as compliance implications. Ultimately the draft definition will enter the standards

development process phase of its development and approval so a number of opportunities to comment will be available.

Happy Holidays,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
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212-840-1070
212-302-2782 fax

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You are curr

From: Rueckert, Steve
To: rsg
Subject: RE: NERC - RSG - Whitepaper discussion
Date: Friday, January 20, 2012 12:27:48 PM

I agree with Guy's descriptions of how a Regional Variance may be developed. As a region with Regional Variances in a few NERC CW standards, we have developed and had them included in the CW standard using both methods described by Guy.

Thank you,

Steven Rueckert
Director of Standards
Western Electricity Coordinating Council
155 North 400 West
Suite 200
Salt Lake City, Utah 84103-1114
Phone (801) 883-6878
Cell (801) 558-0301
www.wecc.biz

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-----Original Message-----
From: Guy V. Zito [mailto:gzito@npcc.org]
Sent: Friday, January 20, 2012 5:36 AM
To: rsg
Subject: RE: NERC - RSG - Whitepaper discussion

Don,

Maybe I can help being the "old timer" involved with this from the start, along with Pat on the RRSWG. I do agree with you that clarification is needed. Perhaps the paper can help in this regard. The below represents my understanding, as of this time, and is based on past discussions at the RRSWG and history. The below is not necessarily indicative of what should be changed to reflect past understanding or future paths and provided simply to add "context" to the discussions.

Regional Differences (RD) and Regional Standards (RS) can be developed differently. RS are developed using the regions' approved process while the RD are developed, if concurrently with the CWS, by the NERC SDT and pass through the NERC full process along with the rest of the standard. If the RD is developed later on, after a CWS is developed, then the process by which the RD would be developed is up to the Region, then later, depending on whether it is interconnection wide or not, would enter the whole NERC process.

A RS either augments(more stringent, more specific, or facilitates) a CWS, or addresses something for which there is no CWS. The RS is generally more specific, and if the requirement(s) are more stringent then the CWS the auditors will audit will replace the corresponding CWS requirements with the RS requirements and audit only to the more stringent requirment(s).

A RD is something that achieves the reliablity objective of the CWS's requirement(s) in an "different" or

alternate way then described. For example- any requirement in a CWS that specified "adjacent BA" is not possible in Texas so an "alternate" way of accomplishing the reliablity object of that requirement could result in a RD. Also, in most cases for those regions arranged on an non-interconnection wide basis, the RD may be very difficult to develop and approve. It may be very hard to justify why on region in the EI needs it and others do not. In these instances RS would be the better approach towards addressing reliablity gaps or concerns.

Hope this helps. The RSG should discuss this further so we are all in agreement. Then we should adjust the whitepaper and make recommendations to revise existing documents accordingly to reflect what is efficient and effective and also to provide consistent guidance and promote understanding.

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: Jones, Donald [Don.Jones@texasre.org]
Sent: Wednesday, January 18, 2012 11:20 AM
To: rsg
Cc: 'rsg (rsg@listserv.nerc.com)'
Subject: RE: NERC - RSG - Whitepaper discussion

Thanks Howard.
I said I would provide some input on this issue for your consideration, and here it is:

Note:
This may not be entirely consistent with existing descriptions of "Regional Standard" and "Regional Variance" in other documents - those other documents may have to be changed to make everything consistent. I think one reason for the confusion that started this project is that various existing documents are inconsistent with each other and they need to be aligned.

Here is my input:

First, I question whether we really need to make a distinction between "Regional Standards" and "Regional Variances." Is there a process difference, or a difference in the way the requirements are applied? I don't think so.

In my mind, the difference should be simply defined:

. A "Regional Standard" contains new requirements that are in addition to CW requirements. It does not remove or modify any requirements in any existing standards. This would include making existing requirements applicable to additional functions or entities or facilities.

. A "Regional Variance" removes or modifies CW requirements in a region, replacing CW requirements with region-specific requirements. A Variance may include new requirements.

I think these two categories cover the universe of options.* The difference depends solely on whether you are removing or modifying any existing requirements as applied to any entities. I can see that a Variance might get more scrutiny because it could reduce the performance required under existing standards.

Our CIP-001-TRE Regional Variance would have been a "Regional Standard" under this paradigm, but it really doesn't make any difference - the resulting requirements are the same either way.

*One other circumstance to consider is where a NERC SDT includes Region-specific or Interconnection-specific requirements or criteria in a CW standard (which we would like to see more of). I think of that

as a "Regional Difference," to distinguish it from requirements that come of out of a Regional process.

Hope that is helpful. I look forward to continued discussion on this topic.

Don Jones
Reliability Standards Manager
Texas Reliability Entity, Inc.
o: 512-583-4929 | m: 512-627-3750
805 Las Cimas Parkway, Suite 200
Austin, Texas 78746
don.jones@texasre.org<mailto:don.jones@texasre.org>

From: Howard Gugel [mailto:Howard.Gugel@nerc.net]
Sent: Wednesday, January 18, 2012 9:28 AM
To: rsg_plus
Subject: NERC - RSG - Whitepaper discussion

As discussed at the RSG meeting on January 12, here is the meeting information for the whitepaper discussion on regional variances and standards. I will forward the latest version after I have removed the process information from the document, limiting our discussion to just the definition of regional variances and standards.

Access code = 6512269
Passcode = 075990

Howard Gugel
Manager of Regional Standards
NERC
(609) 651-2269
howard.gugel@nerc.net<mailto:howard.gugel@nerc.net>

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[cid:image001.gif@01CCD5C4.2E3B0D30]<http://www.readytalk.com>

NERC - RSG - Whitepaper discussion
You have been invited to a ReadyTalk Meeting hosted by Howard Gugel. All the information you need to join is below.

Step 1: Dial-In

[cid:image002.gif@01CCD5C4.2E3B0D30]

U.S. & Canada: 866.740.1260

[cid:image003.gif@01CCD5C4.2E3B0D30]

Access Code: 6512269

Step 2: Web Login

[cid:image004.gif@01CCD5C4.2E3B0D30]<https://cc.readytalk.com/r/xs3skr20zwa6>

https://cc.readytalk.com/r/xs3skr20zwa6

[cid:image003.gif@01CCD5C4.2E3B0D30]<https://cc.readytalk.com/r/xs3skr20zwa6>

Security Passcode: 075990

Details

Date:

Fri, Feb 3, 2012

Time:

11:00 AM EST

Duration:

2 hours

Host(s):

Howard Gugel

Add to your Calendar

[cid:image005.gif@01CCD5C4.2E3B0D30]

Outlook Calendar<https://cc.readytalk.com/cc/schedule/iCalCreation.do?eventId=yf5m60lwfzgw>

[cid:image006.gif@01CCD5C4.2E3B0D30]

Lotus Notes Calendar<https://cc.readytalk.com/cc/schedule/lotusNotesInfo.do>

[cid:image007.gif@01CCD5C4.2E3B0D30]

Google Calendar<https://cc.readytalk.com/gcal/c/xs3skr20zwa6>

ReadyTalk Support Information

Test your computer<http://test.readytalk.com> for compatibility prior to the meeting.

For technical support:
U.S. and Canada: 800.843.9166
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Where to Put Requirements that Apply on Less Than a Continent-wide Basis

Regional Standards and Variances – *What was Approved in the ERO Certification Order and Rules of Procedure*

FERC has indicated it will consider approving regional differences (variances) and Regional Standards that meet the following criteria:

Item 34: ¶ 274 of the ERO Certification Order:

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

The FERC-approved definitions of Regional Standard and Variance (from the Rules of Procedure) are:

> **"Regional reliability standard"** means a type of reliability standards that is applicable only within a particular regional entity or group of regional entities. A regional reliability standard may augment, add detail to, or implement another reliability standard or cover matters not addressed by other reliability standards. Regional reliability standards, upon adoption by NERC and approval by the applicable ERO governmental authority(ies), shall be reliability standards and shall be enforced within the applicable regional entity or regional entities pursuant to delegated authorities.
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> **"Variance"** means an aspect or element of a reliability standard that applies only within a particular regional entity or group of regional entities, or to a particular entity or class of entities. A variance allows an alternative approach to meeting the same reliability objective as the reliability standard, and is typically necessitated by a physical difference. A variance is embodied within a reliability standard and as such, if adopted by NERC and approved by the ERO governmental authority, shall be enforced within the applicable regional entity or regional entities pursuant to delegated authority.

Regional Standards and Variances – *What was Approved in the Standard Processes Manual*

The latest approved version of the Standard Processes Manual includes the following language:

> NERC's drafting teams shall aim to develop standards with requirements that apply on a continent-wide basis, minimizing the need for variances while still achieving the standard's reliability objectives. If one or more requirements cannot be met or complied with as written because of a physical difference in the bulk power system or because of an operational difference (such as a conflict with a Federally or Provincially approved tariff), but the requirement's reliability objective can be achieved in a different fashion, an entity or a group of entities may pursue a variance from

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one or more requirements in a continent-wide standard. It is the responsibility of the entity that needs a variance to identify that need and initiate the processing of that variance through the submittal of a SAR that includes a clear definition of the basis for the variance.

There are two types of variances – those that apply on an interconnection-wide basis, and those that apply to one or more entities on less than an interconnection-wide basis.

Interconnection-wide Variances

Any variance from a NERC reliability standard requirement that is proposed to apply to responsible entities within a regional entity organized on an interconnection-wide basis shall be considered an Interconnection-wide Variance and shall be developed through that regional entity's NERC-approved regional reliability standards development procedure.

While an interconnection-wide variance may be developed through the associated Regional Entity standards development process, regional entities are encouraged to work collaboratively with existing continent-wide drafting team to reduce potential conflicts between the two efforts.

An Interconnection-wide Variance from a NERC reliability standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the associated NERC reliability standard. NERC shall rebuttably presume that an Interconnection-wide Variance from a NERC reliability standard that is developed, in accordance with a standards development procedure approved by NERC, by a regional entity organized on an interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

Variances that Apply on Less than an Interconnection-wide Basis

Any variance from a NERC reliability standard requirement that is proposed to apply to one or more entities but less than an entire Interconnection (e.g., a variance that would apply to a regional transmission organization or particular market or to a subset of bulk power system owners, operators, or users), shall be considered a Variance. A Variance may be requested while a standard is under development or a Variance may be requested at any time after a standard is approved. Each request for a Variance shall be initiated through a SAR, and processed and approved in the same manner as a continent-wide standard, using the standards development process defined in this manual.

Regional Standards and Variances - *Requirements that Apply on Less than a Continent-wide Basis*

NERC's goal is to have a set of reliability requirements that provides an 'adequate level of reliability.' In some instances, a continent-wide standard cannot be written so that the desired level of reliability is attained with requirements that apply to all entities – in some instances an alternative requirement that mandates performance not addressed in the continent-wide requirements is needed to attain the desired level of reliability – and in some instances requirements with more stringent performance are needed to maintain an adequate level of reliability. Regional standards and variances give NERC the tools it needs to develop and maintain a core set of standards that apply throughout the continent – augmented by a small set of supplementary requirements that address unique situations where a continent-wide requirement is not necessary.

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FERC, in its Orders, has indicated that it will apply a single set of criteria for approving both Regional Standards and Regional Differences.

Since all standards approved by NERC and applicable regulatory authorities are subject to the same level of enforceability – the location of a requirement (in a regional standard or a continent-wide standard) does not have any impact on either reliability or enforceability.

There are three ways of developing a requirement that identifies performance necessary for reliability that applies on less than a continent-wide basis:

- Within a continent-wide standard, a requirement can include alternative performance based on different facility characteristics, different regions, or different interconnections. (See INT-006-3 for an example.)
- A continent-wide standard can include a variance that specifies one or more alternative requirements that apply to a functional entity meeting certain characteristics[GVZ1], one or more Regions, or an Interconnection. (See FAC-011-2 for an example.)
- A regional standard ~~can~~will include mandatory ~~performance~~requirments that achieve a reliability objective ~~that is~~ needed for reliability ~~only~~ in that region. (See VAR-STD-002b-1 for an example.)

Each of these methods achieves the same goal – that of developing a requirement that specifies mandatory ~~performance~~requirments needed ~~for~~to achieve a reliability objective.

The process of developing and approving standards that apply on a Regional or Interconnection-wide basis differs from the process used to develop a continent-wide standard. ~~Typically, standards developed on a continent-wide basis are subject to more scrutiny because there is a broader population reviewing and providing comments on a continent-wide standard.~~ [GVZ2]

~~With limited resources to allocate to standard development, developing regional standards and continent-wide standards requiring very similar performance is not desired~~[GVZ3]. When a continent-wide standard is developed and there is a need to support the continent-wide standard with region-specific requirements, the region-specific requirements may be developed either as regional standards or ~~the regional performance can be embedded within the continent-wide standard's requirements~~a regional variance to the continent wide standard requirement. If it is determined that a variance is necessary, the development of the variance should occur during the development of the continent wide standard, if possible. ~~[COMMENT: Consider adding that the latter approach is preferred, if the region-specific need is identified while the CW standard is under development~~[GVZ4]~~.] In some cases, regional requirements that identify 'how' to implement a continent-wide standard may be developed as regional procedures rather than Regional Standards.~~[HLG5]

Some Regions have technical committees that study reliability issues and identify areas where new or different reliability requirements may be needed. If an region identifies a potential reliability "gap" it will take the necessary steps to fill that gap with either a Regional Standard~~, Criteria~~ or Variance with due consideration to NERC's existing projects and the ability of those projects to address the need. Before embarking on an effort to develop a set of requirements for a new regional standard, it would be beneficial to ~~determine~~ consider if the new/revised requirement should apply on a broader basis – to other regions, to an entire Interconnection, or to the entire continent. ~~[COMMENT: Most of the subjects for regional standards that have been recently discussed in Texas would apply equally on a continent-wide basis, and they arise out of frustration with the pace of CW standard development, along with a different view on the priority of various reliability gaps. Should this document provide guidance on whether it is appropriate for a regional standard to address a continent-wide issue just to~~

~~get it done faster[GVZ6]?]~~This endeavor should not preclude the region from addressing any reliability related need, especially in the event NERC lacks sufficient resources to develop the continent wide standard, or Interconnection wide standard.[HLG7]

When a region posts a proposed regional SAR for comment, they will send a notification of that posting to NERC staff. NERC will then send a notification of the posting to industry stakeholders informing them of the region's desire to obtain comments on the proposed regional SAR. (should the comment form have a question about whether the SAR should apply on a footprint larger than the region?) ~~The Regional Standards Group (RSG) could support posting proposals for new/revised requirements that may apply on less than a continent-wide basis and solicit continent-wide stakeholder feedback on the scope of the reliability related need for the new/revised requirements.~~ [HLG8][COMMENT: We would not support posting regional standards for continent-wide substantive feedback. As a single interconnection region, with a unique set of technical and market rules, we do not think soliciting comments from outside of the region would be helpful. Of course, anyone can submit comments during our regional posting periods[GVZ9].]

~~As envisioned, a proposal for new/revised requirements would be posted for an informal 30-day comment period with a webinar conducted during that comment period. The posting would consist of a 'Technical Concepts' paper that includes a description of the proposed new/revised requirements and a summary of the technical work done accompanied by a comment form. The comment form would, as a minimum, identify whether stakeholders agree that there is a need for a new/revised requirements; whether the requirements should apply on a regional, interconnection, or continent-wide basis; and whether stakeholders agree that the technical work done is sufficient, or believe additional work is needed before developing the requirements. NERC staff would assemble the comments and share them with both the RSG and the Standards Committee.~~ [HLG10][See above comment.]

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If ~~stakeholders~~ it is determined that the proposed requirements should apply on a continent-wide basis and the technical justification already developed by the Region is applicable on a continent-wide basis, then the Region should work with the Standards Committee to identify a priority[GVZ11] for developing the standard before starting development of the Regional Standard[GVZ12].

- If the new standard is closing an identified gap in reliability, then it should [GVZ13]receive a high priority and development should start within a timeframe acceptable to the sponsoring Region.[HLG14]
- If the Standards Committee cannot commit to starting the project in a time frame acceptable to the sponsoring Region (either because the priority is not high enough or because there are already too many projects under active development) then the sponsoring Region should proceed with developing the standard as a Regional Standard.[HLG15] [COMMENT: This encourages a Region to move forward simply because the NERC process is too slow – other places in this document discourage such action.]
- The Standards Committee should make a commitment to use the work done in developing the Regional Standard as a starting point for developing the continent-wide standard. [HLG16] [COMMENT: I don't think the SC can make such a commitment. The CW SDT may have very different views from the regional SDT. See recent experience with the rapid development project.]

If the technical justification developed by the Region is applicable to a subset of the continent, and additional time is needed to determine if the requirements should apply on a continent-wide basis, the RSG should coordinate its actions [what role/authority does the RSG have in connection with this process?] with the Standards Committee before starting development of the Regional Standard.[HLG17]

- The Standards Committee should work with NERC's technical committees to develop the technical justification for the continent-wide requirements and report to the RSG [??] on the proposed timeline for development of any necessary technical justification.[HLG18]
- If the sponsoring Region needs enforceable requirements before a determination is made on whether the proposed requirements should apply on a continent-wide basis, then the Region should proceed with developing the standard as a Regional Standard.
- If a determination is made that the requirements should apply on a continent-wide basis, the Standards Committee should make a commitment to use the work done in developing the Regional Standard as a starting point for developing the continent-wide standard. [See above.]

If ~~stakeholders determine~~ the applicable authority determines that the proposed new/revised requirements are needed for reliability and should apply on less than a continent-wide basis and less than an Interconnection-wide basis, then the ~~RSG~~ NERC staff should work with the sponsoring Region to consider the best method of approaching development of that standard – as a variance to a continent-wide standard or as a regional standard. In making this determination, the ~~RSG~~ Region should consider FERC's differentiation between variances and regional standards.[HLG19]

- If new requirements address a topic not covered in a continent-wide standard, then the new requirements should be developed as a "Regional Standard" following the Regional Standards Development Process.
- If new requirements are more stringent or cover an aspect of a topic already addressed in a continent-wide standard, then the new requirements should be proposed as a Variance to the continent-wide standard. To initiate development of a Variance, the Region or entity wanting the Variance must submit the Variance, the technical justification for the Variance, and a SAR to the NERC Standard Process Manager. The ~~RSG~~ Region should work with the Standards Committee to identify a priority for developing the Variance. [COMMENT: This seems to assume that any Variance would be developed under a NERC process. That view improperly leaves out regional development of variances, which is covered by our FERC-approved regional process.]

If ~~stakeholders~~ the applicable authority determines that the proposed new/revised requirements are needed for reliability [HLG20]and should apply on an Interconnection-wide basis, and the Interconnection does not have a NERC approved single Regional Standards Development Process that is applicable to the entire Interconnection, then that Interconnection should develop the Interconnection-wide Variance using the continent-wide standard development process. (Submit the Variance, the technical justification for the Variance, and a SAR to the NERC Standard Processes Manager and then work with the Standards Committee to establish a priority for the project.)

If ~~stakeholders~~ the applicable authority determines that the proposed new/revised requirements are needed for reliability and [HLG21]should apply on an Interconnection-wide basis, and the Interconnection has a single NERC--approved Regional Standards Development Process, then that Interconnection should develop the Interconnection-wide Variance using its Standard Development Process.

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If "new" requirements address an activity that is:	And the standard is:	And the standard applies to:	Then the standard belongs in:	With the standard developed following:
Addressed in continent-wide standard	More stringent than continent-wide requirement	An entire Interconnection	Interconnection-wide variance to continent-wide standard	SAR submitted through continent-wide process Not correct. This table needs work. Depends on whether interconnection is single-region, etc.
	Different method of achieving same reliability goal; difference necessary for physical difference or other reason	A Region, set of Regions, or a specific set of functional entities	Less than interconnection-wide variance to continent-wide standard	
Not addressed in continent-wide standard	Not needed for reliability on a continent-wide basis	A ~~n entire~~ multi-region Interconnection[HLG22]	Interconnection-wide standard	Interconnection-wide regional standard process (does such a thing exist?)
		A single Region	Regional Standard	Regional standard process
	Needed for reliability on a continent-wide basis	Entire continent	Continent-wide standard	Continent-wide standard process

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Requesting a Variance to a Continent-wide Standard

The Standard Processes Manual clarifies that there are two types of variances – those that apply to an entire interconnection and those that apply to entities on a less than interconnection-wide basis.

When any request for a Variance to a continent-wide standard is submitted with a SAR, the request should include the following:

- A technical justification for the variance suitable for posting so that all stakeholders understand the need for the variance[HLG23]
- A statement indicating whether the proposed requirement is "in addition to" or "an alternative to" one or more specific requirements in the continent-wide standard
- For each requirement proposed, the associated Violation Risk Factor, Time Horizon, Measure, Evidence Retention, and set of Violation Severity Levels

Retiring or Revising Regional Standards to Avoid Duplication or Conflict with Continent-wide Standards:[HLG24]

When a continent-wide standard is developed and addresses the same topic as addressed in a Regional standard, an ~~joint~~ implementation plan that considers approved regional plans is needed to ensure stakeholders are not accountable for performance with two different requirements addressing the same performance at the same time.[HLG25]

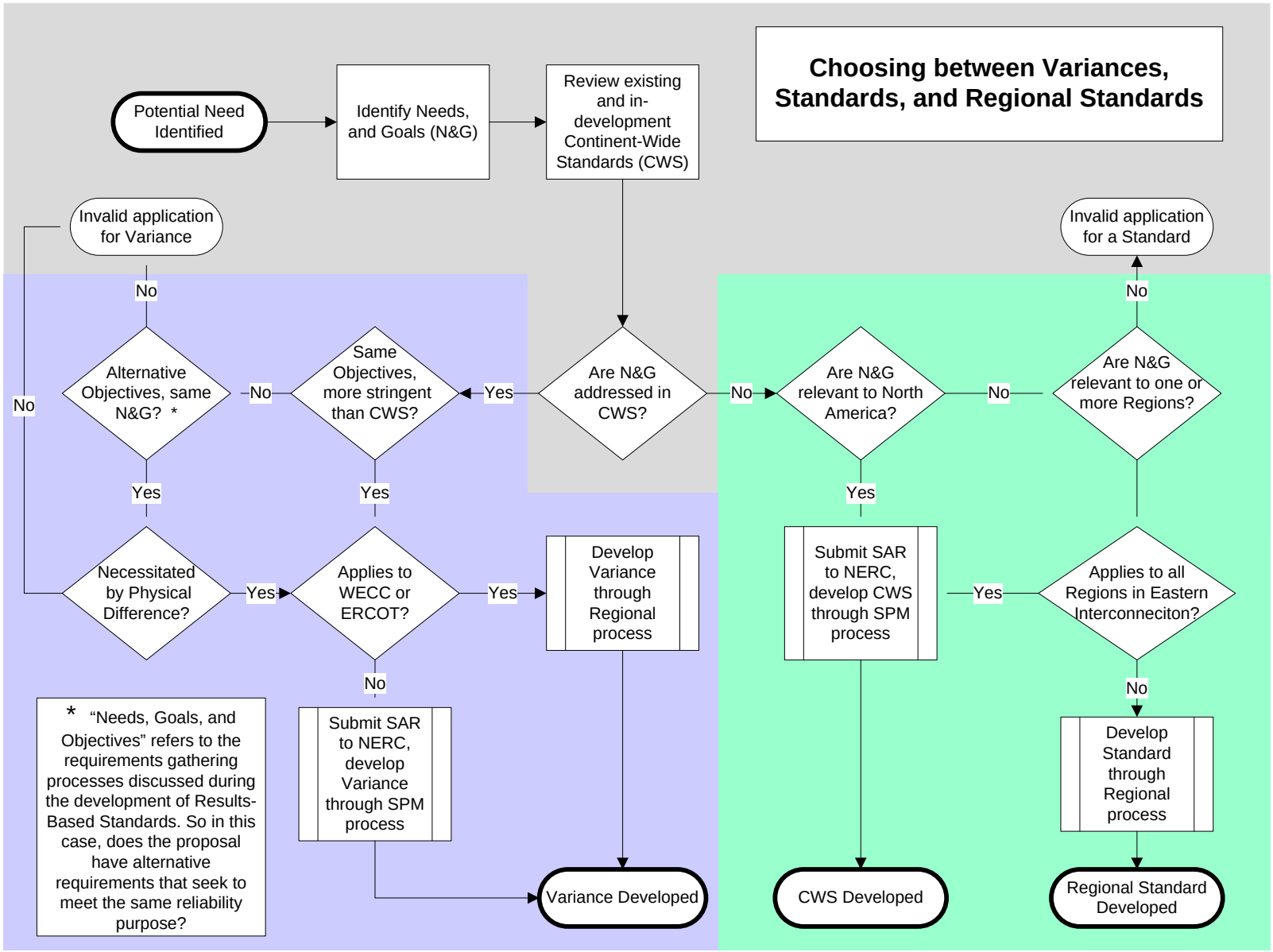
- If the performance in the Regional Standard is more stringent than the performance in the continent-wide standard, then the Regional Standard should be absorbed into the continent-wide standard with the more stringent requirements addressed either in a table (similar to the tables in INT-006-3) or as a variance to the continent-wide standard.[HLG26]
- If the continent-wide standard addresses some but not all of the performance in the Regional Standard, then on a case-by-case basis, the Region, working with the continent-wide drafting team, should determine what to do with the requirements that identify performance not included in the continent-wide standard. Acceptable choices include:
    - Revising the Regional Standard to remove only the requirements duplicated in the continent-wide standard;
    - Moving requirements that explain 'how' into a regional procedure, or
    - Adding requirements from the Regional Standard into the continent-wide standard in the form of a Regional Variance.[HLG27]
- If the performance in the Regional Standard is less stringent than the performance in the continent-wide standard, then the Regional Standard must be retired at the time that the continent-wide standard goes into effect.[HLG28]

Proposals:

1. The language in the Standard Processes Manual allows a broader range of variances than identified in the Rules of Procedure. The language in the Rules of Procedure should be modified to align more closely with the language in the SPM.[HLG29]

2. The Standards Committee should add criteria to its prioritization tool to encourage the development of variances as opposed to regional standards [As defined above, regional standards and variances are used in different circumstances; one should not be "encouraged" over the other.] and should give priority to these proposals to minimize the Regions' needs to develop Regional standards that will later be displaced by continent-wide standards addressing the same topic. [This seems to assume that variances will be developed by CW SDTs rather than on a regional basis. I'm not sure that is correct, especially for Texas and WECC.][HLG30]
3. The Regional Standards Group should seek stakeholder feedback on a continent-wide basis for all proposed regional standards at the project proposal stage. [Oppose.][HLG31]

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Choosing between Variances, Standards, and Regional Standards
Potential Need Identified
Identify Needs, and Goals (N&G)
Review existing and in-development Continent-Wide Standards (CWS)
Are N&G addressed in CWS?
Yes
No
Are N&G relevant to North America?
No
Yes
Are N&G relevant to one or more Regions?
No
Yes
Same Objectives, more stringent than CWS?
No
Yes
Alternative Objectives, same N&G? *
No
Yes
Necessitated by Physical Difference?
No
Yes
Applies to WECC or ERCOT?
Yes
No
Applies to all Regions in Eastern Interconneciton?
Yes
No
Develop Variance through Regional process
Submit SAR to NERC, develop Variance through SPM process
Submit SAR to NERC, develop CWS through SPM process
Develop Standard through Regional process
Invalid application for Variance
Invalid application for a Standard
Variance Developed
CWS Developed
Regional Standard Developed
* "Needs, Goals, and Objectives" refers to the requirements gathering processes discussed during the development of Results-Based Standards. So in this case, does the proposal have alternative requirements that seek to meet the same reliability purpose?

Whitepaper to provide guidance on Regional Standards and Variances

Regional Standards and Variances - *Requirements that Apply on Less than a Continent-wide Basis*

NERC's goal is to have a set of reliability requirements that provides an 'adequate level of reliability.' In some instances, a continent-wide standard cannot be written so that the desired level of reliability is attained with requirements that apply to all entities – in some instances an alternative requirement that mandates performance not addressed in the continent-wide requirements is needed to attain the desired level of reliability – and in some instances requirements with more stringent performance are needed to maintain an adequate level of reliability. Regional standards and variances give NERC the tools it needs to develop and maintain a core set of standards that apply throughout the continent – augmented by a small set of supplementary requirements that address unique situations where a continent-wide requirement is not necessary.

FERC, in its Orders, has indicated that it will apply a single set of criteria for approving both Regional Standards and Regional Differences.

Since all standards approved by NERC and applicable regulatory authorities are subject to the same level of enforceability – the location of a requirement (in a regional standard or a continent-wide standard) does not have any impact on either reliability or enforceability.

There are three ways of developing a requirement that identifies performance necessary for reliability that applies on less than a continent-wide basis:

- Within a continent-wide standard, a requirement can include alternative performance based on different facility characteristics, different regions, or different interconnections. (See INT-006-3 for an example.)
- A continent-wide standard can include a variance that specifies one or more alternative requirements that apply to a functional entity meeting certain characteristics, one or more Regions, or an Interconnection. (See FAC-011-2 for an example.)
- A regional standard will include mandatory requirements that achieve a reliability objective needed for reliability in that region. (See VAR-002-WECC-1 for an example.)

Each of these methods achieves the same goal – that of developing a requirement that specifies mandatory requirements needed to achieve a reliability objective.

When a continent-wide standard is developed and there is a need to support the continent-wide standard with region-specific requirements, the region-specific requirements may be developed either as a regional standard or a regional variance to the continent wide standard requirement. If it is determined that a variance is necessary, the development of the variance should occur during the development of the continent wide standard, if possible.

Some Regions have technical committees that study reliability issues and identify areas where new or different reliability requirements may be needed. If an region identifies a potential reliability "gap" it will take the necessary steps to fill that gap with either a regional standard or Variance with due consideration to NERC's existing projects and the ability of those projects to address the need. Before embarking on an effort to develop a set of requirements for a new regional standard, it would be beneficial to consider if the new/revised requirement should apply on a broader basis – to other regions, to an entire Interconnection, or to the entire continent. This endeavor should not preclude the region from addressing any reliability related need, especially in the event NERC lacks sufficient resources to develop the continent wide standard, or Interconnection wide standard.

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A regional standard either augments (i.e. is more stringent, more specific, or facilitates) a continent wide standard or addresses a subject for which there is no continent wide standard. If the regional standard augments a continent wide standard, the regional standard typically contains more specific requirements. Responsible Entities are technically audited on both standards, and must meet all of the requirements of both standards.

A regional Variance is something that achieves the reliability objective of the continent wide standard's requirement(s) in a "different" or alternate way than specified in a given requirement in the continent wide standard. Also, for those regions that are not arranged on an interconnection wide basis, the development of the regional Variance may be quite difficult, since it must be developed and approved using the continent wide process. It may be hard to justify why one Region in the Eastern Interconnection would need a Variance and another Region does not. In these instances, a regional standard might be the better approach towards addressing identified reliability gaps or concerns.

Regional standards are developed using the Region's FERC approved standard development process. Regional Variances, on the other hand, have a couple of development paths. If the need for the regional Variance is identified during the development of the continent wide standard, the Variance is developed by the continent wide Standard Drafting Team and follows the NERC standard development process along with the rest of the standard. If the regional Variance is developed after the continent wide standard is developed, then the process by which the regional variance is developed is up to the Region, then later, depending on whether it is interconnection wide or not, would enter the continent wide NERC process.

Background Information

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reliability standards. Regional reliability standards, upon adoption by NERC and approval by the applicable ERO governmental authority(ies), shall be reliability standards and shall be enforced within the applicable regional entity or regional entities pursuant to delegated authorities.

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While an interconnection-wide variance may be developed through the associated Regional Entity standards development process, regional entities are encouraged to work collaboratively with existing continent-wide drafting team to reduce potential conflicts between the two efforts.

An Interconnection-wide Variance from a NERC reliability standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the associated NERC reliability standard. NERC shall rebuttably presume that an Interconnection-wide Variance from a NERC reliability standard that is developed, in accordance with a standards development procedure approved by NERC, by a regional entity organized on an interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

Variances that Apply on Less than an Interconnection-wide Basis

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one or more requirements in a continent-wide standard. It is the responsibility of the entity that needs a variance to identify that need and initiate the processing of that variance through the submittal of a SAR that includes a clear definition of the basis for the variance.

There are two types of variances – those that apply on an interconnection-wide basis, and those that apply to one or more entities on less than an interconnection-wide basis.

Interconnection-wide Variances

Any variance from a NERC reliability standard requirement that is proposed to apply to responsible entities within a regional entity organized on an interconnection-wide basis shall be considered an Interconnection-wide Variance and shall be developed through that regional entity's NERC-approved regional reliability standards development procedure.

While an interconnection-wide variance may be developed through the associated Regional Entity standards development process, regional entities are encouraged to work collaboratively with existing continent-wide drafting team to reduce potential conflicts between the two efforts.

An Interconnection-wide Variance from a NERC reliability standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the associated NERC reliability standard. NERC shall rebuttably presume that an Interconnection-wide Variance from a NERC reliability standard that is developed, in accordance with a standards development procedure approved by NERC, by a regional entity organized on an interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

Variances that Apply on Less than an Interconnection-wide Basis

Any variance from a NERC reliability standard requirement that is proposed to apply to one or more entities but less than an entire Interconnection (e.g., a variance that would apply to a regional transmission organization or particular market or to a subset of bulk power system owners, operators, or users), shall be considered a Variance. A Variance may be requested while a standard is under development or a Variance may be requested at any time after a standard is approved. Each request for a Variance shall be initiated through a SAR, and processed and approved in the same manner as a continent-wide standard, using the standards development process defined in this manual.

Regional Standards and Variances - *Requirements that Apply on Less than a Continent-wide Basis*

NERC's goal is to have a set of reliability requirements that provides an 'adequate level of reliability.' In some instances, a continent-wide standard cannot be written so that the desired level of reliability is attained with requirements that apply to all entities – in some instances an alternative requirement that mandates performance not addressed in the continent-wide requirements is needed to attain the desired level of reliability – and in some instances requirements with more stringent performance are needed to maintain an adequate level of reliability. Regional standards and variances give NERC the tools it needs to develop and maintain a core set of standards that apply throughout the continent – augmented by a small set of supplementary requirements that address unique situations where a continent-wide requirement is not necessary.

DRAFT

FERC, in its Orders, has indicated that it will apply a single set of criteria for approving both Regional Standards and Regional Differences.

Since all standards approved by NERC and applicable regulatory authorities are subject to the same level of enforceability – the location of a requirement (in a regional standard or a continent-wide standard) does not have any impact on either reliability or enforceability.

There are three ways of developing a requirement that identifies performance necessary for reliability that applies on less than a continent-wide basis:

- Within a continent-wide standard, a requirement can include alternative performance based on different facility characteristics, different regions, or different interconnections. (See INT-006-3 for an example.)
- A continent-wide standard can include a variance that specifies one or more alternative requirements that apply to a functional entity meeting certain characteristics, one or more Regions, or an Interconnection. (See FAC-011-2 for an example.)
- A regional standard will include mandatory requirements that achieve a reliability objective needed for reliability in that region. (See VAR-STD-002b-1 for an example.)

Each of these methods achieves the same goal – that of developing a requirement that specifies mandatory requirements needed to achieve a reliability objective.

When a continent-wide standard is developed and there is a need to support the continent-wide standard with region-specific requirements, the region-specific requirements may be developed either as a regional standard or a regional variance to the continent wide standard requirement. If it is determined that a variance is necessary, the development of the variance should occur during the development of the continent wide standard, if possible.

Some Regions have technical committees that study reliability issues and identify areas where new or different reliability requirements may be needed. If an region identifies a potential reliability "gap" it will take the necessary steps to fill that gap with either a regional standard or Variance with due consideration to NERC's existing projects and the ability of those projects to address the need. Before embarking on an effort to develop a set of requirements for a new regional standard, it would be beneficial to consider if the new/revised requirement should apply on a broader basis – to other regions, to an entire Interconnection, or to the entire continent. This endeavor should not preclude the region from addressing any reliability related need, especially in the event NERC lacks sufficient resources to develop the continent wide standard, or Interconnection wide standard.

A regional standard either augments (i.e. is more stringent, more specific, or facilitates) a continent wide standard or addresses a subject for which there is no continent wide standard. If the regional standard augments a continent wide standard, the regional standard typically contains more specific requirements. Responsible Entities are technically audited on both standards, and must meet all of the requirements of both standards. In most instances, if a Responsible Entity meets the requirements of the regional standard, it will by default meet the requirements of the less stringent continent wide standard.

A regional Variance is something that achieves the reliability objective of the continent wide standard 's requirement(s) in an "different" or alternate way than specified in a given requirement in the continent wide standard. For example, any requirement in a continent wide standard that specifies "adjacent Balancing Authority" is not possible in the Texas Reliability Entity footprint, so an "alternate" way of accomplishing the reliability objective of that requirement could be accomplished in a regional Variance.

DRAFT

Also, for those regions that are not arranged on an interconnection wide basis, the development of the regional Variance may be quite difficult, since it must be developed and approved using the continent wide process. It may be hard to justify why one Region in the Eastern Interconnection would need a Variance and another Region does not. In these instances, a regional standard might be the better approach towards addressing identified reliability gaps or concerns.

Regional standards are developed using the Region's FERC approved standard development process. Regional Variances, on the other hand, have a couple of development paths. If the need for the regional Variance is identified during the development of the continent wide standard, the Variance is developed by the continent wide Standard Drafting Team and follows the NERC standard development process along with the rest of the standard. If the regional Variance is developed after the continent wide standard is developed, then the process by which the regional variance is developed is up to the Region, then later, depending on whether it is interconnection wide or not, would enter the continent wide NERC process.

DRAFT

From:	Gerard J. Dunbar
To:	Guy V. Zito
Cc:	Lee R. Pedowicz
Subject:	Meeting Notes.....SCPS.....SC.....RSG.....January 10, January 11, January 12
Date:	Thursday, January 12, 2012 8:44:44 PM

Tuesday January 10, 2012 ……Standards Committee Process Subcommittee (SCPS):

Administrative:

- Jason Shaver and Pat Brown leaving SCPS.

Agenda Item 1a:

- Process for use of Drafting Teams to assist in developing RSAWs (Audit Worksheets):

  A small group will be formed comprised of Standards Staff and Compliance Staff to develop an approach that would ultimately be presented to the SC.

  The SCPS discussed this item in the context of the possibility of eventually eliminating Measures from the Standards…..the idea being that if the RSAW is precisely written a Measure will not be required.

Agenda Item 1b:

- Process for replacing an appointed drafting team member:

  David Kiguel led the discussion.

  The SCPS made some changes to the draft document…….significantly they removed the questionnaire and revised language in the guidelines……they agreed to leave the obstruction issue but moved it.

Agenda Item 1c:

- Rapid Revision process…….the SCPS discussed proposing a **single portal concept**…….where NERC will triage a request and decide whether a request is resolved as either a CAN, an Interpretation, Rapid Revision, or Standard Development.

Agenda Item 2a:

- Prioritizing CAN's:

  SCPS reviewed a tool developed by Linn Oelker for prioritizing CAN's ……very similar to tool developed to prioritize standard development…….only the criteria has been

changed……..will be introduced to the SC.

Agenda Item 2a:

- Proposal to eliminate the Quality Review Advisory Working Group (QRAWG)…..SCPS does not support eliminating……NERC staff will present the proposal to the SC….

  Next meeting ……Tampa April 10th……..Ben recommending a full day meeting since he was not able to get to all agenda items.

Wednesday January 11, 2012…..Standards Committee Day 1:

Note: See separate notes on Alternative Standard Development Procedure

Summary of high priority projects.

- BES on track to go the NERC BOT on 1/18…..and on schedule to be presented to FERC.

- 6 Projects on schedule.
  7 Projects behind schedule.

- Herb commented that NERC will occasionally hold back posting a standard if too many standards are posted at one time…..that can lead to a project falling behind…..Herb keeps Allan Mosier informed of these circumstances……NERC refers to these situations as 'posting constraints'.

- SC had a long discussion on PRC -005……..the importance of the standard and the number of violations (high)….Charles Rogers SDT chair called in……PRC -005 narrowly failed the recirc. ballot last summer and a new ballot pool was formed according to procedure…..significant drop in approval on initial ballot of new ballot pool seems to be related to the new ballot pool members…..Charles Rogers optimistic and expects a successful ballot….Allen Mosier recommending a Technical Conference …..Carol Sedewitz, suggested a regional Technical Conference…..

- Project 2007-12 Frequency response……SC endorsed revised schedule… ongoing concern over the BA being held responsible for frequency response if they don't own the asset…..

Update on outstanding Interpretations…….

- Interpretation on the definition of a 'single point of failure'……. submitted in Dec . 2011 for TPL 003 and TPL 004…Carol Sedewitz concern…….there is an existing NERC data request that is looking for information on the same issue……..concern over available resources to answer data request and develop the Request for Interpretation on this same issue…..also there is the potential for the issue to become tangled in the TPL standard which is

currently before FERC…..

Candidates for Rapid Revision…..

- SC had a lengthy discussion on two FMPP interpretatations of existing TOP standards …… existing body of TOP standards are currently being balloted…..FMPP concern is addressed in the current balloted standards…..concern though is that successive ballots and recirc. Ballot and NERC and FERC approvals and implementation plan could take a very long time….intent with the rapid revision is to make focused changes on the existing body of standards…interpretation of TOP002 is more involved and would not be a good candidate for a rapid revision……SC approved a motion for a rapid revision of TOP-006…

  Also another interpretation request for a VAR standard…….no team in place…but SC approved motion to move the VAR standard to a Rapid Revision process.

Mike Gildea asked for a discussion on the status of Results Based Standards…..

- Mike is concerned that it seems to no longer be a priority with NERC……Herb and Andy Rodriguez countered that despite the fact that no one is talking about them results based standards has been internalized at NERC and is still very much how they approach standard development…..FAC 003 Veg. Man. currently before FERC and the first NERC BOT approved results based standard will be the acid test since NERC will receive FERC comments on results based…..Herb agreed to post on the NERC website a list of those standards that are being developed as results based….

Jim Castle presented on behalf of the NAESB Business Practices Sub Committee

- Jim requested NERC to elevate the priority of Interchange Standard Development in order to support conforming changes in the NAESB business practice efforts……intra BA transactions need to be tagged… limited modifications for IRO-006-East -1…..

  NAESB can move ahead with the business practice…….Operating Reliability Subcommittee (ORS) needs to identify any reliability gaps…….no SC action at this time…

Ben Li reviewed the CAN priority tool…….(see SCPS notes on the CAN priority tool above.)

- SC approves this approach and will send to other standing committees (CCC)for their action.

SC heard NERC staff proposal to eliminate the Quality Review Advisory Working Group (QRAWG) …..

- QRAWG provides administrative oversight on behalf of the SC……NERC would like the SC Exec Comm. will now provide this oversight… extended discussion among the SC……many felt that the QRAWG provides value….

SC approved motion to eliminate QRAWG but assign staff to bring significant issues to the SC Exec Comm.

Thursday January 12, 2012…..Standards Committee Day 2:

- Carol Sedewitz, Frank McElvain and Steve Rueckert appointed to the SC nominating committee for the SC Executive Board.
  Above nominating committee presented the following slate to serve as at large members on the SC Exec Comm.: David Kiguel, Jason Shaver, and John Bussman.

- Top priority Standards for 2012 : CIP, BES Phase 2, 3 Part Communication, PRC and Frequency Response

- Proposed SC initiatives to align with 7 broad ERO goals: Maureen Long to distribute

- Linda Campbell on behalf of the SCPS……..development of a plan to allow RSAWs to be developed by the SDT……a Working Group, comprised of Compliance, Standards and NERC lawyers will develop the plan……when developed the plan will be submitted to the NERC BOT…..other questions to be answered …..do we eliminate Measures?…..do the RSAW's go to FERC when the standard is approved?....SC approved motion for WG to develop plan and present the plan to the SC.

- Maureen Long on behalf of the SCPS reviewed a plan to develop a Rapid Revision Process…….via a single portal process NERC would triage the request to determine if a question on some aspect of a standards requirements should be resolved either by Rapid Revision, CAN, Interpretation or Standard Development Process….. MOD 28 was handled in this manner and resolved via a Rapid Revision…

  Two motions approved by the SC……develop a formal Rapid Revision Procedure…..and develop a formal Triage Process.

- Ben Li on behalf of the Standards Committee Process Subcommittee……

  Presented red lined document on the Standard Drafting Team Scope…
  SC approved motion to accept proposed revisions.

  Two vacancies on the SCPS (Patrick Brown and Jason Shaver leaving)…….SC soliciting replacement candidates for the SCPS……Scott Miller volunteered……..

- Mike Gildea on behalf of the Communication and Planning Subcommittee….

Good feedback on the Weekly Standards Bulletin…considering some enhancements.

Two Standards and Compliance Workshops to be announced for 2012…….one in April and another in the Fall……..in between the two Workshops will be a Standards only 'State of the Standards' Webinar……..Webinar tentatively scheduled for July…..

- Laura Hussey discussion on the RBB……

RBB is cumbersome……NERC looking to verify that the existing RBB is comprised in a manner consistent with the Rules of Procedures. NERC will be looking to verify that affiliates are not represented by the same individual.

NERC also looking to verify existing affiliates.

NERC will be surveying members of the RBB between Feb and July to verify affiliates and representatives in order to verify integrity of voting process.

- Update on Regulatory:

Enforcement dates for Canadian entities will be updated shortly.

Regional UFLS Standards filed for SERC and TRE.

NERC submitted comments on the FERC NOPR for UFLS (continent wide).

David Kiguel commented on the recent Ontario rule that says the standards in Ontario are now effective when they become effective in the United States (FERC approval)…..as opposed to in the past upon NERC BOT approval.

- Update on the RSG (Herb):

MRO not supporting regional standards…..RFC on the fence…..Herb encouraged RFC to develop UFLS.

- I provided the SC with an update on the status of the NPCC Cost Effectiveness Procedure.

Motion for the SCPS to document the pros and cons of using the NPCC Cost Effectiveness Procedure and bring back a recommendation to the SC.

Thursday January 12, 2012…..Regional Standards Group Meeting:

- Review of Action Items:…..

    1. RSG Meeting Dates for 2012 distributed……item closed.
    2. Update Schedule for Protection System Mis-operations…..item closed.

- Update Rapid Development Project….Protection Systems Mis-Operations….45 day formal comment period expected in May…..Observation Report from Will Smith……(nothing to add).

- Agenda Item #8….**Action Item: Business Plan and Budget Common Assumptions 2013…. 8 Questions under Reliability Standards… NERC looking for a consensus responses …..**Howard to distribute Questions to the RSG……**regions will respond by Jan. 23 .**

- Agenda Item #9…Round Table Discussion….Discussion of Eastern Interconnect vs. Regional Standards…Will Smith to lead group reporting to the EMG…..group to explore the possibility of developing an (Eastern) Interconnection wide Standard…..Tuesday Jan. 17th @1pm (2 hrs)……initial conference call to discuss this concept…

- Howard will send out request for schedule updates(Development of Regional Standards).

- Agenda Item #11….discussion surrounding how the regions are posting their Regional Standards…..the NPCC approach…..once NERC BOT approves the standard the NPCC website will jump to the NERC website for current status and mandatory enforcement dates….suggested that all the Regions adopt a consistent approach…NERC website is improving in this regard……Provincial Dates were discussed at the SC and will be updated shortly.

- VRF Definitions and VSL Pro Forma Proposal…….conference call on Monday…….regions can participate.

- Agenda Item#13 Future RSG Dates….2/21 teleconference….3/12 teleconference…..4/13 Tampa.

- RFC has suspended the development of Regional Standards…..the issue is the impact of regional standards on multi regional entities

- FRCC, ERCOT, and SERC waiting for the DME continent wide before developing DME Regional Standard…..NERC and FERC pointed out that continent wide DME is not being actively developed….. FRCC, ERCOT, and SERC relying on regional criteria.

- Regional Standards and Variances…. ….concern about the SC telling a region how to prioritize development of a regional standard….. Howard Gugel whitepaper…….Howard and Don Jones will strip down the document and just answer the question of what is the

difference between a regional standard and a variance… the process language in the original document will be eliminated…..a conference call for the RSG on Feb. 3 will be scheduled to edit Howards and Don's product… once the RSG agrees on an answer to this question…… the RSG will report to the SC…..

Gerry Dunbar
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gdunbar@npcc.org

REGIONAL ENTITY	NERC RELIABILITY STANDARD	REGIONAL STANDARD	Status of Regional Standard			REGIONAL VARIANCE	VARIANCE FEASIBILITY	ACTION ITEM
			Approved	Under development	On Hold			
MRO	TPL-001	TPL-503-MRO-01 System Performance Requirements	Approved					
FRCC		MOD-024-FRCC-01 GenMW						
		MOD-025-FRCC-01 GenMW						
		PRC-002-FRCC-01 Regional Disturbance Monitoring and Reporting Requirements						
		PRC-003-FRCC-01 Regional Procedure for Analysis of Misoperation of Transmission and Generation Protection Systems						
		PRC-006-FRCC-01 Automatic Underfrequency Load Shedding Program						
		PRC-024-FRCC-01 Regional Generator Performance During Frequency and Voltage Excursions						
NPCC		BAL-002-NPCC-01 Regional Reserve Sharing Groups						
		PRC-002-NPCC-01 Disturbance Monitoring						
		PRC-006-NPCC-01 Automatic Underfrequency Load Shedding Program						
		PRC-012-NPCC-01 Special Protection Systems						
RFC		EOP-007-RFC-01 System Restoration Plans						
		BAL-002-RFC-02 Operating Reserves						
		BAL-502-RFC-02 Planning Resource Adequacy Analysis, Assessment and Documentation						
		MOD-024-RFC-01 Verification and Data Reporting of Generator Gross and Net Real Power Capability						
		MOD-025-RFC-01 Verification and Data Reporting of Generator Gross and Net Reactive Power Capability						

	PRC-002-RFC-01 Disturbance Monitoring and Reporting Requirements		
	PRC-006-RFC-01 Automatic Underfrequency Load Shedding		
	PRC-012-RFC-01 Special Protection Systems Requirements		
SERC	PRC-006-SERC-01 Automatic Underfrequency Load Shedding		
SPP	PRC-006-SPP-01 Automatic Underfrequency Load Shedding		
TRE	BAL-001-TRE-01 Primary Frequency Response in the ERCOT Region		
	IRO-006-TRE-01 IROL and SOL Mitigation in the ERCOT Region		
	PRC-006-TRE-01 Automatic Underfrequency Load Shedding		
WECC	BAL-001-0.1a WECC Viarance - Real Power Balancing Control Performance		Underdev
	BAL-002-WECC-01 Contingency Reserves (Order 740 Remand)		Underdev
	BAL-STD-002-0 Operating Reserves WECC Standard	Approved	
	BAL-004-WECC-02 Automatic Time Error Correction		Underdev
	BAL-004-WECC-1 Automatic Time Error Correction	Approved	
	IRO-STD-006-0 Qualified Path Unshceduled Flow Relief	Approved	
	PRC-STD-001-1 Certification of Protective Relay Application and Settings	Approved	
	PRC-STD-003-1 Protective Relay and Remedial Action Scheme Misoperation	Approved	
	PRC-STD-005-1 Transmission Maintenance	Approved	
	TOP-STD-007-0 Operating Transfer Capability	Approved	
	VAR-STD-002A-1 Automatic Voltage Regulators	Approved	
	VAR-STD-002B-1 Power System Stablizer	Approved	
	VAR-001-WECC-s Voltage and Reactive Control	Approved	

From:	Guy V. Zito
To:	rsg
Subject:	Points to report to the EMG on EI
Date:	Friday, February 03, 2012 4:35:29 PM
Importance:	High

Will et all,

Based on the call today and my suggestion, I think the EMG should receive a status report at their next meeting that includes the following at a minimum, (RSG feel free to comment).

*
RSG EI members are currently reviewing the status of in-process Regional Standards and Variances
*
RSG will be engaged in developing an EI Variance process for consideration by the Standards Committee Process Subcommitte with the goal of eventual inclusion into the NERC Standards Development Process.
*
RSG will formally review all new regional standards and variances within those Regions in the EI for potential to move them forward as either coordinated EI efforts looking for opportunities to move them forward or continent wide standards (CWS).
*
RSG will actively review the developing new proposals for CWS standards and provide input to more effectively promote the development of EI standards and variances, providing an alternative to regional standards if warranted.
*
RSC EI group is reviewing the regions arranged on an "Interconnection Wide" basis, i.e. TRE and WECC to look for efficiencies in developing interconnection wide standards and if there are any other lessons to be learned in developing variances and how to advance the efficiencies of those processes and how they may utilized and developed into an EI process.
*
RSC EI is also currently identifying potential difficulties and obstacles to EI variances and standards in order to understand what process issues may exist and how these may be addressed.
*
RSC EI also will develop a review process for NERC CWS standard being developed to ensure that any shortfalls or inadequacies will be addressed during the drafting of those standards to ensure potential regional and interconnection differences are identified early in the development process and communicated to the NERC standard drafting team SDT.

As was stated on the call, I think we need to chart out a course to address the concerns we are aware of. Peter H. will be at the EMG meeting and if there is some discussion around the EI status report and the expectation of deliverables of this group, then he will inquire as to further detail and a expectations for due date for completion. I think once we have affirmation of the above, a schedule for completion and project management will be possible. I think we should come to consensus on what is in the status report provided by Will. Comments welcome.

Thanks,

Guy V. Zito
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PROJECT PROPOSAL
Eastern Interconnection Standards Initiative

SHORT-TERM

Action Item	Objective/Description	Due Date
1	Derive format-based template(s) that shall be utilized going forward to incorporate regional variances into the NERC continent-wide standards.	
2	Each Regional Standards Process Manager (RSPM) or representative shall document within the attached excel spreadsheet the following: a. Identify Regional Standards (approved/underdevelopment/on-hold). b. Correlate Regional Standards to NERC Continent-wide Standards. c. Identify, document, and determine feasibility regional variances.	
3	Consolidated all information into one master document: a. Review information for accuracy. b. The RSG shall create a SAR for each of the NERC continent-wide standards that is requiring change; per the identified regional standards.	

LONG-TERM

Each region shall continue to have the ability to create Regional Standards. The Regional Standards Process Development Manual shall be maintained by the regional representatives. Going forward regional standards shall be developed and used as a temporary placeholder in lieu of the development of NERC continent-wide standards. At that time, the RSG will coordinate the development of a SAR, which shall be pushed up to the NERC Standards Committee for the development of the NERC continent-wide standard. This includes:

1. The fill-in-the-blank standards and any other priority standards not under development by the NERC standards drafting team, via the NERC Standards

Committees direction, shall be developed in the regions under the direction and guidance of the RSG regional representative.

a. The following are some suggested tools that both the regional representatives coordinating the effort and regional stakeholder standard drafting team members can utilize to provide efficiency and expedite the process:
    i. FERC Order – ensures content meets the purpose and intent and does not overreach what FERC has mandated.
    ii. Stakeholder Internal Procedures – establishes a commonly agreed upon knowledge base and confirms the effective application of the standards.
    iii. Stakeholder Compliance Evidence – establishes and provides examples of what is considered sufficient to demonstrate compliance to a specific NERC continent-wide standard and its associated requirements.
    iv. IEEE Standards and Recommendations – power utility industry specific stakeholder developed best practices. The regional and NERC continent-wide standards drafting team members can use aspects of the content to develop the standard and associated requirements.
    v. The Authoritative Dictionary of IEEE Standards Terms (IEEE 100), Seventh Edition by IEEE Standards Information Network/IEEE Press (Dec 1, 2000) – tool contains power utility (including reliability of the BES) specific terms developed and commonly understood by the industry stakeholders. Utilizing this tool reduces or eliminates the need to create new terms. Therefore, increasing the on-time deliverables associated with the development of NERC continent-wide standards.

From: Guy V. Zito
To: rsg
Subject: RE: Points to report to the EMG on EI
Date: Monday, February 06, 2012 11:20:48 AM

Don et al,

I think we need to give this more thought once we know the direction we are headed and have a concrete deliverable. I think the NERC process needs to be reviewed for a couple of reasons, primarily governance and balloting issues should this EI project move forward.

Although an EI standard could be viewed as a CWS with WECC and TRE variances, I don't think you want to head down that path because then the onus will be on TRE and WECC to demonstrate, perhaps technically and rigorously, why you guys are different. In this alternate approach we would only be seeking development and approval of the EI standard variance through this "alternate process" and hopefully confine it to something within the EI regarding approval and balloting. Thanks for raising the issue. We need more discussions on this but the EMG should know what we are considering.

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-----Original Message-----
From: Jones, Donald [mailto:Don.Jones@texasre.org]
Sent: Monday, February 06, 2012 11:00 AM
To: rsg
Subject: RE: Points to report to the EMG on EI

Colleagues:

Upon reflection, I wonder if anything really needs to be done regarding formation of an EI standards process. Any standard (or variance) that is directed at the entire EI is really just a CW standard with regional differences for WECC and TRE. Shouldn't such a project just go through the regular NERC Standards Process, rather than inventing a new process? Furthermore, most standards that would be appropriate for the EI would also be appropriate to consider for TRE and WECC, too, perhaps with different criteria specified for each Interconnection. We are all more sensitive now to the need for Region/Interconnection differences in some CW standards.

Thanks.

Don Jones
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-----Original Message-----
From: Guy V. Zito [mailto:gzito@npcc.org]
Sent: Friday, February 03, 2012 3:35 PM

To: rsg
Subject: Points to report to the EMG on EI
Importance: High

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From: Jones, Donald
To: rsg
Subject: RE: Points to report to the EMG on EI
Date: Friday, February 03, 2012 4:49:21 PM

FYI, the TRE Regional Standard/Variance process looks a lot like the old NERC Standard Development Process.

It looks to me like a key issue will be who has to/gets to approve an EI-wide standard. Will every EI Region's board have to sign off on it before it goes to NERC? Also, how will an industry ballot be weighted? Does each Region's membership need to approve a new variance, or just the EI as a whole? (I.e., what if NPCC votes no, but everyone else votes yes?) Will there need to be an EI-wide central authority created to provide oversight of an EI process?

(Sorry I missed the discussion today.)

-----Original Message-----
From: Guy V. Zito [mailto:gzito@npcc.org]
Sent: Friday, February 03, 2012 3:35 PM
To: rsg
Subject: Points to report to the EMG on EI
Importance: High

Will et all,

Based on the call today and my suggestion, I think the EMG should receive a status report at their next meeting that includes the following at a minimum, (RSG feel free to comment).

*
RSG EI members are currently reviewing the status of in-process Regional Standards and Variances
*
RSG will be engaged in developing an EI Variance process for consideration by the Standards Committee Process Subcommitte with the goal of eventual inclusion into the NERC Standards Development Process.
*
RSG will formally review all new regional standards and variances within those Regions in the EI for potential to move them forward as either coordinated EI efforts looking for opportunities to move them forward or continent wide standards (CWS).
*
RSG will actively review the developing new proposals for CWS standards and provide input to more effectively promote the development of EI standards and variances, providing an alternative to regional standards if warranted.
*
RSC EI group is reviewing the regions arranged on an "Interconnection Wide" basis, i.e. TRE and WECC to look for efficiencies in developing interconnection wide standards and if there are any other lessons to be learned in developing variances and how to advance the efficiencies of those processes and how they may utilized and developed into an EI process.
*
RSC EI is also currently identifying potential difficulties and obstacles to EI variances and standards in order to understand what process issues may exist and how these may be addressed.
*
RSC EI also will develop a review process for NERC CWS standard being developed to ensure that any shortfalls or inadequacies will be addressed during the drafting of those standards to ensure potential regional and interconnection differences are identified early in the development process and communicated to the NERC standard drafting team SDT.

As was stated on the call, I think we need to chart out a course to address the concerns we are aware of. Peter H. will be at the EMG meeting and if there is some discussion around the EI status report and

the expectation of deliverables of this group, then he will inquire as to further detail and a expectations for due date for completion. I think once we have affirmation of the above, a schedule for completion and project management will be possible. I think we should come to consensus on what is in the status report provided by Will. Comments welcome.

Thanks,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor New York, NY 10018
212-840-1070
212-302-2782 fax

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Standards Committee Meeting

December 7, 2011 | 8 a.m.-noon Eastern

Ritz-Carlton, Buckhead
3434 Peachtree Rd NE
Atlanta, GA 30326

Phone Number: 1-866-740-1260
Meeting Code: 4685998
Security Code: 224466

Introductions and Chair's Remarks

NERC Antitrust Compliance Guidelines and Public Announcement*

Agenda

1. **Review of Agenda (Approve)**

   Ben Li chaired (Allen present by phone)

   No conference call tomorrow.

2. **Waiver of 5-day Rule (Approve)**

3. **Consent Agenda (Approve)**

   a. November 10, 2011 Standards Committee Meeting Minutes* **(Ratify)**

   ~~a.~~b. Project 2010-07 — Generator Requirements at the Transmission Interface Standard Drafting Team * **(Appoint)** **Confidential (To be sent separately)**

   Approved

4. **High Priority Projects, Activities, and Action Items (Review)**

   a. Status of Projects Identified as High Priority* (A. Rodriquez)

Eight Projects Behind Schedule

Analysis of timelines and delays are based on schedules adjusted and presented at the July SC meeting. It should be recognized that resource and posting conflicts may delay these projects further; Standards is developing process enhancements to manage these conflicts more aggressively in 2012.

1. *Project 2007-06 System Protection Coordination. This project is approximately 1 month behind schedule (new from last report). The SDT is still finalizing its first draft of the new standard, and is expecting to deliver it for quality review in mid-December.*
2. *Project 2006-06 Reliability Coordination. This project is approximately 4 months behind schedule (an additional month of delay added from last report). Its schedule has slipped this additional month due to more time than expected being required to address to quality concerns and assemble documents for posting, but the team anticipates completing this task the week of November 28th. Additionally, the project is somewhat linked with project 2007-02, and posting for 2006-06 is being coordinated with the posting of that project.*
3. *Project 2007-02 Operating Personnel Communication Protocols. This project is approximately 5 months behind schedule (an additional month of delay added from last report). The additional delay has been caused by the team focusing its efforts on moving the 2009-22 Interpretation forward. It is anticipated that the completion of 2009-22 will eliminate any further slippage.*
4. *Project 2007-03: Real-time Operations - This project is approximately 1 month behind schedule (no change from last report).*
5. *Project 2007-07 Vegetation Management. This project has been approved by the Board of Trustees, and is being prepared for filing with the FERC. Its delays were caused first by its coordinator leaving NERC, then primarily by moving to informal development, both periods during which the SDT worked independently. This resulted in work taking a significantly longer amount of time than planned (slightly more than one year in total from the Initial ballot to the submission for Recirculation). It is expected that this will be filed with the Commission before the end of the year.*
6. *Project 2007-09 Generator Verification. This project is approximately 2 months behind schedule (an additional half- month of delay added from last report). Recently, its schedule has slipped due to more time being required than expected to respond to industry comments and assemble documents for the next posting. At this point, all documents have been assembled and submitted for Quality Review, and some Quality Reviews have already been completed.*
7. *Project 2009-01 Disturbance and Sabotage Reporting. This project is approximately 2.5 months behind schedule (no change from last report).*
8. *Project 2010-05.1 Phase 1 of Protection Systems: Misoperations. This project is approximately 8 months behind the desired schedule (an additional half-month of delay added from last report). This is due largely to confusion regarding the projects goals. At the time of this writing, the Advisor is still discussing with the team how they will respond to the SC's request for an accelerated project schedule.*

   Discussion: Ask the DT leadership to report instead of staff.

b. Project 2008-06 — Cyber Security — Order 706 – Request to Extend Ballot and Comment Period *

   John Seelke asked the Standards Committee to consider extending the comment period for Project 2008-06 – Cyber Security – Order 706 from 60 days to 90 days.

Not supported by staff.

365 pages of material, it's massive.

Not approved. Item closed.

Discussion on v4 vs. v5 implementation plan; conflict between proposed plan and FERC filings.

Staff will contact DT to fix.

c. Project 2010-07 – Generator Requirements at the Transmission Interface – Impact of Compliance Process Directive #2011-CAG-001* (P. Brown)

Compliance Directive #2011-CAG-001 Regarding Generator Transmission Leads was recently posted for stakeholder comment. During the November, 2011 Standards Committee meeting the following concerns with this draft directive were raised, and further discussion was deferred to the December 2011 Standards Committee meeting:

- *The directive seems to circumvent the Standard Processes Manual by advancing the implementation of the standards currently under development within Project 2010-07.*
- *The directive adds standards to the GOTO project beyond those identified by the GOTO team*
- *The directive expands the definitions of Transmission Operator and Transmission Owner as defined in the Compliance Registry, an appendix in the Rules of Procedure. Modifications to the Rules of Procedure should be made following the approved process.*

Patrick Brown led a discussion on the draft directive and standards-related issues associated with compliance directives. The essence of the discussion may be carried forward to the joint meeting of the Standards Committee and Compliance and Certification Committee during the afternoon of December 7, 2011.

Asking that the SC writes a report to the CCC reporting the potential violation of the development process.

Maureen: Staff sees the Directive as an interim solution and not in conflict with the project and/or the process.

Ben: language in the directive assumes prematurely the outcome of the project. Industry were not asked for comments (only trade associations were).

Proposal to wait for the final version of the directive and act when that happens.

d. Status of Outstanding Interpretations *(L. Hussey and A. Rodriquez)

No new requests received in the last month.

5. **Actions**

a. Revised Project Schedules

- Project 2010-05.1 Phase 1 of Protection Systems: Misoperations – Project schedule* **(Endorse)**
- Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves – Project Schedule* **(Endorse)**

Project 2010-05.1 Phase 1 of Protection Systems: Misoperations

Background: *During the October 2011 Standards Committee meeting, the Standards Committee reviewed the proposed schedule for Project 2010-05.1 Phase 1 of Protection Systems: Misoperations and expressed concern that the project's duration appears to extend longer than expected and doesn't reflect the "high priority" placed on this project.*

Ron Parsons volunteered to participate in the next conference call meeting of this team to share the Standards Committee's concerns and determine if there is a good reason to adopt the proposed schedule rather than a schedule that would produce a standard in a shorter period of time and to identify why the team wasn't able to use the original work product.

Ron reported:

Lessons learned; (a) need more carryover from rapid development team to the drafting team. (b) need a clean handoff from rapid team to SDT. (c) need for improved communications to SDTs to clarify expectations. (d) offer SDTs members the opportunity to to express concerns to the SC.

SDT has no problem with the concept but the issue is implementation of the project.

The drafting team has developed a revised schedule with key milestones as follows:

- *Complete response to comments and revised draft standard (from comment period ending July 11, 2011) by March 12, 2012*
- *Post revised standard for parallel comment and initial ballot April 20, 2012*
- *Post revised standard for recirculation ballot July 20, 2012*

There are no hard dates to be met in this project.

Request: Endorse revised schedule.

Approved.

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves

Background: During the October 2011 Standards Committee meeting, the Standards Committee

reviewed the proposed schedule for Project 2010-14.1 Phase 1 of Balancing Authority reliability based Controls: Reserves and endorsed the schedule for delivery of the standards that had already undergone considerable industry vetting, but directed the team to propose a separate schedule for the standard on reserves that includes at least one successive ballot.

The drafting team has developed a revised schedule with key milestones as follows:

- *Post for 30 days starting December 23, 2011 – January 22, 2012*
- *Post revised standard for parallel comment and initial ballot May 1, 2012*
- *Post revised standard for parallel comment and successive ballot August 28, 2012*
- *Post revised standard for recirculation ballot December 11, 2012*

Request: Endorse revised schedule.

Note: As part of ongoing efforts to improve project management, a new set of schedules will be presented to the Standards Committee next year for approval and base lining. These schedules will use new templates and be adjusted to address resource conflicts. As such, the expected delivery dates will change. Deviations will be minor +/- 2 weeks.

Approved

b. Project 2010-07 – Generator Requirements at the Transmission Interface Drafting Team – Solicit Additional Member* **(Approve)**

The GOTO SDT wants to add an additional drafting team member. The team would like to post a vacancy for a NERC-certified System Operator (preferably for a Transmission Operator or Reliability Coordinator function). The candidate should also be familiar with the history of the GOTO Ad Hoc Group, recent registration activity, and the work of the Project 2010-07 SDT.

***Request:** Authorize soliciting another drafting team member who is a NERC-certified System Operator (preferably for a Transmission Operator or Reliability Coordinator function) familiar with the history of the GOTO Ad Hoc Group, recent registration activity, and the work of the Project 2010-07 SDT.*

Approved

c. Project 2010-17 – Definition of Bulk Electric System – Post documents for Phase 2 **(To be sent separately)** **(Approve)**

Still working in SAR. Executive committee will see final SAR.

6. **Reports (Discuss)**

a. Report from November 29, 2011 FERC Conference (A. Mosher)

Good discussion.

7. **Coordination (Review)**
   a. Coordination with Regulatory and Governmental Authorities (H. Hawkins)

   Aggressive schedule ahead with recent votes and NOPRs comments.

8. **Discussion Items (Discuss)**
   a. Interim Standards Committee Election Results *

Segment 1-2012-13	*Not determined yet*	*Run-off election*
Segment 1-2011-12	*Jason Shaver (ATC)*	
Segment 2-2011-12	*Patrick Brown (PJM)*	
Segment 2-2012-13	*Ben Li (IESO)*	
Segment 3-2011-12	*Ron Parsons (Alabama Power Co.)*	
Segment 3-2012-13	*John Bussman (Associated Electric Cooperative Inc.)*	
Segment 4-2011-12	*Joseph Tarantino (Sacramento Municipal Utility District)*	
Segment 4-2012-13	*Allen Mosher (American Public Power Association)*	
Segment 5-2012-13	*Not determined yet*	*Run-off election*
Segment 5-2011-12	*Mike Gildea (Dominion)*	
Segment 6-2011-12	*Silvia Parada Mitchell (NextEra Energy, Inc.)*	
Segment 6-2012-13	*Alice Murdock Ireland (Xcel Energy, Inc.)*	
Segment 7-2011-12	*John Anderson (ELCON)*	
Segment 7-2012-13	*Frank McElvain (Siemens Energy, Inc.)*	
Segment 8-2011-12	*Michael Goggin (American Wind Energy*	

	Association)	
Segment 8-2012-13	*Frederick Plett (Massachusetts Attorney General)*	
Segment 9-2011-12	*Diane Barney (New York State Public Service Commission)*	
Segment 9-2012-13	*Klaus Lambeck (Public Utilities Commission of Ohio)*	
Segment 10-2011-12	*Steve Rueckert (WECC)*	
Segment 10-2012-13	*Linda Campbell (FRCC)*	
Canada	*Not determined yet*	*Depends on result of Segment 1 run-off election*

FERC approved the changes to procedure effective immediately.

Nominations requests sent for chair and vice-chair.

Opens vacancy for Canadian position.

b. Five Year Review of Effective Standards *

As per the Manual, if it's the 5 year review, SC to appoint a review team to determine whether the standard needs any work. Review of team to be posted for 45-day comment period. If reaffirmed, the standard will remain in effect until the next 5-year review or otherwise modified before that time by a different action.

Discussion:

Does the process need to be revised to include some kind of prioritization?

Ask Legal to review

Ask ANSI for assistance in helping move to a maintenance cycle.

Look at layering standards so that the meaningful standards are reviewed more frequently than others.

c. Planning for January Standards Committee Meeting *

January 11-12.

SCPS meeting full day.

QR training will be done later.

Topics for the SC:

SC 2012 goals and aligning of goals with ERO goals.

Strategies to develop standards more efficiently

ANSI accreditation

Refreshing the RBB.

SCPS topics: Process for: Send suggestion to Laura by January 3rd.

9. **Informational Items (Review)**

   a. Drafting Team Vacancies*

Project 2007-06 System Protection Coordination	Seeking an individual from a Canadian entity.	Experience in coordination of Protection Systems (new installations and revisions).
Project 2007-12 Frequency Response	Seeking individual representing Transmission Dependent Utilities (TDU).	Experience in analyzing or modeling frequency response.
Project 2010-07: Generator Requirements at the Transmission Interface	Seeking an individual who is currently a NERC-certified System Operator, preferably as a Transmission Operator or Reliability Coordinator. The candidate should also be familiar with the history of the GOTO Ad Hoc Group, recent registration activity, and the work of the Project 2010-07 SDT.	

   b. Standards Committee Roster*

10. **Executive Committee Actions (Pre-authorize)**

   a. Project 2010-17 – Definition of Bulk Electric System – Post documents for Phase II **(Approve)**

   Approved

11. **Adjourn**

*Background materials included.

Joint CCC/SC Meeting

Wednesday, December 7, 2011 | 1:00 p.m. – 5:00 p.m. EST
Dial-In: 1.866.740.1260
Passcode: 6515232
Security Code: 120711

Introductions and Chair's Remarks
NERC Antitrust Compliance Guidelines and Public Announcement
Agenda

1. **Communication Between Standards & Compliance**

   a. Overview of CCC roles and how they interface with NERC * (Terry Bilke)

   Program Responsibilities

- *Advise NERC and the NERC BOT on: NERC Compliance Monitoring and Enforcement Program (CMEP)*
- *Organization Registration Program (Registration Program)*
- *Organization Certification Program (Certification Program)*
- *Responsibilities include: Monitoring conformance to NERC's Rules of Procedure on the items programs above*
- *Recommending changes to the Rules of Procedure on these programs*

Other responsibilities:

- *Monitoring Compliance to Reliability Standards applicable to NERC*
- *NERC's adherence to standards development process*
- *Monitoring approach oIndependent contractor (preferred) or CCC-led audits*
- *Self-Certifications*
- *Self-Report (preferred)*
- *Spot Checks*
- *Hearing body for appeals where NERC is the Compliance Monitor or where NERC is administering the compliance action*
- *Provide pool of individuals for development of compliance elements to the Standards and to perform Quality Reviews of compliance aspects of Standards*
- *Participates in audits of Regional Entities' compliance programs*
- *Provides comments to NERC with respect to stakeholders' perception of the policies, practices and effectiveness of the Compliance Program, Registration Program, and Certification Program*
- *Provides assistance to NERC and the Regional Entities on implementation of the Compliance and Organization Registration and Certification Programs*
- *Other duties as assigned by the NERC Board of Trustees*

b. Overview of SC roles and how they interface with NERC * (Ben Li)

1. *Manage Standards Development*
2. *Manage Standards Process*
3. *Review Effectiveness of Balloting Process*
4. *Coordinate with Compliance*
5. *Coordinate with NAESB*
6. *Coordinate with Board of Trustees, Regulators and Industry Groups, and Stakeholders*

Manage Standards Development

- *Authorize posting (SARs)*
- *Approve development of new/revised standards based on SARs*
- *Determine whether to field test a proposed standard*
- *Facilitate industry discussion of proposed standards*
- *Provide guidance to drafting teams*
- *Appoint standard drafting teams*
- *Monitor & manages progress/prioritization of standards projects*
- *Ensure integrity of the standards process*
- *Ensure standards meet quality attributes*
- *Monitor effectiveness of standard process & implement improvements*
- *Ensure standard process maintains ANSI accreditation*
- *Develop & maintain annual & long-term plans consistent with ERO's strategic plans*
- *Manage update of reference documents*
- *Review registered ballot body membership for balance*
- *Review balloting results for balance*
- *Monitor participation in the balloting process*

Coordination with compliance

- *Work with CCC through activities such as Quality Reviews*
- *Ensure drafting teams are coordinating with/receiving support from the compliance program*
- *Ensure applicability section of standards is clear and meets needs of compliance program*
- *Ensure implementation plans meet the needs of compliance program*

Coordination with NAESB

- *Executive Committee assists Director of Standards in implementing the NERC/NAESB Joint Coordination Procedure*
- *Executive Committee develops annual work plan for joint activities with NAESB*

Coordinate with others:

- *Coordinate with NERC Board of Trustees, Regulators and Industry Groups, and Stakeholders Interface with NERC & industry groups regarding standards*
- *Actively seek inputs from the BOT, regulators, Regions, compliance program, readiness audit program, technical committees, & stakeholders on standards issues*
- *Sponsor standards conferences to communicate with stakeholders*
- *Review standards work plans & key projects with regulators*

c. Compliance information available for Standard Drafting Teams * (Ryan Stewart)

Data Fields:

- *Standard*
- *Violation Description and Cause*
- *Potential Impact to Bulk Power System Statement*
- *Registered Functions*
- *Region*
- *Method of Discovery*
- *Date Regional Entity Discovered Violation*
- *Dismissal Rate (% of Total)*

Future involvement

- *What areas of Compliance do Standards feel would be valuable?*

2. **Joint Activities**

a. Status of VRF & VSL proposals * (Andy Rodriquez)

VRF definitions and tools

- *VRF Guidelines*

  Goal – Increase clarity of NERC's VRF definitions

  Encountered hurdles to providing improved clarity Guideline definitions can not be written to reflect the tool

  Current definitions are 2 dimensional (Consequence & Severity)

  Issue is 3 dimensional (Consequence, Severity & Probability)

  Need more diverse input from industry (buy-in)
- *VRF Tool Goal – Standardize the assessment process for SDTs*

  Encountered hurdles to making a valid assessment Mixes a qualitative problem with a quantitative method

  2 dimensional, not 3 dimensional (Contingency & Probability)

  Better to have sound definitions and build the tool, not vice-versa

VRF Next Steps:

- *Need to hold in-person development meetings January & February 2012*

  SME Focus areas (CIP, Planning, Operations, & Protection)

  Treat effort like a SDT for transparency
- *Options for SC action Suggest participants to work in definition development, or*

  Endorse NERC to seek volunteers
- *Post for industry comment March 2012*

  Revise based on comments and prepare report
- *SC meeting April 2012*

  Consider next steps

VSL Pro forma:

- *Goal – Simplify VSL development Reduce development time*

  Eliminate flaws and errors
- *Proposal Introduces the use of a Standard's Purpose statement to assist in determining compliance oNeed to work out issues regarding Purpose statements*

  Conformity with FERC directives
- *Needs: Need more diverse input from industry (buy-in)*

VSL Next Steps:

- *Need to hold in-person development meetings January & February 2012*

  Utilize the VRF team (emphasis on a compliance member)

  Treat effort like a SDT for transparency
- *Options for SC action Suggest participants to work in Pro Forma development, or*

  Endorse NERC to seek volunteers

  Post for industry comment March 2012 Revise based on comments and prepare report
- *SC meeting April 2012 Consider next steps*

Discussion:

Volunteers from SC and CCC:

Concept documents need polishing

Modify definition to fit tool better. Bring back to SC and CCC

Ready for full industry stakeholders? BoT?

Get representation from Res to assist developing final products

Abort projects of VRFs and VSLs are not needed with a revised process. Need a transition plan

FERC staff open to concept of retiring VRFs and VSLs.

b. RSAW development and opportunity for drafting team input * (Linda Campbell)

- *Involve drafting team in development of technical content of RSAWS Identify what acceptable performance looks like.*

Identify what unacceptable performance looks like – and why

- *When to draft RSAWS?*

  As part of standard development, or

  Following standard approval

  Develop together with the standars, not after the standard has been approved.

- *Should RSAWs replace Measures?*

RSAWs are a good way of keeping compliance records.

Consideration if replacing Measures with RSAWs: Measures are balloted – will RSAWs be balloted?

If replaced, are they enforceable in Canada? In Canada, only the standards are enforceable.

Proposal: SC-CCC to present to MRC-BoT in Feb. (or later?) for endorsement (policy issue).

Two step action:

1. *Linda Campbell to work with Mike Mon/Val to determine how to involve the SDT in the RSAW development.*
2. *As experience gained, ideas may be generated at replacing Measures with RSAWs.*

c. Participation in quality reviews * (Patrick Brown)

Overview:

- *Conducted before each posting for formal comment/ballot*
- *Drafting team sends documents to standards staff*
- *Standards staff solicits 3 QR reviewers (compliance, legal, standards)*
- *QR members review documents in parallel, then have conference call to develop consensus document*
- *Results sent to Drafting Team*
- *Drafting Team's response sent to QRAWG for review*
- *QRAWG determines if standard is ready to post*

Current status:

- *More than 50 people trained to conduct QRs, including 7 CCC members – next session December 9*
- *Training expanded to include auditors, Regional staff developing/reviewing standards, stakeholder lawyers working in standards/compliance*
- *Conducted 48 reviews from Jan 1-Nov 30 2011 (5 in progress)*
- *Some teams more receptive to feedback than others*

Ideas for QR Guidelines:

- *Limit focus on standard – not other documents (mapping document, issues, VRF/VSL justification, implementation plan)*
- *Use same review team throughout project cycle*
- *Limit focus in successive reviews to just changed content*
- *Establish criteria for representing Compliance perspective and for representing Legal perspective*

Discussion:

QR teams should have a certain level of technical expertise.

d. CANs Process and SC/CCC involvement * (Valerie Agnew)

Timing:

- *Ideally, input for both the prioritization of potential CANS and input on the issues would be provided while the CAN is on the potential CAN list, prior to development*
- *Input on the issue could be received at anytime up to the close of the industry comment period*

Prioritization:

- *Provide on a regular basis as determined by each committee*

May provide jointly or as separate committees

- *Group potential CAN topics as a high, medium or low priority*

May specify within each category

May specify CAN topic should not be produced

CAN Input:

- *Substantive issue input*

Ideally, committees would provide input as potential CANs are added to list, prior to CAN being developed

- *Provide insights into issue*
- *Provide input into compliance application*

Discussion:

CCC SIS agreed to participate in prioritization

Consider phasing the prioritization so that it is timely

SC can provide input. In addition:

i. continue to recommend a single portal for input to questions about standards

ii. Consider CAN as alternate to a formal interpretation where acceptable to requester; also possible to address through rapid revision

iii. Concerns about substantive input to CANs and resultant impact (enforcement)

As CANs are received, consider assigning to one option as a preference, recognizing more than one may be necessary under some circumstances:

CAN, interpretation, rapid development

With single portal, there is no need for prioritization of CANs.

For backlog of CANs – consider allowing SIS do initial ranking, then send to SC for review/input.

What information would be available to the SC to clarify the issue in the CAN?

Do the SC members have the technical knowledge for this role?

CANs in queue:

CAN-0019	*CIP-007-3 R3 Security Patches*

CAN-0023	*CIP-005 R3, CIP-006 R6, CIP-007 R6 – Loggin System Failures*
CAN-0032	*EOP-008 – Above and Beyond*
CAN-0034	*EOP-002-2.1 R1, IRO-001-1.1 R3, TOP-001-1 R1 Authority Letters*
CAN-0035	*Periodic Data Submittals*
CAN-0037	*Roll-up Violations*
CAN-0038	*PER-002 R4 Training Hours*
CAN-0041	*IRO-004 R1 FERC Discrepancy - Complete Dynamic Modeling*
CAN-0033	*PRC-023 R1.1; R1.6; R1.7; R1.8 and R1.9 Load Questions*
CAN-0036	*PRC-023 - applicability to Generator Owners that are not also transmission owners and/or distribution providers as stated in FERC Order 733*
CAN-0044	*TOP-001 R1, R2, R5 and R8* *FERC Discrepancy - System Emergency and emergency conditions*

e. Certification and Standards * (Valerie Agnew)

Staff recommends retiring lower level "facilitating" requirements that are addressed through higher level performance-based requirements, especially in cases where the evidence retention is onerous.

Certification only uses VRF matrix as a basis for capabilities. Certification is a capabilities issue, compliance is audit issue.

Consider consent of re-verification of capabilities.

f. Status of Adequate Level of Reliability Task Force * (Allen Mosher)

- *Adequate Level of Reliability Task Force (ALRTF) charged with:*

  Reviewing current definition of ALRTF (filed for information with FERC in 2008)

  Determining if existing definition and characteristics need enhancement in coordination with the MRC's BES/ALR Policy Group
- *Task Force includes representatives from each of the Standing Committees*
- *Has met monthly since June 2011 but still at ground level.*

  Goal:
- *Definition of ALR that encompasses NERC's responsibility to ensure reliability, and to define objectives and characteristics that are measurable*

  Enable the ERO enterprise to focus on and align its activities with specific characteristics of ALR that have the greatest impact on bulk power system reliability
- *Definition must be:*

  Concise, yet self-contained

  Self-explanatory to BES planners and operators

  Meaningful to policymakers – placing a premium on translation in the ALRTF Report

- *Input from MRC's BES/ALR Policy Group directed group to consider:*

  Cost/benefit

  Load loss distinctions

  Definition of cascading

Draft Definition:

Seven Reliability Objectives

- *Associated Performance Outcomes Addressed in four time frames*
- *Associated Disturbances/Initiating Events*

"Collectively, the performance outcome and the associated disturbances/initiating events fully describe the characteristics of each reliability objective – what it is and under what conditions we intend to achieve the reliability objective."

Reliability Objectives:

1. *Prevent the BES from instability, uncontrolled separation, cascading, and voltage collapse when subject to a set of predefined initiating events.*
2. *Maintain BES frequency within defined parameters under normal operating conditions and when subject to a set of predefined initiating events.*
3. *Maintain BES voltage within defined parameters during normal operating conditions and when subject to a set of predefined initiating events.*
4. *Provide and maintain sufficient transfer capability of the BES transmission system to meet required BES demands during normal operating conditions and when subject to a set of predefined initiating events.*
5. *Provide and maintain sufficient resource capability on the BES to meet required BES demands during normal operating conditions and when subject to a set of predefined initiating events. Means assess not necessarily to build/operate as mandate to build is not necessarily within the FM responsibility (depends on jurisdiction).*
6. *Minimize adverse impact on the BES resulting from conditions beyond the scope of the set of predefined initiating events (e.g., multiple contingencies or unplanned, uncontrolled outages).*
7. *Recover from blackouts and widespread outages with the ability to restore BES Facilities in a controlled manner that rebuilds BES integrity and restores supply to load.*

Next Steps:

- *Dec. 7, 2011: Present to SC/CCC*
- *Dec. 13-15, 2011: Q&A (if necessary) during OC, PC, CIPC meetings*
- *Jan. 18-19, 2012: Next ALRTF meeting*
- *End of Jan.: Complete robust draft definition and technical document*
- *Feb. 2012: Present draft documents to SCCG for review*
- *March 2012: Post for industry comment*

3. **Future Activities**

4. **Adjourn**

Standards Committee Nomination Form

Open December 13, 2011 – January 4, 2012

Representing Segment 2 and Segment 4

New Nomination Period for SC Members to Represent Segment 2 and Segment 4 Open:

A nomination period to identify candidates to fill the two-year terms left vacant through the election of officers is open through Wednesday, January 4, 2012. (Under the Standards Committee Charter, the Standards Committee officers are non-voting members of the Standards Committee. By filling the two-year terms left vacant through the election of officers, all Industry Segments will be represented by two voting members.)

Registered Ballot Body members and others interested in NERC Reliability Standards are encouraged to submit nominations for individuals to fill the two SC vacant positions. With reliability standards mandatory for all bulk power system owners, operators, and users in North America, the SC's oversight role is increasingly important. The SC consists of two members from each of the ten Industry Segments that make up the Registered Ballot Body, with at least two members representing Canada. The SC is elected by stakeholders, and reports directly to the Board of Trustees. The SC meets monthly, either by conference call or in face-to-face meetings. Members who cannot travel to the meetings may participate by conference call. The SC Charter provides a description of the SC's responsibilities.

The SC reports to the NERC Board of Trustees and oversees the development of NERC Reliability Standards by performing the following tasks governed by the Standard Processes Manual and the Standards Committee Charter:

- Manages standard development
- Manages the standards process
- Reviews the effectiveness of the balloting process
- Coordinates with the compliance program
- Coordinates with NAESB
- Coordinates with the NERC Board of Trustees, regulators and industry groups, and stakeholders

Any person may nominate any other person to serve on the SC, with the limitation that the nominee must be employed by or an agent of an entity that is registered in that segment of the Registered Ballot Body. The nominee is not required to be the RBB representative from that organization.

Nominations will be accepted for the positions listed below. You may use this form to nominate candidates for any of the nine segments that use the default SC election procedure. You may submit

more than one nomination. Please, however, use one form per nomination. You are welcome to nominate yourself.

Which Industry Segment will this candidate represent? (Check one.)		
☐	Segment 2	Regional Transmission Organizations and Independent System Operators
☐	Segment 4	Transmission-dependent Utilities

Nominee's name and contact information.	
Name	
Job Title	
Organization	
Telephone	
E-mail	
Mailing Address	

Has the nominee been contacted to verify willingness to serve on the SC?	Yes ☐	No ☐

Person making this nomination (if different from nominee).	
Name	
Organization	
Telephone	
E-mail	

Please provide a brief summary of the nominee's qualifications for this SC position. (The summary should be no longer than a single page of single-spaced text.

Please complete this form no later than January 4, 2012 and send to Monica Benson at monica.benson@nerc.net.

From: Monica Benson
To: monica.benson@nerc.net
Subject: Standards Committee - Ballot Election Results | Nomination Period for Segment 2 and Segment 4 Re-Opened
Date: Tuesday, December 13, 2011 4:16:01 PM
Attachments: SC_Election_Form_2012-2013_seg_2_4_121311.doc

Standards Committee
Ballot Election Results

Nomination Period for Segment 2 (ISOs and RTOs) and Segment 4 (Transmission Dependent Utilities) Re-Opened

Standards Committee Industry Segment Ballot Results:
The second ballot (runoff ballot) for the election of Standards Committee (SC) members in Industry Segments 1 and 5 for the two-year term January 1, 2012 through December 31, 2013, and the election of officers for the two year term January 1, 2012 through December 31, 2013 both ended on Friday, December 9.

Industry Segment Election Criteria:
In the second ballot, the candidate receiving the highest number of votes is elected to represent that Segment. The results are shown below:

- ***Segment 1*** — Carol Sedewitz, National Grid
- ***Segment 5*** — Scott Miller, MEAG Power

Canadian Representative:
The SC Election Procedure has a special provision to ensure there is sufficient Canadian representation on the SC. If any regular election of SC members does not result in at least two Canadian members being elected, the Canadian nominees receiving the next highest percentage of votes within their respective Segment(s) will be designated as members, as needed to achieve a total of two Canadian members.
The regular election did not result in the election of two Canadian members. Thus the following individual who was nominated and received the second highest percentage of votes within Segment 1 has been elected for a one-year term to represent Canada:

- ***Canada*** — David Kiguel, Hydro One Networks Inc.

Election of Officers:
A nomination period for the election of officers has ended. Allen Mosher, Segment 4 representative, was the sole nominee to serve as chair; Ben Li, Segment 2 representative, was the sole nominee to serve as vice chair. Since Allen and Ben were nominated unopposed, they are elected.

- ***Chair*** – Allen Mosher, American Public Power Association
- ***Vice Chair*** – Ben Li, Independent Electric System Operator

Allen and Ben were previously elected by their industry segment members to serve a two-year term January 1, 2012 through December 31, 2013 and it is now necessary to find candidates to fill these positions left vacant through the election of officers.

New Nomination Period for SC Members to Represent Segment 2 and Segment 4 Open:

A nomination period to identify candidates to fill the two-year terms left vacant through the election of officers is open through Wednesday, January 4, 2012. (Under the SC Charter, the SC officers are non-voting members of the SC. By filling the two-year terms left vacant through the election of officers, all Industry Segments will be represented by two voting members.) Registered Ballot Body members and others interested in NERC Reliability Standards are encouraged to submit nominations for individuals to fill the two SC vacant positions. With reliability standards mandatory for all bulk power system owners, operators, and users in North America, the SC's oversight role is increasingly important. The SC consists of two members from each of the ten Industry Segments that make up the Registered Ballot Body, with at least two members representing Canada. The SC is elected by stakeholders, and reports directly to the Board of Trustees. The SC meets monthly, either by conference call or in face-to-face meetings. Members who cannot travel to the meetings may participate by conference call. The SC Charter provides a description of the SC's responsibilities.

A nomination form is attached to this email for convenience and has also been posted on the NERC website. Please submit completed SC nomination forms to monica.benson@nerc.net no later than **January 4, 2012**. An election of segment representatives will be conducted immediately after the nominations period is closed.

Next Steps:
Following the nomination period, an election will be held to fill the vacant positions in Segments 2 and Segment 4. Questions may be addressed to Monica Benson or 404-446-2573.

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 Committee Election Announcement - Nomination Period for Segments 2 and 4 Now Closed
Date: Friday, January 06, 2012 10:34:24 AM

Standards Committee Election Announcement

Nomination Period for Segments 2 and 4 Now Closed

A nomination period to identify candidates to fill the two Standards Committee positions left vacant in Segment 2 and Segment 4 through the election of Standards Committee officers has closed.

Nomination Results:

Segment 2:

There was one nominee, H. Steven Myers from ERCOT, to fill the vacancy in Segment 2. Since Mr. Myers was nominated unopposed, he is elected.

Segment 4:

There were two nominees to fill the vacancy in Segment 4, Frank Gaffney of Florida Municipal Power Authority and Keith Porterfield of Georgia System Operations Corporation. An election to determine who will represent Segment 4 will be held January 6-17, 2012. Only Registered Ballot Body members in Segment 4, or their proxies, are eligible to vote in the Segment 4 special election and they will be sent instructions on how to ballot.

Next Steps to Fill Standards Committee Vacancy in Segment 4:

The election to fill the vacancy in Segment 4 will begin on Friday, January 6, 2012 and remain open through 8 p.m. on Tuesday, January 17, 2012. With only two candidates to fill the vacancy in Segment 4, the candidate receiving the highest number of votes will be elected.

Next Steps

The final results of the election will be announced. Questions may be addressed to Monica Benson at monica.benson@nerc.net or by calling 404-446-2573.

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

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From:	Gerard J. Dunbar
To:	Guy V. Zito
Cc:	Lee R. Pedowicz
Subject:	Meeting Notes.....SCPS.....SC.....RSG.....January 10, January 11, January 12
Date:	Thursday, January 12, 2012 8:44:44 PM

Tuesday January 10, 2012 ……Standards Committee Process Subcommittee (SCPS):

Administrative:

- Jason Shaver and Pat Brown leaving SCPS.

Agenda Item 1a:

- Process for use of Drafting Teams to assist in developing RSAWs (Audit Worksheets):

  A small group will be formed comprised of Standards Staff and Compliance Staff to develop an approach that would ultimately be presented to the SC.

  The SCPS discussed this item in the context of the possibility of eventually eliminating Measures from the Standards…..the idea being that if the RSAW is precisely written a Measure will not be required.

Agenda Item 1b:

- Process for replacing an appointed drafting team member:

  David Kiguel led the discussion.

  The SCPS made some changes to the draft document…….significantly they removed the questionnaire and revised language in the guidelines……they agreed to leave the obstruction issue but moved it.

Agenda Item 1c:

- Rapid Revision process…….the SCPS discussed proposing a **single portal concept**…….where NERC will triage a request and decide whether a request is resolved as either a CAN, an Interpretation, Rapid Revision, or Standard Development.

Agenda Item 2a:

- Prioritizing CAN's:

  SCPS reviewed a tool developed by Linn Oelker for prioritizing CAN's ……very similar to tool developed to prioritize standard development…….only the criteria has been

changed……..will be introduced to the SC.

Agenda Item 2a:

- Proposal to eliminate the Quality Review Advisory Working Group (QRAWG)…..SCPS does not support eliminating……NERC staff will present the proposal to the SC….

  Next meeting ……Tampa April 10th……..Ben recommending a full day meeting since he was not able to get to all agenda items.

Wednesday January 11, 2012…..Standards Committee Day 1:

Note: See separate notes on Alternative Standard Development Procedure

Summary of high priority projects.

- BES on track to go the NERC BOT on 1/18…..and on schedule to be presented to FERC.

- 6 Projects on schedule.
  7 Projects behind schedule.

- Herb commented that NERC will occasionally hold back posting a standard if too many standards are posted at one time…..that can lead to a project falling behind…..Herb keeps Allan Mosier informed of these circumstances……NERC refers to these situations as 'posting constraints'.

- SC had a long discussion on PRC -005……..the importance of the standard and the number of violations (high)….Charles Rogers SDT chair called in……PRC -005 narrowly failed the recirc. ballot last summer and a new ballot pool was formed according to procedure…..significant drop in approval on initial ballot of new ballot pool seems to be related to the new ballot pool members…..Charles Rogers optimistic and expects a successful ballot….Allen Mosier recommending a Technical Conference …..Carol Sedewitz, suggested a regional Technical Conference…..

- Project 2007-12 Frequency response……SC endorsed revised schedule… ongoing concern over the BA being held responsible for frequency response if they don't own the asset…..

Update on outstanding Interpretations…….

- Interpretation on the definition of a 'single point of failure'……. submitted in Dec . 2011 for TPL 003 and TPL 004…Carol Sedewitz concern…….there is an existing NERC data request that is looking for information on the same issue……..concern over available resources to answer data request and develop the Request for Interpretation on this same issue…..also there is the potential for the issue to become tangled in the TPL standard which is

currently before FERC…..

Candidates for Rapid Revision…..

- SC had a lengthy discussion on two FMPP interpretatations of existing TOP standards …… existing body of TOP standards are currently being balloted…..FMPP concern is addressed in the current balloted standards…..concern though is that successive ballots and recirc. Ballot and NERC and FERC approvals and implementation plan could take a very long time….intent with the rapid revision is to make focused changes on the existing body of standards…interpretation of TOP002 is more involved and would not be a good candidate for a rapid revision……SC approved a motion for a rapid revision of TOP-006…

  Also another interpretation request for a VAR standard…….no team in place…but SC approved motion to move the VAR standard to a Rapid Revision process.

Mike Gildea asked for a discussion on the status of Results Based Standards…..

- Mike is concerned that it seems to no longer be a priority with NERC……Herb and Andy Rodriguez countered that despite the fact that no one is talking about them results based standards has been internalized at NERC and is still very much how they approach standard development…..FAC 003 Veg. Man. currently before FERC and the first NERC BOT approved results based standard will be the acid test since NERC will receive FERC comments on results based…..Herb agreed to post on the NERC website a list of those standards that are being developed as results based….

Jim Castle presented on behalf of the NAESB Business Practices Sub Committee

- Jim requested NERC to elevate the priority of Interchange Standard Development in order to support conforming changes in the NAESB business practice efforts……intra BA transactions need to be tagged… limited modifications for IRO-006-East -1…..

  NAESB can move ahead with the business practice…….Operating Reliability Subcommittee (ORS) needs to identify any reliability gaps…….no SC action at this time…

Ben Li reviewed the CAN priority tool…….(see SCPS notes on the CAN priority tool above.)

- SC approves this approach and will send to other standing committees (CCC)for their action.

SC heard NERC staff proposal to eliminate the Quality Review Advisory Working Group (QRAWG) …..

- QRAWG provides administrative oversight on behalf of the SC……NERC would like the SC Exec Comm. will now provide this oversight… extended discussion among the SC……many felt that the QRAWG provides value….

SC approved motion to eliminate QRAWG but assign staff to bring significant issues to the SC Exec Comm.

Thursday January 12, 2012…..Standards Committee Day 2:

- Carol Sedewitz, Frank McElvain and Steve Rueckert appointed to the SC nominating committee for the SC Executive Board.
  Above nominating committee presented the following slate to serve as at large members on the SC Exec Comm.: David Kiguel, Jason Shaver, and John Bussman.

- Top priority Standards for 2012 : CIP, BES Phase 2, 3 Part Communication, PRC and Frequency Response

- Proposed SC initiatives to align with 7 broad ERO goals: Maureen Long to distribute

- Linda Campbell on behalf of the SCPS……..development of a plan to allow RSAWs to be developed by the SDT……a Working Group, comprised of Compliance, Standards and NERC lawyers will develop the plan……when developed the plan will be submitted to the NERC BOT…..other questions to be answered …..do we eliminate Measures?…..do the RSAW's go to FERC when the standard is approved?....SC approved motion for WG to develop plan and present the plan to the SC.

- Maureen Long on behalf of the SCPS reviewed a plan to develop a Rapid Revision Process…….via a single portal process NERC would triage the request to determine if a question on some aspect of a standards requirements should be resolved either by Rapid Revision, CAN, Interpretation or Standard Development Process….. MOD 28 was handled in this manner and resolved via a Rapid Revision…

  Two motions approved by the SC……develop a formal Rapid Revision Procedure…..and develop a formal Triage Process.

- Ben Li on behalf of the Standards Committee Process Subcommittee……

  Presented red lined document on the Standard Drafting Team Scope…
  SC approved motion to accept proposed revisions.

  Two vacancies on the SCPS (Patrick Brown and Jason Shaver leaving)…….SC soliciting replacement candidates for the SCPS……Scott Miller volunteered……..

- Mike Gildea on behalf of the Communication and Planning Subcommittee….

Good feedback on the Weekly Standards Bulletin…considering some enhancements.

Two Standards and Compliance Workshops to be announced for 2012…….one in April and another in the Fall……..in between the two Workshops will be a Standards only 'State of the Standards' Webinar……..Webinar tentatively scheduled for July…..

- Laura Hussey discussion on the RBB……

RBB is cumbersome……NERC looking to verify that the existing RBB is comprised in a manner consistent with the Rules of Procedures. NERC will be looking to verify that affiliates are not represented by the same individual.

NERC also looking to verify existing affiliates.

NERC will be surveying members of the RBB between Feb and July to verify affiliates and representatives in order to verify integrity of voting process.

- Update on Regulatory:

Enforcement dates for Canadian entities will be updated shortly.

Regional UFLS Standards filed for SERC and TRE.

NERC submitted comments on the FERC NOPR for UFLS (continent wide).

David Kiguel commented on the recent Ontario rule that says the standards in Ontario are now effective when they become effective in the United States (FERC approval)…..as opposed to in the past upon NERC BOT approval.

- Update on the RSG (Herb):

MRO not supporting regional standards…..RFC on the fence…..Herb encouraged RFC to develop UFLS.

- I provided the SC with an update on the status of the NPCC Cost Effectiveness Procedure.

Motion for the SCPS to document the pros and cons of using the NPCC Cost Effectiveness Procedure and bring back a recommendation to the SC.

Thursday January 12, 2012…..Regional Standards Group Meeting:

- Review of Action Items:…..

    1. RSG Meeting Dates for 2012 distributed……item closed.
    2. Update Schedule for Protection System Mis-operations…..item closed.

- Update Rapid Development Project….Protection Systems Mis-Operations….45 day formal comment period expected in May…..Observation Report from Will Smith……(nothing to add).

- Agenda Item #8….**Action Item: Business Plan and Budget Common Assumptions 2013…. 8 Questions under Reliability Standards… NERC looking for a consensus responses …..**Howard to distribute Questions to the RSG……**regions will respond by Jan. 23 .**

- Agenda Item #9…Round Table Discussion….Discussion of Eastern Interconnect vs. Regional Standards…Will Smith to lead group reporting to the EMG…..group to explore the possibility of developing an (Eastern) Interconnection wide Standard…..Tuesday Jan. 17th @1pm (2 hrs)……initial conference call to discuss this concept…

- Howard will send out request for schedule updates(Development of Regional Standards).

- Agenda Item #11….discussion surrounding how the regions are posting their Regional Standards…..the NPCC approach…..once NERC BOT approves the standard the NPCC website will jump to the NERC website for current status and mandatory enforcement dates….suggested that all the Regions adopt a consistent approach…NERC website is improving in this regard……Provincial Dates were discussed at the SC and will be updated shortly.

- VRF Definitions and VSL Pro Forma Proposal…….conference call on Monday…….regions can participate.

- Agenda Item#13 Future RSG Dates….2/21 teleconference….3/12 teleconference…..4/13 Tampa.

- RFC has suspended the development of Regional Standards…..the issue is the impact of regional standards on multi regional entities

- FRCC, ERCOT, and SERC waiting for the DME continent wide before developing DME Regional Standard…..NERC and FERC pointed out that continent wide DME is not being actively developed….. FRCC, ERCOT, and SERC relying on regional criteria.

- Regional Standards and Variances…. ….concern about the SC telling a region how to prioritize development of a regional standard….. Howard Gugel whitepaper…….Howard and Don Jones will strip down the document and just answer the question of what is the

difference between a regional standard and a variance… the process language in the original document will be eliminated…..a conference call for the RSG on Feb. 3 will be scheduled to edit Howards and Don's product… once the RSG agrees on an answer to this question…… the RSG will report to the SC…..

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From:	Gerard J. Dunbar
To:	Guy V. Zito
Cc:	Lee R. Pedowicz
Subject:	Proposal for Alternative Standard Development Process
Date:	Thursday, January 12, 2012 8:43:45 PM
Attachments:	Alternative Standard Process A Jump Start.pptx

Guy…..I broke this SC discussion out of my general notes since the SC spent a great deal of time discussing this proposal and since it represents a major change in how standards are developed.

I've attached a presentation that NERC provided when they introduced the topic to the SC.

Wednesday January 11, 2012…..Standards Committee:

SC Agenda Item 8a:

Proposal for Alternative Standard Development Process

- Straw-man presented on proposal to significantly reviser the Standard Development Process…….SC looking for non starters or showstoppers in the straw-man at this time…..a draft concept will be presented to industry CEO's in a meeting in Washington in February…..after that meeting the concept will be returned to the SC for assignment to the SCPS……. this is not a decision point…..but NERC is looking for SC endorsement at this time to present these broad concepts to the CEO's…....no intent to bypass the SCPS……..SC and SCPS will be involved in the development details after the CEO meeting….

- Gerry Cauley's goal is to develop a standard in 12 months……. 6 years to develop a standard is too long….

- November BOT…..Allen Mosier appointed to lead a strategic review of the standards process…

- Ken Peterson NERC BOT commented on the proposal….. incremental improvement in standard development has been good…..but incremental improvement is not sufficient…… we need a breakthrough ……..the BOT supports any proposal that would significantly improve the process of developing the standard…..

- Paradigm shifts……

  1. Commit to a 12 month schedule…..
  2. Quality Review up front……
  3. Stakeholder input……necessary….but not on an individual entity basis…

- Drafting Team's will be eliminated….but function will be replaced by new groups……

- <u>New Groups:</u>

- **Technical Expert Panel (TEP) replaces the SDT.**

  Recognized experts who collectively have the necessary diversity to address all anticipated projects…..background in IEEE, EPRI, forums….appointed by the BOT for 2 years…..NERC would select from this pool to serve as the experts on a specific project….

- **Standards Consensus Group (SCG) replaces the Standards Committee**.

  Would assume many of the responsibilities currently assigned to the SC……managing the standards progress and development…..serves as delegates….assembles comments and ballots and represents industry segments…..they are also the balloters……no longer will we have an RBB of 1000 balloters….

  SCG…..would work with their industry segments and submit one comment form representing their industry…..this information is then channeled to the TEP…

- **Facilitation Group…….works to keep industry informed…**

  Technical Writing, Legal perspective, compliance perspective, facilitation, editing, project management….

  How to complete the standard in 1 year….have to assume 5 months to ballot……45 day comment period, initial ballot ,successive ballots, recirculation all combined will take 5 months….

  That means the first 7 months are where the standard is drafted……certain work (pre work) needs to be complete before the project starts….

- Particular concern about the role of the RSG.

  Many questions on segment representation, doing away with the Ballot Body, balance of interests within an industry segment…….NERC response: NAESB model could be used….

  Several suggestions made to take the low hanging fruit of this proposal and incorporate into the existing standard development process rather than change the whole process……..

  Question: Is this a change to the Standard Development Process?……(stakeholder comment and ballot)….or is it a change to Rules of Procedure?…..(comment only….no ballot)…NERC doesn't know yet…

  NERC agrees with the SC assessment that there are many challenging issues to this proposal…….NERC looking for suggestions to improve the proposal….

- **SC is asked to consider each of the 3 new proposed groups overnight and provide the SC with feedback as follows …….either you're completely opposed to a particular attribute of the proposal……or you can live with it with certain improvements……SC looking to finalize a straw-man to be presented to the CEO group in February.**

Thursday January 12, 2012…..Standards Committee:

- Standards Committee once again took up the question of the Alternative Standard Process:

  SC Members around the table commented after having the opportunity to consider the proposal overnight.

  Many commenter's supported the concept of the Technical Expert Group and the Facilitation Group…..however most viewed the idea of entities losing their ballot and the ability to submit individual comments via the establishment of the Standards Consensus Group as a non starter…

  SC will try and take the comments heard from the SC members (both positive and negative) and refine this straw-man in order to present a product to the CEO's in February.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Standards Committee Meeting

January 11, 2012 | 8-5 p.m. Pacific
January 12, 2012 | 8-3 p.m. Pacific
Sempra Energy
101 Ash Street
San Diego, CA 92101

Phone Number: 1-866-740-1260
Meeting Code: 4685998
Security Code: 321321

Introductions and Chair's Remarks

NERC Antitrust Compliance Guidelines and Public Announcement*

Agenda

Prior to the meeting, Maureen provided an introduction to SC activities and procedures for newly elected members.

1. **Review of Agenda (Approve)**

   discussion on Results based standards added to 4a.

   Approved

2. **Waiver of 5-day Rule (Approve)**

   Approved

3. **Consent Agenda (Approve)**

   a. October 28 QRAWG Standards Committee QRAWG Meeting Minutes* **(To be sent separately) (Ratify)**

   ~~a.~~b. December 7, 2011 Standards Committee Meeting Minutes* **(Approve)**

   ~~a.~~c. December 27, 2011 Standards Committee Quality Review Advisory Working Group and Executive Committee Meeting Minutes* **(Ratify)**

   Approved

4. **High Priority Projects, Activities, and Related Action Items**

   a. Status of Projects Identified as High Priority* **(Review)**

One Project Completed

- *Project 2007-07 Vegetation Management. This project was filed with the FERC on December 22, 2011.*

Six Projects on Schedule (+/- Two Weeks)

- *Project 2007-12 Frequency Response. However, it should be noted that the draft standard failed the initial ballot, which requires adding in a successive ballot. See schedule update.*
- *Project 2007-17 Protection System Maintenance and Testing*
- *Project 2008-06 Cyber Security Order 706*
- *Project 2010-05.1 Phase 1 of Protection Systems: Misoperations*
- *Project 2010-07 Generator Requirements at the Transmission Interface. However, it is unclear if the entire project scope has been completed or not. There may be additional work for this project team based on ongoing discussions.*

  Discussions are around NERC/FERC concerns with scope and capturing all the involved standards. PRC-005 may have been missed in the identification of involved standards.
- *Project 2010-17 Definition of BES. This project is showing slightly behind schedule, but this is due to this project being managed somewhat independently from its normal schedule, as it is being coordinated with the Rules of Procedure effort, has outside counsel working on the filing, and is being presented to the Board of Trustees in a special meeting.*

Seven Projects Behind Schedule

Analysis of timelines and delays are based on schedules adjusted and presented at the July SC meeting. It should be recognized that resource and posting conflicts may delay these projects further; Standards is developing process enhancements to manage these conflicts more aggressively in 2012.

- *Project 2006-06 Reliability Coordination. This project is approximately 5 months behind schedule (an additional month of delay added from last report). Its schedule has slipped this additional month due to resource conflicts associated with the holidays and finding volunteers to perform the Quality Review. Additionally, the project is somewhat linked with project 2007-02, and posting for 2006-06 is being coordinated with the posting of that project.*
- *Project 2007-02 Operating Personnel Communication Protocols. This project is approximately 6 months behind schedule (an additional month of delay added from last report). The additional delay has been caused by the team focusing on completing the 2009-22 Interpretation, as well as their reviewing and working to improve the quality of the 2007-02 work products.*

- *Project 2007-06 System Protection Coordination. This project is approximately 2 months behind schedule (an additional month of delay added from last report). The SDT is still finalizing its first draft of the new standard, and is expecting to deliver it for quality review in January.*
- *Project 2007-03: Real-time Operations. This project is approximately 2 months behind schedule (an additional month of delay added from last report). This project was delayed this additional month due to resource and posting constraints.*
- *Project 2007-09 Generator Verification. This project is approximately 2 months behind schedule (no change from last report).*
- *Project 2009-01 Disturbance and Sabotage Reporting. This project is approximately 3.5 months behind schedule (an additional month of delay added from last report) and is expected to get further behind schedule, as the draft standard failed its initial ballot and likely will require a successive ballot.*
- *Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves. This project is approximately 1 month behind schedule, as the team has been reviewing suggestions received from QR and making modifications to the standards.*

Discussion

Work going on currently about resources and will go like no more than 2 postings at a time.

SCPC will work with Andy to improve the reporting to the SC.

b. 2007-17 Protection System Maintenance and Testing – Report from Drafting Team **(Review)**

Charles Rogers (SDT chair) called in to report.

Project failed recirc. Ballot. Then the project was re-initiated with an expanded SDT. The new ballot resulted in even lower approval rate than the recirc.

Reasons are that:

- *New ballot pool formed with new ballotters in the pool. Drop in approval seems to be associated with new balloters.*
- *SDT made changesin response to comments. Expect to post again in March 2012.*
- *SDT expects successful ballot. May recommend another successive ballot if result is less than 75%.*
- *Compliance issues: FAQ indicated that compliance would audit to the language of the program it the program were more stringent than the standard. Compliance has indicated this is not correct. Audits look at the requirements, even if the entity has a more stringent program. Several negative comments were associated with this compliance issue.*

Recommendation on holding a technical session/webinar to discuss what the standard needs to contain to get it to a level of approval consensus, even at a reional level. Charles will bring to SDT.

c. Project 2007-12 – Frequency Response – Revised Project Schedule* **(Endorse)**

Unsuccessful initial ballot. Now working on the identified issues.

Schedule endorsed.

d. Lessons Learned from Rapid Revision of MOD-028 – Area Interchange Methodology* **(Review)**

Good:

- *Having a team already assembled to work*
- *Having members of the original SDT on that team*
- *Having limited scope*
- *Working via e-mail, rather than conference call meetings or in-person meetings*
- *Very short time to complete. Concept of Rapid Revision was developed in July 2011 and work commenced in August; final work products developed and being presented to the Board of Trustees in February 2012, for a total of approximately six months from start to finish.*

Bad:

- *Having to update the standard to reflect the latest templates, which was confusing or considered outside of scope by some*
- *Dealing with regulatory uncertainty associated with the VRFs and VSLs*
- *Similarly, the potential for coordination issues if the standard was in a state of development or regulatory action*
- *It is unclear what would have happened if the industry did not support this effort – would it have gone back to an interpretation? Would it have become another project and moved into successive ballot, rather than recirculation?*

Other Observations:

- *This could be used in areas other than interpretation, provide they have limited scope*
- *It may be of value to give IDTs the choice – interpret the standard or make a Rapid Revision. If the IDT had to return to the SC and request Rapid Revision, it could slow the process down.*

Discussion:
SC should have control on whether a project is treated as interpretation, rapid revision, CAN, RSDP, etc. It's in a proposal from the SCPS to have a single portal triage, later in the agenda.

e. Status of Outstanding Interpretations* **(Review)**

Current High Priority Projects:

Item	*Status*
Project 2008-10 Interpretation of CIP-006-1 for Progress Energy	*Recirculation ballot approved. (Quorum: 88.02%, Approval: 96.04%). Documents are being prepared for February Board of Trustees meeting.*
Project 2009-22 Interpretation of COM-002-2 for the IRC	*Recirculation Ballot approved. (Quorum 92.00%, Approval 94.58%). Documents being developed for February BoT meeting.*
Project 2009-26 Interpretation of CIP-004-1 for WECC	*The initial ballot for an interpretation of standard CIP-004-1 — Cyber Security — Personnel & Training, Requirements R2, R3, and R4, for WECC ended on January 19, 2010, and failed (Quorum: 84.21% Approval: 42.24%). Since at least one negative ballot included a comment, the results are not final. A second (or recirculation) ballot must be conducted. As part of the recirculation ballot process, the drafting team must draft and post responses to voter comments. The drafting team will also determine whether or not to make revisions to the balloted item(s). Should the team decide to make revisions, the revised item(s) will proceed to the successive ballot phase. The drafting team expects to submit the interpretation to NERC for Quality Review in December 2011 to prepare to post for successive ballot in January 2012.* *Same phrase and lack of clarity persist through all approved versions of the standard.*
Project 2010-INT-05 CIP-002-1 for Duke Energy	*The drafting team has reviewed the comments from the first formal posting. In*

	response, they have responded to the comments and have prepared the interpretation for initial ballot. Interpretation submitted to NERC for Quality Review on December 9, 2012, with expected posting for initial ballot in January or February 2012.
Project 2011-INT-01 Interpretation of MOD-028 for Florida *Power & Light Company*	*Recirc. Ballot completed. Quorum: 90.10%, Approval: 92.49%. Documents are being prepared for February BoT meeting.*

1.5 requests received. The .5 is because the request is still being edited (item 4f).

f. Request for Interpretation of TPL-003-0a: R1.3, R1.5 and TPL-004-0: 1.3, 1.4* **(Endorse)**

This interpretation request has been developed to address FERC concerns related to the term "Single Point of Failure" and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

Moved to SCEC for future action because the RFP is being reviewed by the submitter. Data request is labour intensive.

g. Recommendation to Convert Requests to Rapid Revision Process* **(Approve)**

The following three requests for interpretation all appear to meet the criteria for development under the Rapid Revision process as an alternative to processing as interpretations. The SC tol determine whether to address one or more of these requests as a Rapid Revision project.

1. *2010-INT-01 TOP-006-2 for FMPP*

Is the BA responsible for reporting generation resources available for use and TOP responsible for reporting transmission resources that are available for use? Does "appropriate technical information concerning protective relays" refer to protective relays for which the entity has responsibility?
FMPP advises that CAN-0028 addresses R1.2, but not R3. They are willing to accept clarification either through a CAN or through interpretation for R3.

2. *Project 2010-INT-03 TOP-002-2a for FMPP*

Clarity on BA obligations
FMPP advises that either a CAN or an interpretation is needed to provide clarification.

3. *RFI received on 1/28/2011 from Constellation Power Gen on VAR-002-1b*

Accepted for processing. Not assigned.

Discussion.
Motion to move all three standards interpretations forward with the Rapid Revision process.
Motion defeated.
New motion to move TOP-006-2 to Rapid Revision Process by te Real Time TOP team.
Would be doing this with the currently approved standards.
SDT should be asked on whether they will take the additional work.
Motion approved.

Motion to move the VAR-002 interpretation to Rapid Revision process.
Approved with 1 opposed and 3 abstentions.

h. ***Status of Results Based Standards.***

Herb: Industry has agreed but must wait for FERC's reaction. Test is FAC-003.

Andy R. reported that Results Based is now the norm; not used with legacy standards, but all new projects are using the Results Based process.
Proposal (Herb): post a list of the projects that are Results Based.
Assign to SCCPS to identify what additional information may be helpful.

5. **Standard Actions**

a. Compliance Application Notices* **(Prioritize)**

Mike Moon sent on December 21, 2011, to the SC a request to provide input to the prioritization of the compliance application notices (CANs) that have been requested but not yet developed.

The SCPS is expected to develop a simple set of criteria (similar to that proposed for interpretation requests) for use in prioritizing these CANs (high, medium, low) and present the criteria for adoption by the SC.

SCPS discussed yesterday and developed a set of factors to be weighted and put them in a spreadsheet similat to the project prioritization tool.

1. Does the request for clarity involve multiple standards or requirements in related standards? *(column C in Excel spreadsheet)*	**100 plus ten times number of standards**
2. Frequently violated standards + reliability impact (with VRF as a proxy) *(columns D and F in Excel spreadsheet)*	**100- High VRF 75 – Medium VRF Plus 50 if on top 20 most violated standards list**
3. Frequently dismissed violations *(column E in Excel spreadsheet)*	**100- High VRF 75 – Medium VRF Plus 50 if on top 20 most violated standards list**
4. Have there been multiple requests for clarification about compliance obligations? (column G in Excel spreadsheet)	**75 plus ten times the number of requests**
5. CIP standards (column H in Excel spreadsheet)	**Adder of 50**
6. Is the standard + requirement on the AML (or next year's AML)? (column I in Excel spreadsheet)	**Adder of 50 for standards on this year's AML – 25 for next year**
7. Requirements that apply to a large number of types of functional entities (column J in Excel spreadsheet)	**Adder of 10 for each type of functional entity**

Similar tool could work to prioritize interpretations.

SC asked to endorse.

b. NAESB Request to Elevate Priority of Two Standard Projects* **(Prioritize)**

Jim Castle (NYISO) presented.

NAESB has asked NERC to support one of its Business Practice efforts by making conforming changes to two standards that are not currently under active development.

The request is to make modifications to the INT standards (Project 2008-12 Coordinate Interchange) and IRO-006-EAST-1 in support of changes to the Interchange Distribution Calculator (IDC) and the manner in which the IDC curtails non-firm network service.

This effort is one which FERC has expressed significant interest, and some of the changes proposed under Informal project 2008-12 Coordinate Interchange would help address their concerns.

Options:

Some of the options available to the SC include:

- *Raising the priority of 2008-12 and expanding its scope to make limited modifications to IRO-006-EAST-1*
- *Creating a specific high-priority project to address the NAESB needs without making other changes to the INT standards*
- *Making no changes, and requesting NAESB consider alternate approaches*

Parallel Flow Visualization – Request

- *NAESB BPS requests the Executive Committee contact NERC about elevating the priority of Interchange Standard Development to tag intra-BA Point-to-Point so that NERC addresses this item within 2012. (FERC Order 693)*
- *This would also require a modification to IRO-006-EAST to modify R.3 and R.4 to support curtailment for intra-BA Point-to-Point. The timing for the changes to the INT and IRO standards will need to coincide with Parallel Flow Visualization moving into production.*
- *The NERC intra-BA tagging requirements should be coordinated with the NAESB Business Practices Subcommittee's work on Parallel Flow Visualization.*

No SC action taken – this is a business issue – NAESB can move ahead with a business practice. If there are reliability implications, then they will be addressed as necessary.

Ask Operating Reliability Subcommittee to identify reliability gaps.

c. Staff proposal to eliminate QRAWG* **(Approve)**

The Standard Processes Manual does not include any references to a Quality Review Advisory Working Group (QRAWG). The concept of having a QRAWG was developed by the SC and the SC has the authority to determine whether to continue with the QRAWG.

The QRAWG is a group of SC members who review the work of a drafting team in responding to the observations of a quality review team. The intent is for the QRAWG to determine whether the

drafting team has made a good faith effort at responding to the observations of the quality review team so that the documents are ready for posting.

Proposal:

Rather than have staff develop a summary of significant outstanding issues for QRAWG members to review, discontinue with the need to have a QRAWG meeting to review each set of documents prior to posting – instead, in those few situations where staff is concerned about a team's response to QR observations, direct staff to inform the SC EC and assemble the SC EC to review the work of a drafting team and determine whether to post the team's documents.

SCPS discussed the proposal and is not comfortable with reporting by exception only.

By doing so, the SC could be seen as not exercising its responsibility.

Motion to eliminate QRAWG but assign staff to bring significant unresolved issues to the SCEC.

Approved with 10 yeses, 4 nays and 1 abstention.

Report monthly to the SC.

d. Nominating Committee to Fill SC Executive Committee At-Large Positions* **(Appoint)**

The SC's Executive Committee consists of five members, the two officers and three at-large members. The at-large members are elected before the end of the second regularly scheduled meeting of the SC for a one-year term. The intent in deferring the election until the second meeting of the year is to allow the newly elected SC members an opportunity to participate in the election of the SC Executive Committee members.

The officers appoint a nominating committee, and the nominating committee identifies candidates to fill the three at-large positions. In accordance with the SC's Executive Committee Structure & Responsibilities document, the three at-large members must represent different industry segments and cannot represent the same segments that the officers previously represented. Allen Mosher previously represented Segment 4 and Ben Li previously represented Segment 2.

Proposal from Nominating Committee: Jason Shaver, John Bussman, David Kiguel

Approved.

6. **Committee Activities (Discuss)**

a. Goals for 2012 and Beyond*

ERO Strategic Goals

The Electric Reliability Organization (ERO) Strategic Goals through 2015 are summarized in the following key goals:

Goal 1: *The ERO will have clear, results-based reliability standards that provide for an adequate level of bulk power system reliability.*

Goal 2: *Bulk power system owners, operators, and users will demonstrate sustained cultures of learning and reliability excellence, built upon underlying foundations of compliance and effective risk management and mitigation.*

Goal 3: *The ERO will develop and maintain effective reliability performance measures and will continue to develop high quality reliability assessments based on long range and seasonal forecasts, as well as emerging issues.*

Goal 4: *Bulk power system owners, operators, and users will effectively manage risks from cyber and physical attacks and other high-impact, low-frequency events.*

Goal 5: *The ERO will balance the role of being a strong, independent enforcement authority, with one of providing owners, operators and users timely and transparent feedback on compliance and effective incentives for improving reliability.*

Goal 6: *NERC and the regional entities will execute statutory functions in a collaborative enterprise and thereby achieve efficiencies and effective process controls while leveraging the expertise of staff and reliability stakeholder resources.*

Goal 7: *The ERO will maintain an exceptional reputation as the trusted leader of the reliability community and instill a high degree of confidence in the reliability of the bulk power system.*

Review and identify if anything is missing.

Focus on Results Based Standards. Focus on cost/benefit assessments of standards.

Idea of having an SC member as a "mentor" for each SDT as a way for promoting the development of quality standards.

Standards Committee Goals:

Three Items from 2011

- *BES Definition*
- *TPL*
- *CIP V4*

Three Items for 2012

- *Expedite Standards Process*

- *Complete the following standards:*
  - *PRC standards (Misoperations)*
  - *Communications standards*
  - *CIP*
  - *BES Phase 2*
  - *Frequency Response*

Goals for 2012

Goal 1: The ERO will have clear, results-based reliability standards that provide for an adequate level of bulk power system reliability.

- ***Results based – communicate; track; implement***
  - *Revisit the reports from results-based and see if there is an opportunity to remove some requirements*
  - *Look at new standards and see if there are administrative requirements that should be removed*
  - *Have a reliability goal in the standards – not compliance goal –get away from micromanaging with respect to writing the standards*
  - *Challenge of standards that have requirements that are new – and include 'how to' steps in the body of the requirements*
  - *Consider assigning a SC member to monitor each standard – and reinforcing results-based format*
  - *Figure out how to get rid of low value requirements*
  - *Need to focus more on results-based standards*
  - *Consider having a performance-based requirement supported by a method of achieving the requirement with the option of following the sample or meeting performance another way*

Goal 4: Bulk power system owners, operators, and users will effectively manage risks from cyber and physical attacks and other high-impact, low-frequency events.

  - *Complete CIP V5 standards*

Work more closely with compliance

- *Meet more often with CCC*
- *Collect more info from compliance for input to standards development*
- *Consider more joint meetings with the CCC*
- *Consider moving compliance elements out of standards*
- *Conduct a mock audit for standards with significant changes*
- *Focus on reliability goal of standard when auditing –*
- *Enabling concepts: disconnect between idea of what an audit is and auditing work – for an auditor, his/her job is auditing "how" you did something – no focus on outcome – all about "Did you follow process?"*

Improve the standards process

- *More root cause analysis of why standard development doesn't move more rapidly*
- *Communicate expectations more explicitly with SDTs*
- *Ability to respond to emerging issues*

Changing Attitude/Setting Expectations

Goal 7 - The ERO will maintain an exceptional reputation as the trusted leader of the reliability community and instill a high degree of confidence in the reliability of the bulk power system.

- *Need to correct the assumption that every time something goes wrong, you can write a standard to prevent this from happening again . . .*
- *Instill stakeholder trust in difference between event analysis and investigation*
- *Help coach the industry on how to participate more constructively in submitting comments*
- *Goal for working with FERC (communication in writing)*
- *Communicate, for each project, whether the expectation is to raise the bar or clarify existing level of required performance . . . articulate this at the outset of a project . . . have a maturity model for standards where successive versions of standards are less prescriptive . . .*

Cost benefit analysis

Goal 3: The ERO will develop and maintain effective reliability performance measures and will continue to develop high quality reliability assessments based on long range and seasonal forecasts, as well as emerging issues.

- *ALRTF – integrate to standard development (ALR, Principles, standard drivers)*

b. Report from Process Subcommittee*

(a) *SDT to assist in developing RSAWs.*

SCPS will work with compliance to flash out how to implement.

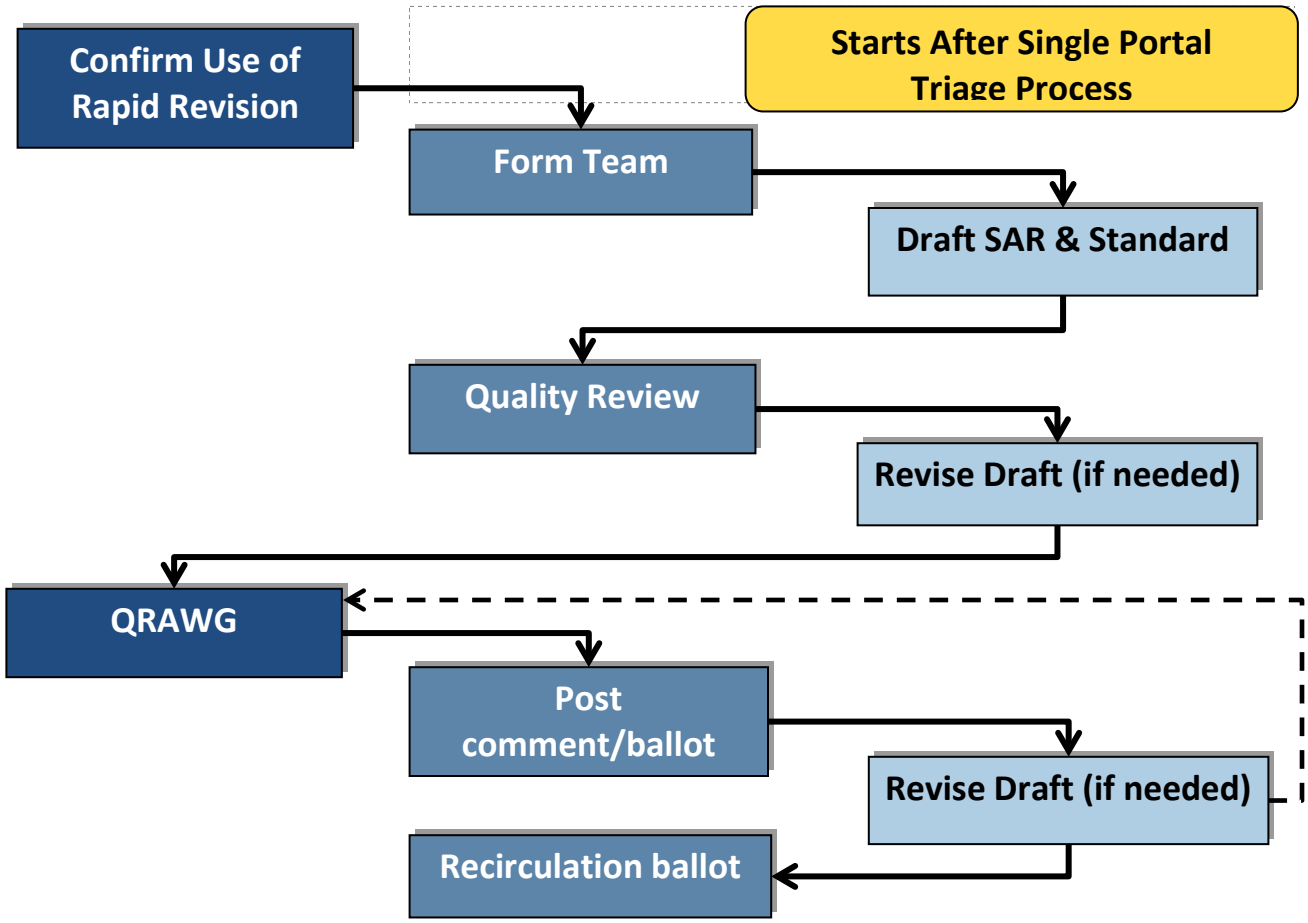
Once plan in place, come back to the SC.

Motion to endorse.

Approved.

(b) *Rapid Revision process documentation.*

The following process is proposed, including a triage as part of it.



SCPS will work with Mike moon and Valerie Agnew to develop the triage process.

Motion to endorse.

Approved.

(c) SDT Selection

Proposed revision to SDT scope and nomination form to ensure region representation and appropriate knowledge for the SDT.

Also changed the nomination form.

(d) Criteria and tool to prioritize CANs. See this agenda item.

Think on putting a limit on the maximum number of multipliers.

(e) SC members expectations.

(a) SC Members represent their segment, not their organization of personal views. Each member is expected to identify mechanisms for being in contact with members of the segment in order to maintain a current perspective of the views, concerns, and input from that segment. NERC can provide mechanisms to support communications if an SC member requests such assistance.

(b) SC Members base their decisions on what is best for reliability and must consider not only what is best for their segment, but also what is in the best interest of the broader industry and reliability.

(c) SC Members should make every effort to attend scheduled meetings, and when not available are required to identify and brief appropriately a proxy ahead of time and who is from the same segment. Standards Committee business cannot be conducted in the absence of a quorum, and it is essential that each Standards Committee make a commitment to being present.

(d) SC Members should not leverage or attempt to leverage their position on the SC to influence the outcome of standards projects.

Work of the SC is to focus on process and the quality of the product, not the technical content of standards.

Motion to approve and to include in every agenda package.

Approved

(f) New members to the SCPS are needed as Patrick Brown leaving the SC and PJM and Jason Shaver resigned to the SCPS.

*Laura will ask for confirmation of continu*ation of membership and *nominations will be sought if necessary.*

(g) Quality review earlier in the process.

Selection of pilot project will be reported to the SC at the next meeting.

c. Report from Communications and Planning Subcommittee*

Considering topics for 2 standards workshops (17 so far) to be held in 2012.

Also, standards status webinar in July.

Communication on results based standards planned.

Started NERC 101 presentations.

7. **Coordination (Review)**
   a. Coordination with Regulatory and Governmental Authorities

NERC submitted comments to 2 NOPRs.

Filed 2 regional standards.

Preparing BES definition filing due January 25.

French translation of standards for Quebec. Should NERC do it?

b. Coordination with Regional Managers

Issue with UFLS standards in 2 regions. These have developed regional standards that are in addition to the continent-wide standard.

White paper on regional standards and variances.

Cost effectiveness assessment was done in NPCC for the recently approved UFLS standard.

8. **Discussion Items**

a. Proposed Standard Process* **(To be sent separately) (Endorse)**

On October 13, 2010 Gerry Cauley met with members of the Standards Committee and other interested observers.

Following that meeting, members of NERC's standards staff began meeting and brainstorming ideas for an alternative standard development process that would maintain ANSI accreditation and also result in developing technically excellent standards in a shorter period of time with more efficient use of industry resources.

Proposed Standard Process

- *Commit to developing a standard in 12 months; publish and stick to schedules so that the stakeholders have more predictability about when to participate in commenting/balloting.*
- *Use technical experts to provide details needed to develop a standard, but don't force the experts to also write the requirements – use a team with a mix of skills – facilitation, technical writing, legal, and compliance to interview the experts and draft the standard using the experts' input; use an editor to edit the standard; and then have the experts verify the standard's requirements meet the reliability objective of the standard. Move the support provided during quality reviews into the initial stage of the standard development rather than after the standard has been drafted.*
- *Use "delegates" to work with constituents and develop comments/ballot proposed standards to provide fewer, more focused comments on proposed standards.*

- *The new process includes the following roles:*
  - *Technical Expert Panel (stakeholders)*
  - *Standards Consensus Group (stakeholders)*
  - *Facilitation (technical writing, legal perspective, compliance perspective, project management, process adherence, and editing – stakeholders/staff)*

Technical Expert Panel:

The Technical Expert Panel consists of a group of respected industry leaders with technical knowledge and established leadership skills that collectively represent diversity with respect to functional entity, region, interconnection, and nationality.

Before a new project is initiated, the members of the Technical Expert Panel are polled to identify a group of 5-7 who have the requisite expertise and can commit to the project schedule.

Standards Consensus Group (SCG):

The Standards Consensus Group is an elected group that serves as delegates to collect and consolidate comments from constituents, and vote on standards. Members of the SCG would be elected much as the Standards Committee members are elected today.

- *Reports to BOT SOTC*
- *Serves a staggered two-year term*
- *Appoints members to Technical Expert Panel*
- *Prioritizes standards development*
- *Authorizes project schedules/swapping*
- *Verifies compliance with the standard development process*
- *Commits to working under a code of conduct – supporting reliability of the grid*
- *Forms technical groups to collect/compile comments representing the industry segment.*

Facilitation:

A support group consists of people with a mix of facilitation skills who work on the development of each standard. Collectively the facilitation team includes a people who provide a variety of facilitation skills, including meeting facilitation, meeting administration, IT support, project management, technical writing, as well as input and review from a legal perspective; input and review from a compliance perspective; process oversight and formal editing. The makeup of the facilitation team would change to best support each project.

Presentation

Current Process:

Strengths:

- *Experts continue to volunteer*
- *Stakeholder participation high*
- *ANSI accreditation ensures due process*
- *Quality Review improving overall quality*

Weaknesses:

- *Commitment exceeds expectations*
- *Administratively burdensome for all involved*
- *Following ANSI rules takes 5 months for balloting*
- *Projects take too long*
- *Project schedule flexibility leads to unpredictability*
- *Compliance issues impacting standard development*
- *Many repeated comments.*

Three paradigm shifts:

- ***Schedule** – commit to a firm 12 month development schedule.*
- ***Technical Experts** – it's their knowledge and expertise we need, not their writing skills. Writing can be done by others with SMEs input.*
- ***Stakeholder Input** – it's necessary to hear from everyone – but not necessary to have this input on an individual basis. Groups can submit collectively.*

  Roles:
- *Technical Expert Panel (TEP)*
- *Standards Consensus Group (SCG) 9similar to current SC).*
  - *Decision Making Roles*
- *Facilitation Group (FG).*

Technical Expert Panel:

- *Pool of recognized experts with diversity recommended by technical committees, IEEE, EPRI, forums, etc.*
- *Appointed for staggered 2 year term. Selection process TBD.*
  - *Look at RSDP to determine expertise needed*
  - *Pool large enough to select 5-7 members for specific project*
  - *Diversity within pool & within areas of expertise*
- *Appointed by/report to BOT SOTC*
- *Commit to working under code of conduct*

Standards Consensus Group:

- *Responsibilities:*
  - *Manage overall standard development throughput (prioritization, schedule swapping, etc.)*
  - *Serve as delegate (commenting/balloting) for industry segment. Ballotter for the segment.*
  - *Commit to working under code of conduct*
- *Elected by stakeholders*
- *Report to BOT SOTC*
- *Serve staggered 2-year term*

Facilitation Group:

- *Technical writing*
- *Legal perspective*
- *Compliance perspective*
- *Facilitation*
- *Editing*
- *Project management*
- *Process adherence*

- *Administration*

Process Steps and timeline:

- *Default 12 Month Schedule:*
  - *From initial interview ➔ Recirculation Ballot*
  - *7 months to develop draft that meets 90% approval*
  - *5 months to ballot (ANSI requirements for accreditation)*

- *Work Far Ahead of Project Start Date:*
  - *Every Other Year – Appoint an Expert Review Panel*
  - *Ongoing – Manage Studies to Develop Technical Justification for Standards*
  - *Annually – update RSDP*
- *6 Months Before Project Start Date*
  - *Obtain commitment of Technical Experts*
  - *Refine project schedule (holidays, vacations, etc.)*
  - *Develop web page*
- *During the 3 Months Before Project Start Date*
  - *Conduct internal kick off meeting*
  - *Develop interview guide*
  - *Announce Technical Panel Meeting*
  - *Distribute Agenda Package for TEP's meeting*
- *1st 7 Months of Project*
  - *FG interviews TEP to collect information*
  - *FG develops initial draft & TEP reviews*
  - *FG hands draft to SCG*
  - *SCG shares with stakeholders/collects feedback/submits comments to FCG*
  - *FCG/TEP reviews comments from SCG/ develops final draft*
- *Last 5 Months of Project (Steps Required by ANSI)*
  - *45 day comment/ballot – consider/respond to comments*
  - *(If needed) 30 day comment/successive ballot – consider respond to comments*

- *10 day recirculation ballot*

Benefits:

- *Simplicity*
- *Less resources*
- *Increased certainty relative to schedule and product for all involved*
- *More focused, shorter time commitment for technical experts*

Challenges:

- *Do we have the right industry segments?*
- *What techniques can we use to facilitate collection of comments with industry segments that aren't well organized?*
- *During the 7 month development period, how can we collect informal comments in a way that uses technology to minimize the effort needed to document and share ideas. . .*
- *What industry groups already exist within each industry segment?*

Discussion

This is the product of NERC staff brainstorming.

Issue is speed versus quality.

Proposal eliminates SDTs and the SC as it exists today.

Ken Peterson (BoT):

Not endorsing but thinks some elements are good to gain efficiencies.

Need a breakthrough change

Urged group to maintain stake in process as it evolves.

Need to get to a different place; need significant efficiency/process changes.

Herb:

We are not here to force anything. No more incremental changes, we must look at the big picture.

Assume no additional NERC staff beyond 2012 approved numbers.

Issues:

How to manage collection/consolidation of comments

Diversity within segments

Resource constraints for Standards Consensus Groups.

How does the consensus group balance of interests?

Need to make sure everyone's voice is heard.

Technical Expert Panel: policy decision around any technical solution

Impact of compliance administration.

In NAESB each segment decides how it wants to allocate its seats and each segment has its own bylaws. Look at NAESB for further example.

NAESB has no Federal Power Act/law/regulation mandatory enforcement- mandatory only when referenced by FERC.

Ownership – entire ERO owns the projects.

Consider whether we need to keep ANSI accreditation.

What's the problem we are trying to solve?

Why does it takes so long to develop standards?

Huge change, nearly all refers to something to be done by NERC staff and limits stakeholders control.

Consider moving some of the ideas into the existing process.

Role of SCG is huge and compressed- look at the time involved to perform tasks.

Ron Parsons: Industry accepted/approved p rocess to make NERC the ERO. As such, it adopted many formal processes with formal timelines. Look at the benefits of having such process. It has many struggles bus many successes.

Resources issues have been there since day 1; it's not going away. It needs to be quantified.

SC members asked to think in terms of:

Schedule

Roles

Process

And on each say:

A: can live with the proposal

B: can live with proposal with some modifications

C: Indiferent

D: will not accept.

January 12 discussion

Ron: proposal contains some elements that could be used to improve the process.

Industry consensus is needed to implement any changes.

Mike G.: no commitment from the SC, actually only to review the process, Monitor overall results, including quality and timeliness of standards development work, and make recommendations to NERC Standards Committee and board regarding needed improvements

John B.: is the process broken? Whatever done, the balloting process must be preserved.

Room to make the process more efficient.

Linda: consensus segment comments are not realistic.

Some good elements can be used.

Jason: today's process works.

Carol: what makes the times shorter (e.g. BES definition) is members dedicated full time to the project. How many people are being proposed for the Technical Experts Panel.

Losing balloting ability is a non-starter.

Barry: not enough time to review and think about it.

b. Registered Ballot Body Update **(Review)**

Currently has over 1000 registered entities.

The SC charter gives the SC responsibility for it. No reviews have been performed to ensure entities are in the right segment. RBB is based on honour system.

Plan to write to rbb to verify information. Must be done without disturbing any ballot.

Two dimensions to it: one is software and the other is administration.

9. **Informational Items**

a. Drafting Team Vacancies*

b. Standards Committee Roster*

c. Highlights of Parliamentary Procedure*

d. Letters sent to CCC for Deviations from Standard Processes Manual *

~~9~~10. **Executive Committee Actions (Pre-authorize)**

a. Analysis of NERC Standard Process Results for Fourth Quarter 2011* **(Endorse)**

Must be filed by the end of January.

b. Project 2010-07 – Generator Requirements at the Transmission Interface Standard Drafting Team* **(Appoint)**

Two individuals nominated.

c. *Request for interpretation of TPL-003*

Approved.

~~10~~11. **Adjourn**

*Background materials included.

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Designing an Alternative Standard Process

A Jump Start

January 11, 2012

RELIABILITY | ACCOUNTABILITY






Topics

Why?

Current process – what does/doesn't work

Paradigm shifts

Roles

Process steps

Benefits

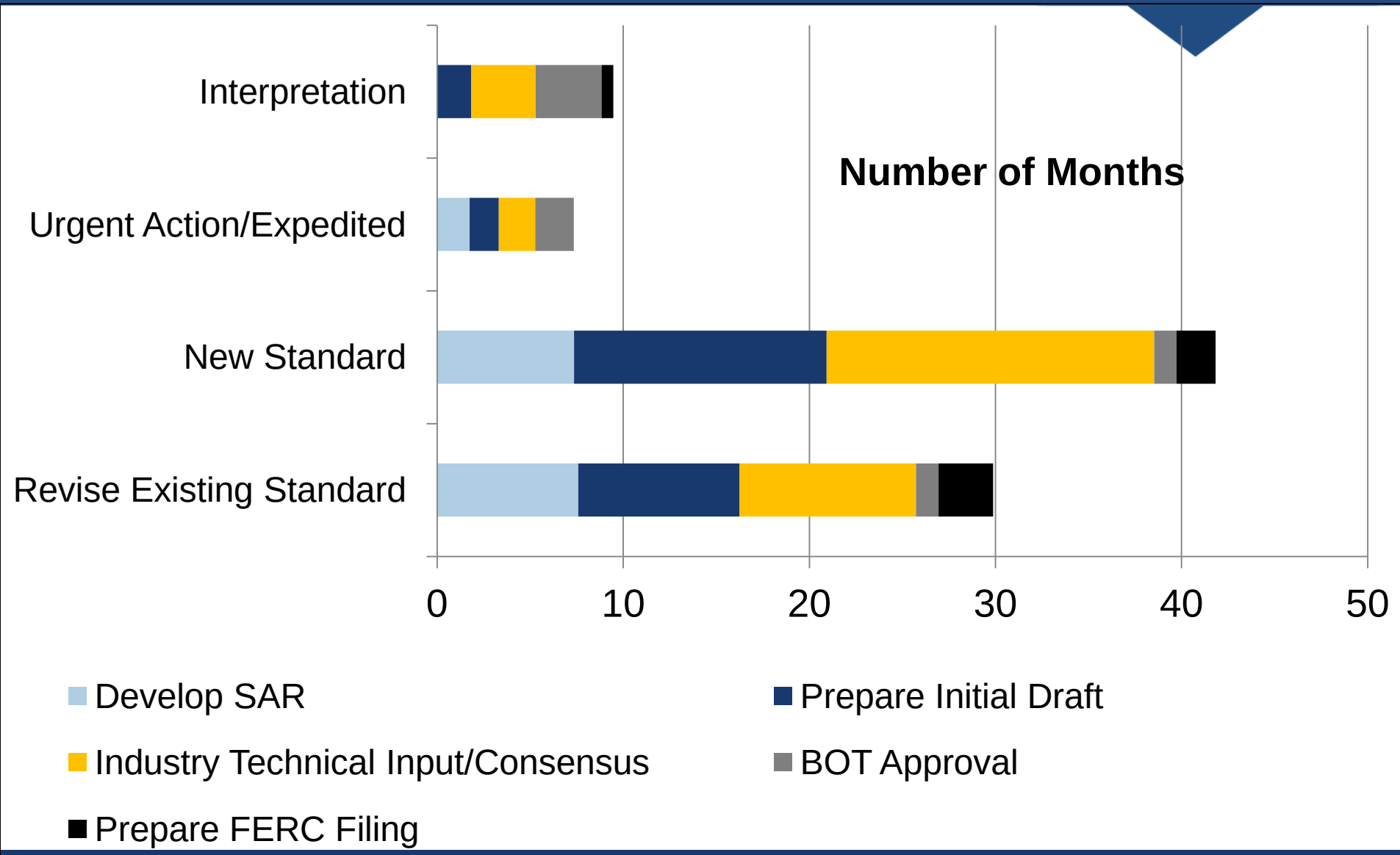
Challenges



Why?

- Well-written standards are critical to our core goal of reliability
- We as an industry are accountable for addressing reliability concerns in a timely manner
- To be successful, we have to provide quality products in a timely manner

Project Durations 2006-2010



History

- Three year assessment indicated we need to expedite standard development
  - "Band aids" helping improve quality, not really shortening development time
- October 13 meeting with Gerry – SC & staff agreed to look at process with goal of improving efficiency
- From November BOT Report – Allen appointed to lead strategic review of standards process – identify alternatives to improve efficiency while retaining ANSI accreditation – needed for Nov FERC & March NERC conference

Current Process: Strengths / Weaknesses

Strengths

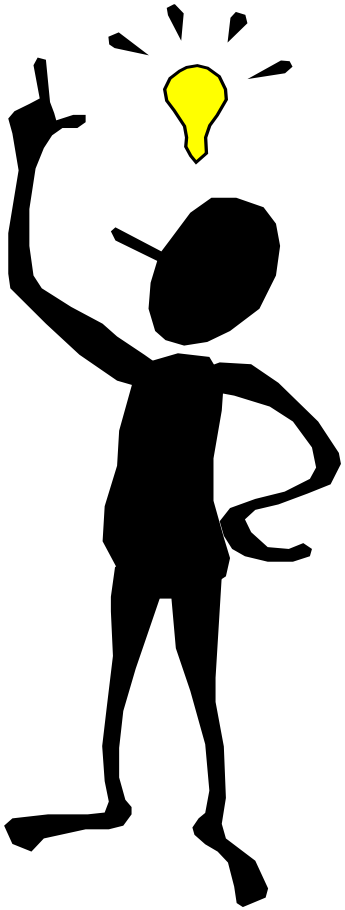
- Experts continue to volunteer
- Stakeholder participation high
- ANSI accreditation ensures due process
- Quality Review improving overall quality

Weaknesses

- Commitment exceeds expectations
- Administratively burdensome for all involved
- Following ANSI rules takes 5 months for balloting
- Projects take too long
- Project schedule flexibility leads to unpredictability
- Compliance issues impacting standard development

Paradigm Shifts

- **Schedule** – commit to a firm 12 month development schedule
- **Technical Experts** – it's their knowledge and expertise we need, not their writing skills
- **Stakeholder Input** – it's necessary to hear from everyone – but not necessary to have this input on an individual basis



Roles

- Technical Expert Panel (TEP)
- Standards Consensus Group (SCG)
  - Decision Making Roles
- Facilitation Group (FG)

Technical Expert Panel

- Recognized experts with diversity recommended by technical committees, IEEE, EPRI, forums, etc.
- Appointed for staggered 2 year term
  - Look at RSDP to determine expertise needed
  - Pool large enough to select 5-7 members for specific project
  - Diversity within pool & within areas of expertise
- Appointed by/report to BOT SOTC
- Commit to working under code of conduct



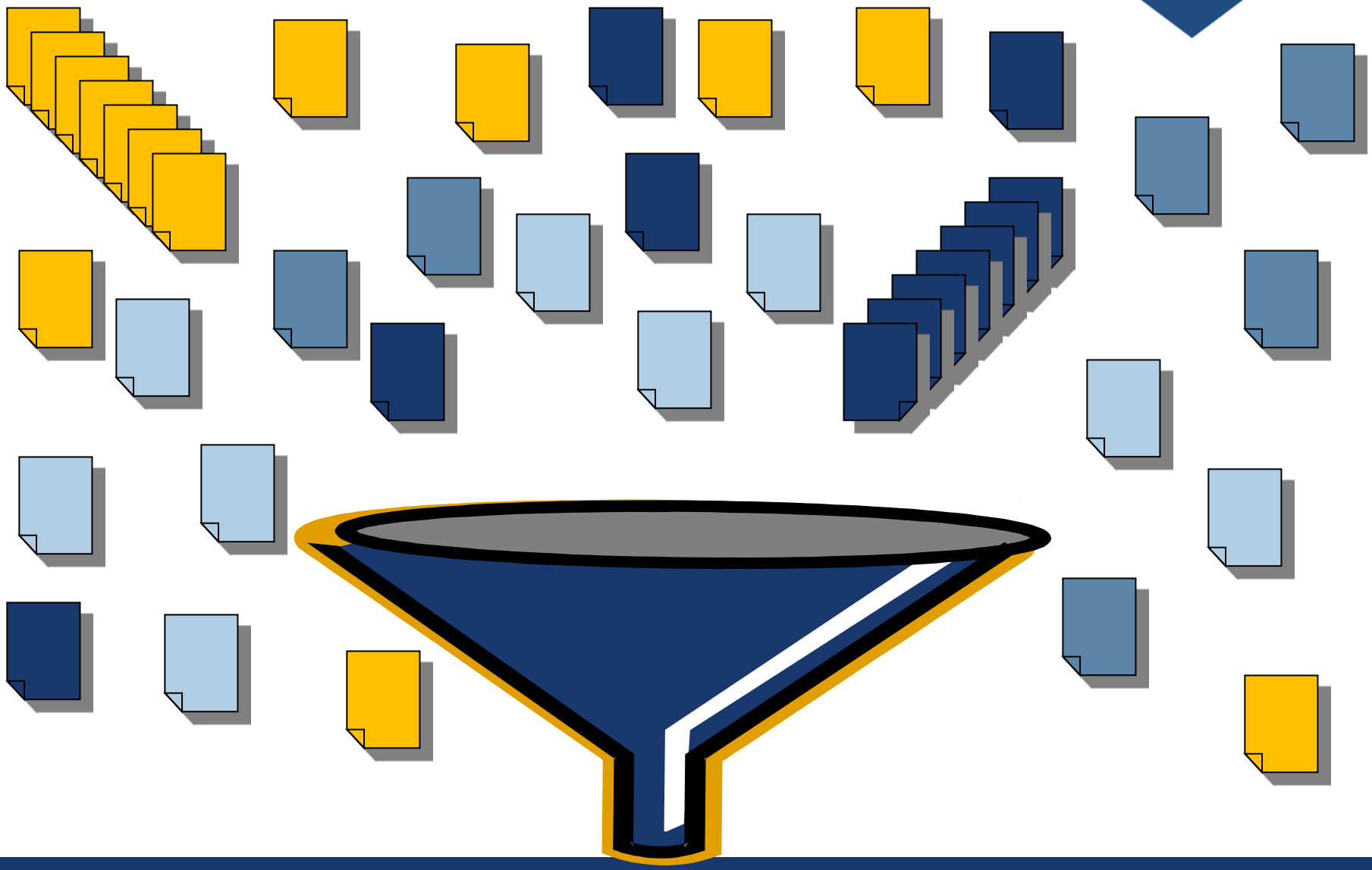
Standards Consensus Group

- Responsibilities:
  - Manage overall standard development throughput (prioritization; schedule swapping)
  - Serve as delegate (commenting/balloting) for industry segment
  - Commit to working under code of conduct
- Elected by stakeholders
- Report to BOT SOTC
- Serve staggered 2-year term



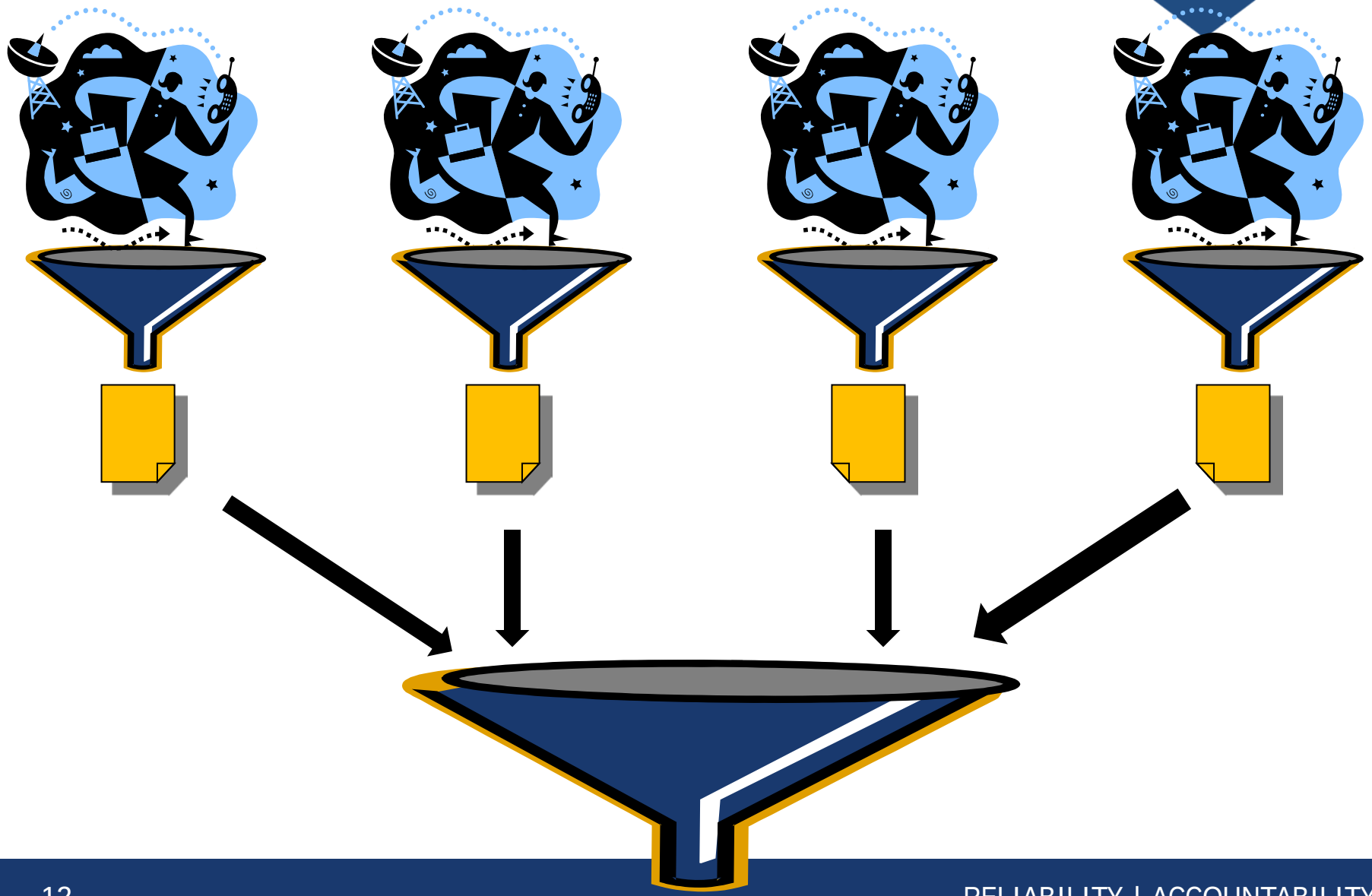
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Typical Comment Period



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Build Consensus Informally



Facilitation Group

- Technical writing
- Legal perspective
- Compliance perspective
- Facilitation
- Editing
- Project management
- Process adherence
- Administration



Process Steps & Timeline



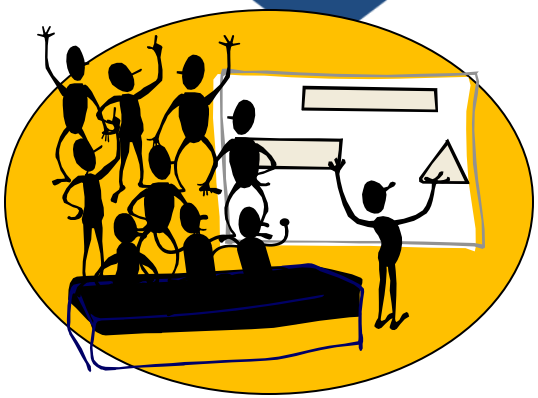
- Default 12 Month Schedule:
  - From initial interview → Recirculation Ballot
  - 7 months to develop draft that meets 90% approval
  - 5 months to ballot (ANSI requirements for accreditation)

- Work Far Ahead of Project Start Date:
  - Every Other Year – Appoint an Expert Review Panel
  - Ongoing – Manage Studies to Develop Technical Justification for Standards
  - Annually – update RSDP

Process Steps & Timeline

- 6 Months Before Project Start Date
  - Obtain commitment of Technical Experts
  - Refine project schedule (holidays, vacations, etc.)
  - Develop web page
- During the 3 Months Before Project Start Date
  - Conduct internal kick off meeting
  - Develop interview guide
  - Announce Technical Panel Meeting
  - Distribute Agenda Package for TEP's meeting

Process Steps & Timeline



- 1st 7 Months of Project
  - FG interviews TEP to collect information
  - FG develops initial draft & TEP reviews
  - FG hands draft to SCG
  - SCG shares with stakeholders/collects feedback/submits comments to FCG
  - FCG/TEP reviews comments from SCG/ develops final draft
- Last 5 Months of Project (Steps Required by ANSI)
  - 45 day comment/ballot – consider/respond to comments
  - (If needed) 30 day comment/successive ballot – consider respond to comments
  - 10 day recirculation ballot

Balance Speed & Quality?



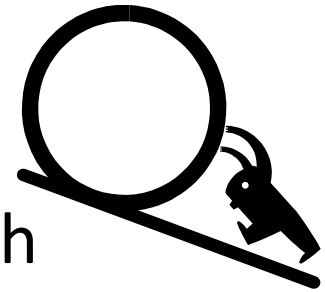
Balance Speed and Quality

Benefits

- Simplicity
- Less resources
- Increased certainty relative to schedule and product for all involved
- More focused, shorter time commitment for technical experts

Challenges?

- Do we have the right industry segments?
- What techniques can we use to facilitate collection of comments with industry segments that aren't well organized?
- During the 7 month development period, how can we collect informal comments in a way that uses technology to minimize the effort needed to document and share ideas. . .
- What industry groups already exist within each industry segment?



What Next?



From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Committee Special Election Results - New Segment 2 Nomination Period Open through February 9, 2012
Date: Friday, January 20, 2012 11:12:01 AM
Attachments: SC_Nomination_Form_2012-2013_seg_2_012012.doc

Standards Committee
Special Election Results

Segment 4 Election Complete

New Segment 2 Nomination Period Open through February 9, 2012

Segment 4 (Transmission Dependent Utilities) Election Results

The election to fill the vacant Standards Committee position representing Industry Segment 4 (Transmission Dependent Utilities) has ended, and Frank Gaffney of Florida Municipal Power Authority received a simple majority of the votes cast and has been elected.

New Segment 2 (RSOs/ITOs) Nomination Period Open

One of the Standards Committee members representing Industry Segment 2 (ISOs and RTOs), Patrick Brown, has resigned from the Standards Committee effective January 20, 2012 as he has changed employers and his new employer is in Industry Segment 5.

Registered Ballot Body members and others interested in NERC Reliability Standards are encouraged to submit nominations for individuals to fill the SC position for Segment 2. The vacant position is for a term that ends December 30, 2012.

With reliability standards mandatory for all bulk power system owners, operators, and users in North America, the SC's oversight role is increasingly important. The SC consists of two members from each of the ten Industry Segments that make up the Registered Ballot Body, with a goal of at least two members representing Canada. The SC is elected by stakeholders, and reports directly to the Board of Trustees. The SC meets monthly, either by conference call or in face-to-face meetings. Members who cannot travel to the meetings may participate by conference call. The SC Charter provides a description of the SC's responsibilities.

A nomination form is attached to this email for convenience and has also been posted on the NERC website. Please submit completed SC nomination forms to monica.benson@nerc.net no later than **February 9, 2012**.

Next Steps to Fill Standards Committee Vacancy in Segment 2

If multiple nominations are received, an election to fill the vacancy in Segment 2 will begin on February 17, 2012 and remain open through 8 p.m. on Tuesday, February 27, 2012.

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

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Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Agenda
Standards Committee Meeting

February 16, 2012 | 1-5 p.m. Eastern

Phone Number: 1-866-740-1260
Meeting Code: 4685998
Security Code: 321321

Introductions and Chair's Remarks

NERC Antitrust Compliance Guidelines and Public Announcement*

Review of Standards Committee Expectations *

Agenda

1. **Review of Agenda (Approve)**
2. **Waiver of 5-day Rule (Approve)**
3. **Consent Agenda (Approve)**
   a. January 11-12, 2012 Standards Committee Meeting Minutes* **(Approve)**
   b. January 30, 2012 Standards Committee Executive Committee Meeting Minutes* **(Ratify)**
   c. February 3, 2012 Standards Committee Executive Committee Meeting Minutes* **(Ratify)**
   d. Errata * **(Approve)** **(To be sent separately)**
4. **Active Projects, Activities, and Related Action Items**
   a. Status of Active Projects* **(Review)**
   b. Status of Outstanding Interpretations* **(Review)**
5. **Standard Actions**
   a. Project 2009-01 – Disturbance and Sabotage Reporting Project Schedule* **(Approve)**
   b. Compliance Application Notice Prioritization Criteria, Tool and Proposed Prioritization* **(Endorse)** **(To be sent separately)**
   c. Project 2008-06 – Cyber 706 Extended Posting Period* **(Approve)**
   d. Project 2010-INT-03 TOP-002-2a for FMPP* **(Authorize)**

6. **Committee Activities (Discuss)**
   a. Report from MRC, BOT, and BOT SOTC Meetings*
   b. Report from Communications & Planning Subcommittee
   c. Report from Process Subcommittee
7. **Coordination (Review)**
   a. Coordination with Regulatory and Governmental Authorities
   b. Coordination with Regional Managers
8. **Informational Items**
   a. Drafting Team Vacancies*
   b. Standards Committee Roster*
   c. Highlights of Parliamentary Procedure*
9. **Adjourn**

*Background materials included.

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Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

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

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

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Public Announcements

REMINDER FOR USE AT BEGINNING OF MEETINGS AND CONFERENCE CALLS THAT HAVE BEEN PUBLICLY NOTICED AND ARE OPEN TO THE PUBLIC

Conference call version:
Participants are reminded that this conference call is public. The access number was posted on the NERC website and widely distributed. Speakers on the call should keep in mind that the listening audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

Face-to-face meeting version:
Participants are reminded that this meeting is public. Notice of the meeting was posted on the NERC website and widely distributed. Participants should keep in mind that the audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

For face-to-face meeting, with dial-in capability:
Participants are reminded that this meeting is public. Notice of the meeting was posted on the NERC website and widely distributed. The notice included the number for dial-in participation. Participants should keep in mind that the audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

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Item 3a

Draft Meeting Minutes
Standards Committee Meeting

January 11, 2012 | 8-5 p.m. Pacific
January 12, 2012 | 8-3 p.m. Pacific
San Diego, CA 92101

1. Administrative Items

A meeting of the Standards Committee (SC) was held on Wednesday, January 11, 2012 from 8 to 5 p.m. and on Thursday, January 12, 2012 from 8-3 p.m. The agenda, attendance list, and meeting announcement are affixed as Exhibits A, B, and C respectively.

a. Introductions and Quorum

SC Chair Allen Mosher confirmed there was a quorum and welcomed all to the meeting. Allen noted that the new SC Election Procedure was in place and the chair and vice chair of the SC are no longer eligible to vote during regular meetings of the full SC. The chair and vice chair do have the right to vote during meetings of the SC's Executive Committee.

b. Conference Call Reminder and Antitrust Guidelines

Maureen Long reminded all that the conference call was open to all interested parties and reviewed the NERC Antitrust Compliance Guidelines.

c. Review of Agenda

Steve Rueckert motioned to approve the agenda as revised (addressing Item 5b at 1 p.m. on January 11 and Item 8a immediately after Item 5b an adding a discussion of results-based standards to Item 2a).

- *The motion was approved without objection or abstention.*

d. Waiver of 5-day Rule

Joseph Tarantino motioned to waive the 5-day rule.

- *The motion was approved without objection or abstention.*

2. Consent Agenda

Frank McElvain motioned to approve the following:

- October 28, 2011 QRAWG Standards Committee Quality Review Advisory Working Group Meeting Minutes
- December 7, 2011 Standards Committee Meeting Minutes
- December 27, 2011 Standards Committee Quality Review Advisory Working Group and Executive Committee Meeting Minutes
  - *The motion was approved without objection or abstention.*

3. High Priority Projects, Activities, and Related Action Items

a. Status of Projects Identified as High Priority

Andy Rodriquez reviewed the status of high priority projects and provided an explanation for the projects that are behind schedule. Standards committee members asked for more details on specific causes of delays.

b. 2007-17 Protection System Maintenance and Testing – Report from Drafting Team

Andy Rodriquez reported that this project failed recirculation; then was re-initiated and the drafting team was expanded to add several new members. The new initial ballot resulted in a lower approval than the previous recirculation ballot.

Standard drafting team chair, Charles Rogers, was called into the meeting and offered the following:

- Between the failed recirculation ballot and the new initial ballot, a new ballot pool was formed with many balloters in the new ballot pool who had not joined the previous ballot pool. The drop in approval seems to be associated with new balloters.
- Following the new initial ballot the drafting made several changes in response to comments.
- The team expects to move the standard forward with a posting in early March 2012 and expects a successful successive ballot, however if the ballot doesn't achieve an overall approval greater than 75%, the team may recommend another successive ballot.
- One issue that was raised by stakeholders and subsequently resolved involves a compliance issue. The team developed a "FAQ" document and in that document stated that auditors would audit to the language in an entity's maintenance program if the entity's maintenance program were more stringent than the standard. Subsequently the compliance department has indicated that auditors will audit to the performance in the requirement, even if the responsible entity's maintenance program is more stringent than the standard requires. Several negative votes were associated with this compliance issue, and the expectation is these negative votes will be changed to affirmative votes in the successive ballot.

c. Project 2007-12 – Frequency Response – Revised Project Schedule

Linda Campbell motioned to endorse the revised schedule for the Frequency Response project.

- *The motion was approved without objection with one abstention (Jason Shaver).*

d. Lessons Learned from Rapid Revision of MOD-028 – Area Interchange Methodology

Andy Rodriquez provided a brief report on the success of the use of the Rapid Revision process in revising MOD-028.

e. Status of Outstanding Interpretations

Andy Rodriquez provided a brief report on the status of the outstanding interpretations currently under active development.

f. Recommendation to Convert Requests to Rapid Revision Process

Laura Hussey proposed that the following three interpretations move forward for rapid revision:

- 2010-INT-01 TOP-006-2 for FMPP relative to Requirement R3
- Project 2010-INT-03 TOP-002-2a for FMPP relative to Requirements R2, R8, and R19
- RFI received on 1/28/2011 from Constellation Power Gen on VAR-002-1b relative to Requirement R1

Michael Gildea motioned to endorse moving all three interpretations forward for Rapid Revision.

– *The motion failed with six affirmative, five negative and three abstentions as shown below:*

Affirmative	Negative	Abstain
John Bussman	Linda Campbell	Klaus Lambeck
Michael Gildea	David Kiguel	Scott Miller
Michael Goggin	Steve Rueckert	Ronald Parsons
Frank McElvain	Carol Sedewitz	
Joe Tarantino	Jason Shaver	
Cathy Wesley		

Carol Sedewitz motioned to authorize the Real Time Transmission Operations drafting team to address the request for interpretation of TOP-006 with the Rapid Revision process.

– *The motion was approved with one opposed (Linda Campbell) and three abstentions (Silvia Parada Mitchell, Scott Miller, and Klaus Lambeck).*

Jason Shaver motioned to authorize moving the request for interpretation on VA-002 forward for development under the Rapid Revision process.

– *The motion was approved with one opposed (Carol Sedewitz) and three abstentions (David Kiguel, Klaus Lambeck and Scott Miller).*

g. Results-based Standards

Michael Gildea reported that the Communications and Planning Subcommittee had discussed results based standards and wanted to know the current status. Andy Rodriquez reported that the use of results-based is now the norm but that it is not used with legacy standards. All new projects are using results-based process.

A discussion led to the following recommendations:

- Assign the Communications and Planning Subcommittee to develop recommendations for ways to highlight what is happening with results-based standards.
- Consider posting a list of standards projects that are using the results-based process.

4. Standard Actions

a. Compliance Application Notices

Ben Li provided an overview of the compliance application notice (CAN) ranking criteria proposed by the SC Process Subcommittee and explained how the criteria could be used to prioritize the list of unaddressed CANs. Linn Oelker developed an excel spreadsheet that applies the criteria above and calculates a composite score for each proposed CAN. The CANs can then be sorted by score with the CANs having the highest score developed first.

John Bussman motioned to approve the following:

Volunteers from the SC PS will field test, refine, and then provide for the criteria and associated spreadsheet for review and endorsement during the SC's February SC meeting. Following that meeting, the SC will share the criteria with the other standing committees. On an interim basis, Ben Li will notify Val Agnew & Mike Moon and the chairs of the standing committees to provide them a status report and let them know that the SC will share the proposed criteria and associated spreadsheet by the end of the second week of February.

– *The motion was approved with one objection (Michael Gildea) and two abstentions (Jason Shaver and Carol Sedewitz).*

b. NAESB Request to Elevate Priority of Two Standard Projects

Jim Castle and Andy Rodriquez provided a summary of NAESB's request to consider elevating the priority of revisions to standards to support changes to the Interchange Distribution Calculator (IDC) and the manner in which the IDC curtails non-firm network service.

SC members indicated that the issue seems to be more business related than reliability related and recommended that the Operating Reliability Subcommittee identify any reliability gaps associated with the modification to the IDC and report any gaps to the SC for further consideration.

c. Staff Proposal to Eliminate Quality Review Advisory Working Group (QRAWG)

Maureen Long proposed retiring the QRAWG and reporting significant issues with draft standards to the Standards Committee for resolution.

Steve Myers motioned to eliminate the QRAWG but assign staff to bring significant unresolved issues associated with the QR to the Standards Committee's Executive Committee.

– *The motion was approved with three opposed (Frank McElvain, Jason Shaver, and Alice Ireland) and no abstentions.*

d. Nominating Committee to Fill SC Executive Committee (SCEC) At-Large Positions

Allen Mosher appointed the following to serve as the nominating committee:

- Frank McElvain
- Steve Rueckert
- Carol Sedewitz

The nominating committee returned later in the meeting with the following slate of nominees who self-nominated for the three at-large positions:

- John Bussman
- David Kiguel
- Jason Shaver

Joseph Tarantino motioned to appoint John Bussman, David Kiguel and Jason Shaver to the SCEC:

– *The motion was approved without objection or abstention.*

5. Committee Activities

a. Goals for 2012 and Beyond

Allen Mosher led a discussion that resulted in identification of the Standards Committee's goals for 2012 linked to the ERO's strategic goals. **(Exhibit D)**

b. Report from Process Subcommittee

Ben Li reported on the following activities supported by the work of the Process Subcommittee:

Reliability Standard Audit Worksheets (RSAWs)

Linda Campbell reported that the Process Subcommittee recommends having standard drafting teams work with the compliance staff in developing RSAWs. Linda noted that there is a need to develop a formal process to support this activity.

Michael Gildea motioned to endorse the following plan:
Linda Campbell will lead a small team working with Mike Moon and other compliance staff, standards staff, standard drafting team members, and perhaps some legal staff, to identify and document how drafting teams can assist in the development of RSAWs. Once there is a draft plan, Linda will bring the plan to the SC and the BOT CCC for open discussion in the industry.

– *The motion was approved without objection and one abstention (Frank McElvain).*

Rapid Revision Procedure (Exhibit E)

Ben Li and Linda Campbell provided an overview of the Rapid Revision process formalized by the Process Subcommittee. Linda Campbell reported that she will be working with a small team to further develop the concept of having a single portal for submittal of all requests for clarification on a standard, with a triage process to determine the appropriate direction for responding to the request for clarification. Clarity could be provided by a normal revision to the standard, by an interpretation, by a compliance application notice, or by a rapid revision to the standard.

John Bussman motioned to endorse the Rapid Revision process and develop a draft "triage" process:

– *The motion was approved without objection or abstention.*

Standard Drafting Team Scope Document (Exhibit F)
The Process Subcommittee proposed revisions to the subject document to achieve the following:

- More clearly identify the conditions for replacing a team member and the conditions for replacement
- More clearly identify a nominee's expertise with respect to regional criteria
- Verify that the nominee has corporate support for participation

Steve Rueckert motioned to approve the revised SDT Scope Document.

– *The motion was approved without objection or abstention.*

SC Expectations Document (Exhibit G)
Linda Campbell motioned to approve the SC Expectations document and direct staff to include this in every agenda package.

– *The motion was approved with one opposed, (Jason Shaver) and five abstentions, (Diane Barney, John Bussman, Alice Murdock, Michael Gildea, and Carol Sedewitz).*

Process Subcommittee Membership
Linda Campbell motioned to endorse opening the membership of the Process Subcommittee to additional SC members and other stakeholders if necessary.

– *The motion was approved without objection or abstention.*

Adding Quality Review Earlier in the Process
Laura Hussey reported on the results of the test of providing a drafting team with an informal quality review earlier in the process. Project 2010-05.1 Protection Systems: Phase 1 (Misoperations) provided a preliminary draft of its standard and this was reviewed independently by three people representing legal, compliance and standards. The short window between the time the drafting team provided the draft and the time the drafting team needed the draft did not allow time for a meeting of the quality reviewers to consolidate the observations into a single document.

The team reported that getting feedback earlier was positive, but because the feedback wasn't consolidated, the feedback was at times contradictory, diminishing its usefulness. The team recommended having the quality reviewers work directly with the team to refine the standard.

The standards staff will find another project that is working on a preliminary draft and will try to provide quality reviewers who can work directly with the team.

Update on NPCC Cost Effectiveness Initiative
Allen Mosher asked for an update on NPCC's cost effectiveness initiative. Gerry Dunbar reported that in NPCC, there is an effort to accompany draft standards with cost effectiveness analyses. NPCC's Regional UFLS standard was presented to the NPCC board with a cost effectiveness report.

c. Report from Communications and Planning Subcommittee
Michael Gildea reported that the Communications and Planning Subcommittee met on January 10, 2012 and reviewed the feedback from the last workshop. The feedback was positive and will be used to develop tentative formats for the 2012 workshops. A workshop will be held in April on the west coast, and one in the fall on the east coast. There will be a "NERC 101" session at the begging of each of these workshops.

Mike also reported the following:

- The weekly standards bulletin has been well received.
- A "State of Standards" webinar in scheduled for July 2012.
- There is a need for more communication on results-based standards and more communication on the status of high priority standards to keep the industry informed about progress in these areas.

6. Coordination

a. Coordination with Regulatory and Governmental Authorities
Willie Phillips reported that NERC submitted comments on both the UFLS and TPL footnote b Notices of Proposed Ruling during late December, 2011 and is working on developing several filings in support of recently approved continent-wide and regional standards.

Herbert Schrayshuen reported that in Quebec, standards are translated into French. The Regime is verifying that the interpretation from English to French was accurate.

Herb also reported that the standards staff has completed updating the standards web pages for United States enforcement dates and will now focus on updating the web pages for Provincial enforcement dates.

b. Coordination with Regional Managers
Herbert Schrayshuen reported that the Midwest Reliability Organization has not developed any regional standards and has indicated it does not plan to do so. One or two other regions (including Reliability*First* Corporation) are questioning the need to continue to develop regional standards.

The Regional Standards Group (RSG) has a meeting scheduled for January 12, 2012 and will start identifying regional standards development support needed for inclusion in the 2013 Business Plan & Budget.

The RSG approved a process for NERC review of Regional Standards and is working on the process for coordination of proposals for regional standards and variances.

7. Discussion Items

a. Proposed Standard Process (Exhibit I)

Maureen Long and Laura Hussey provided an overview of an alternative standard development process that includes major paradigm shifts:

- Instead of appointing technical experts to a drafting team with the expectation that the drafting team would do all the work associated with developing a standard, appoint technical experts to a technical panel and use the members of that panel to provide the information needed to draft the technical details of a standard
- Instead of allowing projects to have an open-ended duration, establish a 12 month project development schedule from initial SAR posting through the recirculation ballot
- Expand the responsibilities of the Standards Committee to include more close work with segment members in collecting and consolidating comments and then balloting consensus views on proposed standards

A summary of the response to the proposed alternative process is included as Exhibit I.

b. Registered Ballot Body Update

Laura Hussey provided an update on the status of the Registered Ballot Body (RBB). There are over 1,000 members of the RBB. While the language in the registration criteria includes a statement indicating that the intent is to refresh the RBB on an annual basis, this hasn't happened and there are members of the RBB who are not active and have not been active for many years – and others who are registered for the incorrect segment.

The intent is to begin, mid February 2012, asking members of the RBB to self-report on their interest and eligibility for continued participation in the RBB in a specific industry segment with a goal of completing the verification process by mid-July

The Standards Committee has a role in addressing registration disputes, and the standards staff plans to seek assistance of the Standards Committee when addressing unusual registration scenarios.

8. Executive Committee Actions

Joe Tarantino motioned to preauthorize the Standards Committee's Executive Committee to act on the following if they are presented to the Standards Committee before the February 11, 2012 meeting:

- Analysis of NERC Standard Process Results for Fourth Quarter 2011
- Project 2010-07 – Generator Requirements at the Transmission Interface Standard Drafting Team
- Request for Interpretation of TPL-003-0a: R1.3, R1.5 and TPL-004-0: 1.3, 1.4
  - *The motion was approved without objection or abstention.*

9. Adjourned

New Action Items:

Communications & Planning Subcommittee:

- Work with Andy Rodriquez to develop a proposal on how to modify monthly reports to SC on project status (For February 2012 SC Meeting).
- Consider providing support to communication about results based standards – nothing posted that is easy to find on current status.
- Consider helping the PRC-005 team with communication outreach.

Process Subcommittee:

- Laura Hussey - send an email to scps_plus to request feedback on interest in participating with the SCPS.
- Linda Campbell – lead effort to develop single portal triage process with Mike Moon.
- Linda Campbell – lead effort to draft a process for using drafting teams to assist in developing RSAWs.
- Bring prioritized CANs to February 2012 SC meeting.

Staff:

- Mallory Huggins - Share the outcome of the GOTO discussion with the SC.
- Herbert Schrayshuen - Follow-up on cost effectiveness procedure from NPCC and report to Ben Li for Process Subcommittee.

Meeting Minutes
Standards Committee Executive Committee

January 30, 2012 | 10:00 a.m. Eastern

1. **Administrative Items**

Introductions and Quorum

Allen Mosher verified there was a quorum with the following three of the five members of the SC EC present:

- Allen Mosher
- Ben Li
- David Kiguel

Also in attendance:

- Laura Hussey
- Maureen Long
- Herb Schrayshuen
- David Taylor

NERC Antitrust Compliance Guidelines and Conference Call Reminder

Maureen Long reviewed the NERC Antitrust Compliance Guidelines and Allen Mosher reminded all that the conference call was open to all interested parties and everyone should recognize that it is not possible to know everyone who may be listening to the call.

Analysis of NERC Standard Process Results for Fourth Quarter 2011

The team recommended the following action plan to recognize the importance of closing the reliability gap while also trying to use limited resources most efficiently:

2. **Analysis of NERC Standard Process Results for Fourth Quarter 2011**

Ben Li motioned to endorse the *Standard Process Results for Fourth Quarter 2011* for inclusion in NERC's quarterly filing to FERC with the following modification:

- Add some words to identify that the Standards Committee put interpretations on hold while formalizing a procedure to improve transparency and visibility of managing interpretations.

– *The motion was approved without objection or abstention.*

3. **Project 2010-10 – Generator Requirements as the Transmission Interface – Appeal**

Herbert Schrayshuen reported that he received an appeal from Exelon in which Exelon proposed that a substantive modification was made to FAC-003-3x – Transmission Vegetation Management Program between the successive and recirculation ballots and moving to a recirculation ballot was a violation of the process.

Herb informed those present that he is collecting data and will file a written response to the appellant within the 45-day response period identified in the Standard Processes Manual. In addition, Herb reported that he removed the FAC-003-x standard from the set of documents submitted for action during the February 9, 2012 board meeting to prevent the board from taking action on something that may need to return to standard development.

4. **Adjourned**

Meeting Minutes
Standards Committee Executive Committee

February 3, 2012 | 4:00 p.m. Eastern

1. **Administrative Items**
   Introductions and Quorum
   Allen Mosher verified there was a quorum with the following four of the five members of the SC EC present:
   - John Bussman
   - David Kiguel
   - Ben Li
   - Allen Mosher

   Also in attendance:
   - Scott Barfield
   - Diane Barney
   - Laura Hussey
   - Maureen Long
   - Andy Rodriquez
   - Herb Schrayshuen
   - David Taylor

   NERC Antitrust Compliance Guidelines and Conference Call Reminder
   Maureen Long reviewed the NERC Antitrust Compliance Guidelines and reminded all that the conference call was open to all interested parties and everyone should recognize that it is not possible to know everyone who may be listening to the call.

2. **Staff Recommendation to Accept a Request for Interpretation of TPL-003 and TPL-004 from the System Protection and Control Subcommittee**
   David Kiguel motioned to endorse NERC's standards staff's recommendation to accept the request for interpretation of TPL-003 and TPL-004 from the System Protection and Control Subcommittee as valid.

   – *The motion was approved without objection or abstention.*

   The SC EC indicated support for forming a drafting team using volunteers from the Project 2006-02 – Assess Transmission and Future Needs SDT augmented with other stakeholders with experience

working on developing protection-related standards, and for treating this request for interpretation with high priority.

3. **Adjourn**

Status of Active Projects

Andy Rodriquez will review the following information on the projects under active development.

Review of Report Changes and Format

One Rapid Revision Awaiting Board Approval

- Project 2011-INT-01 Interpretation of MOD-028 for Florida Power & Light Company

One Project Partially Completed

- Project 2010-17 Definition of BES. The first part of work for this project was filed with the FERC on January 25, 2012.

Two Rapid Revisions in Progress

- Project 2010-INT-01 Interpretation of TOP-006 for FMPP
- Project 2011-INT-02 Interpretation of VAR-002 for Constellation Power Gen

One Project Ahead of Schedule

- Project 2010-07 Generator Requirements at the Transmission Interface. This project is approximately six months ahead of schedule, due to a reduction in the overall amount of work required.

Six Projects on Schedule (+/- Two Weeks)

- Project 2007-12 Frequency Response.
- Project 2007-17 Protection System Maintenance and Testing.
- Project 2008-06 Cyber Security Order 706.
- Project 2009-01 Disturbance and Sabotage Reporting. See proposed new project schedule.
- Project 2010-05.1 Phase 1 of Protection Systems: Misoperations.
- Project 2010-17 Definition of BES – Part 2. Project is awaiting development of new schedule.

Six Projects behind Schedule

Analysis of timelines and delays are generally based on approved delivery dates from previous SC meetings. It should be recognized that resource and posting conflicts may delay these projects further; Standards is developing process enhancements to manage these conflicts more aggressively in 2012.

- Project 2006-06 Reliability Coordination. This project is approximately 5 months behind schedule (no change).
- Project 2007-02 Operating Personnel Communication Protocols. This project is approximately 2.5 months behind schedule (3.5 months of delay removed from last report). The project schedule has been accelerated by removing an extra comment period that was determined to be unnecessary.
- Project 2007-06 System Protection Coordination. This project is approximately 2 months behind schedule (no change). However, the team has received extensive feedback from the quality review of its standard, and it is expected that additional time will be needed to review the proposed changes and move the standard forward.
- Project 2007-03: Real-time Operations - This project is approximately 2.5 months behind schedule (an additional half-month of delay added from last report). This project was delayed this additional month due to the desire to limit the amount of concurrent postings. Because TOP-001 did not pass ballot, it is expected that more time will be needed to add an additional successive ballot
- Project 2007-09 Generator Verification. This project is approximately 3.5 months behind schedule (an additional 1.5 months of delay added from last report). These delays are due to an underestimation of the amount of work associated with performing quality reviews and responding to the QR feedback on these standards.
- Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves. This project is approximately 2 months behind schedule (an additional month of delay added form last report), as the team has been reviewing suggestions received from QR and making modifications to the standards.

Attachment 4aii

S - SC Project Step (Multi-Row)

S - SC Project Step (Multi-Row)

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	Name		
Program: **Standards Development** (16)			
Priority: **Normal** (7)			
	Project 2006-06 Reliability Coordination **Description:** To ensure that the reliability-related requirements applicable to the Reliability Coordinator are clear, measurable, unique and enforceable; and to ensure that this set of requirements is sufficient to maintain reliability of the Bulk Electric System.	**Leadership:** Mike Hardy (SoCo) **NERC Staff:** Scott Barfield-McGinnis **SAR Date:** 12/16/06 **Team Assembly:** 6/5/07 **Target Finish:** 1/24/12 **Forecast Finish:** 6/27/12 **SPM Step:** Analysis of Cmts or FT **Related Standards:** COM-001, IRO-016, IRO-015, IRO-002, IRO-014, IRO-001, COM-002, IRO-003, IRO-005 **Last Update:** 2/6/12	**Status:** First set of standards: The industry approved IRO-002, IRO-005, and IRO-014 on July 25, 2012. The BOT approved the standards at their August 4, 2012 meeting. The current and previous coordinator met with NERC Legal and other staff on 1/31 regarding the filing for these BOT approved standards in this project. Discussion is on-going regarding the timing of the filing due to coordination with the RTOSDT and OPCPSDT. Filing may be delayed until the RTOSDT set of standards is approved by the BOT and is ready to file. Next steps are to determine when to file. Second set of standards: The QRAWG/SCEC approved posting the second set of standards (i.e., COM-001, COM-002, and IRO-001) for successive ballot on a conference call on December 27th. Currently, the second set of three standards were posted for a 30-day industry comment which started on January 9, 2012. A successive ballot is being conducted in the last 10 days of the comment period ending on February 8, 2012. The project is about three weeks behind and the coordinator has reached out to the Chair to tighten the schedule; however, due to SDT members other commitments, alternative remote meetings were not attainable. Next steps, the coordinator and chair have an arranged team meeting to develop the consideration of comments to March 8, 2012 in Tampa, FL at the FRCC office.
	Project 2007-03: Real-time Operations **Description:** Clarify requirements for real-time operations of the Bulk Electric System in the cited standards. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO and regulatory authorities	**Leadership:** Jim Case, Entergy **NERC Staff:** Edward Dobrowolski **SAR Date:** 4/16/07 **Team Assembly:** 12/11/07 **Target Finish:** 2/20/12 **Forecast Finish:** 5/2/12 **SPM Step:** Successive Ballot **Related Standards:** TOP-004, TOP-005, TOP-006, PER-001, TOP-007, TOP-001, TOP-002, TOP-003, TOP-008 **Last Update:** 2/3/12	**Status:** Ballot closed on January 19, 2012. The SDT is working on their response to comments. TOP-001 did not pass ballot but TOP-002 & -003 did. TOP-001 will have to go to a successive ballot. TOP-002 can go to recirculation ballot. TOP-003 is also going to have to go to a successive ballot due to a change in applicable entities. In addition, PRC-001 has to be posted as this SDT took on the deletion of 3 requirements from PRC-001 that can be handled with the TOP-003 data specification concept. Same SDT also working on two rapid revisions: one for TOP-006 and one for TOP-002 - both arising out of interpretation requests from FMPP. This project is behind schedule due to the length of time it took to reconcile QR comments for the last posting and a management decision to postpone the last posting due to the amount of projects out for comment/ballot. Every attempt will be made to pick up time on this iteration but with TOP-001 not passing ballot this project is not going to regain any time and will in fact fall further behind schedule as TOP-001 has to go to a successive ballot again.
	Project 2007-09 Generator Verification **Description:** Requires upgrading existing requirements for generators to verify their capabilities to ensure that accurate data is used in model to asses the bulk electric system.	**Leadership:** Lee Taylor Ken Stenroos Dave Kral **NERC Staff:** Stephen Crutchfield **SAR Date:** 4/3/07 **Team Assembly:** 9/12/07 **Target Finish:** 10/19/12 **Forecast Finish:** 2/1/13 **SPM Step:** Quality Review **Related Standards:** PRC-024, MOD-027, MOD-025, MOD-	**Status:** MOD-025, MOD-07 and PRC-019: The standards were posted for a 30-day formal comment period from June 15 - July 15, 2011. The team has met twice to develop responses to comments and develop revisions to the standards. The team submitted the proposed revisions for QR in November and received QR feedback in December. The team is responding to the QR comments and has re-submitted PRC-019 to QR for posting. The team returned completed QR responses for MOD-027 on February 3 and will return the responses for MOD-025 on February 6. MOD-026 and PRC-024: The standards were posted for initial ballot June 15 - August 1, 2011. The team has met twice to develop responses to comments and develop revisions to the standards. The team submitted the proposed revisions for QR in November and received QR feedback in December. PRC-024

	026, MOD-024, PRC-019 **Last Update:** 2/6/12	was resubmitted to QR on 2/1/2012. The team returned completed QR responses for MOD-026 on February 3. A coordination issue with RFC standards MOD-024 and MOD-025 is being addressed. RFC is withholding filing of their MOD-024 and MOD-025 standards until the continent-wide standard MOD-025 is approved. They will then evaluate whether the continent-wide standard meets their needs.
Project 2010-07: Generator Requirements at the Transmission Interface **Description:** The proposed changes to the requirements and the addition of new requirements will add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid.	**Leadership:** Louis Slade (Dominion) **NERC Staff:** Mallory Huggins **SAR Date:** 1/15/10 **Team Assembly:** 6/16/10 **Target Finish:** 1/25/13 **Forecast Finish:** 7/20/12 **SPM Step:** Board Review **Related Standards:** PRC-004, FAC-001, FAC-003 **Last Update:** 2/6/12	**Status:** The SDT posted FAC-001-1, FAC-003-X, FAC-003-3, and PRC-004-2.1 for recirculation ballot on through December 23. At that time, the SDT also posted its consideration of comments form and an updated technical justification document. All four standards were approved by the industry with at least an 85% approval rating. NERC will present FAC-001-1 and PRC-004-2.1 for Board of Trustees adoption in February. FAC-003-3 will no longer be presented to the BOT pending a Level 1 Appeal submitted with respect to FAC-003-X/FAC-003-3. A nonbinding poll for VSLs and VRFs for FAC-001-1 (the only VSLs and VRFs that were substantively changed) was conducted from January 4-13, 2012 with a 91% approval rating. During its standard review, the SDT determined that PRC-005 also needs a slight change similar to the change made to PRC-004. The team will prepare those PRC-005 changes and post them for a concurrent comment and ballot period. Because differences remain with respect to the standards modified by the SDT and the standards cited in the NERC draft directive related to the gap at the generator interconnection Facility, the SDT held a meeting with NERC legal and compliance staff to faciliate some discussion on the issue. The SDT has not been persuaded that there is a technical justification for including additional standards within the scope of its work, and following the BOT presentation of FAC-003 (and any appeal-related work), the proposed changes to PRC-005, and updates to the technical justification document to incorporate the input of NERC technical experts, the SDT will consider its work complete.
Project 2010-INT-01 Interpretation of TOP-006-2 for FMPP **Description:** Florida Municipal Power Pool (FMPP) is seeking clarification as to whether the Balancing Authority is responsible for reporting generation resources available for use and the Transmission Operator is responsible for reporting transmission resources that are available for use. They are also seeking clarification as to whether “appropriate technical information concerning protective relays” refers to protective relays for which the entity has responsibility.	**Leadership:** **NERC Staff:** Edward Dobrowolski **SAR Date:** **Team Assembly:** **Target Finish:** **Forecast Finish:** 6/29/12 **SPM Step:** Quality Review **Related Standards:** TOP-006 **Last Update:** 2/6/12	**Status:** Approved by SC for Rapid Revision, Jan 12, 2012. SDT reviewed the interpretation process and revised TOP-006-2 to accommodate the requester's concerns. TOP-006-3 was submitted to QR on February 3, 2012.
Project 2011-INT-01 Interpretation of MOD-028 for Florida Power & Light Company **Description:** By using the words “on-peak”, “off-peak”, and “intra-day” this requirement implies there would have to be separate TTC numbers for different portions of the current day. However, R5 of MOD28 establishes the calculation frequencies and only requires an update to TTC once within the 7 days prior to the specified period where they are used in an ATC calculation. The clarification needed is on the ATC Drafting Team’s intent with respect to the quantity and timing of individual TTC calculations needed for use in the ATC calculations.	**Leadership:** **NERC Staff:** Andy Rodriquez **SAR Date:** **Team Assembly:** **Target Finish:** **Forecast Finish:** 4/6/12 **SPM Step:** Board Review **Related Standards:** MOD-028 **Last Update:** 1/26/12	**Status:** Rapid Revision Pilot Recirc Ballot completed. Quorum: 90.10%, Approval: 92.49%. Documents are being prepared for February Board of Trustees meeting.
Project 2011-INT-02 Interpretation of VAR-002 for Constellation Power Gen **Description:** Asks for clarification of whether a GOP must communicate to a TOP that a generator is in manual mode (no AVR) during start up or shut down.	**Leadership:** **NERC Staff:** Stephen Crutchfield **SAR Date:** **Team Assembly:** **Target Finish:** **Forecast Finish:** 6/29/12 **SPM Step:** Quality Review **Related Standards:** **Last Update:** 2/2/12	**Status:** Approved by SC for Rapid Revision, Jan 12, 2012. The drafting team held a conference call on January 19th to discuss the request and to propose revised language for the standard. The draft SAR and standard were submitted for QR on January 24. QR suggested an edit to the the revision that the team has accepted. The revised standard and mapping document were resubmitted to QR on 2/1/2012.

Priority: **High** (9)

Project 2007-02 Operating Personnel Communication Protocols **Description:** Requires developing new requirements in support of blackout recommendation #26 to ensure that real-time system operators use standard communication protocols during normal and emergency operations.	**Leadership:** Lloyd Snyder **NERC Staff:** Joseph Krisiak **SAR Date:** 3/1/07 **Team Assembly:** 9/9/11 **Target Finish:** 11/28/12 **Forecast Finish:** 2/13/13 **SPM Step:** Quality Review **Related Standards:** A_NEW_STANDARD **Last Update:** 2/6/12	**Status:** The SDT has agreed to the "All Call" definition and requirement language at its 1-24-12 meeting. The language was incorporated into the draft standard. During QR preparations a significant format change for the draft standard was proposed and presented to the team on 1-30-12 and 2-2-12. The SDT is generally supportive but the format has implications that the SDT wants to understand, discuss and resolve. A 2-6-12 meeting has been scheduled to resolve the issues. Target for QR approval is March 2012.
Project 2007-06 System Protection Coordination **Description:** Address applicability issues and upgrade existing requirements to remove ambiguity, and ensure that there is coordination of protection and control systems that connect more than one functional entity.	**Leadership:** Philip Winston, Southern Company **NERC Staff:** Al McMeekin **SAR Date:** 5/7/07 **Team Assembly:** 10/11/07 **Target Finish:** 1/21/13 **Forecast Finish:** 3/25/13 **SPM Step:** Standard Drafting **Related Standards:** PRC-001 **Last Update:** 2/6/12	**Status:** Al McMeekin and Phil Winston developed responses to the QR team's comments during the week of January 30, 2012. Many of the responses referenced the development of new requirements, measures, and VSLs. Phil Winson, with support from NERC staff, developed a new draft version of the standard and sent it to Bill Middaugh, Sam Francis, and Forrest Brock on Friday, February 3, 2012 for review. This small group plans to meet face to face in Dallas on February 7 & 8 in an effort to develop a viable first pass to send to the remainder of the team that same week. Phil and Al plan to meet @ NERC HQ in Atlanta February 13 & 14 to review team comments/suggestions and discuss progress with NERC staff. A Ready Talk meeting with the team will be held the week of 2/13. These efforts will hopefully minimize the amount of slippage in the schedule.
Project 2007-12 Frequency Response **Description:** Project 2007-12 Frequency Response and Frequency Bias - Develop a minimum Frequency Response needed for reliable operation and a consistent method for calculating the Frequency Bias Setting.	**Leadership:** Dave Lemmons - Excel - (Chair) Terry Bilke - MISO (Vice-chair) **NERC Staff:** Darrel Richardson **SAR Date:** 4/7/04 **Team Assembly:** 8/13/07 **Target Finish:** 5/29/12 **Forecast Finish:** 5/25/12 **SPM Step:** Analysis of Cmts or FT **Related Standards:** BAL-003 **Last Update:** 2/6/12	**Status:** The SDT received data from approximately 50 BAs. The SDT created sub-teams to provide an analysis of the data for the team to consider in the determination of FRM. The comment period and initiial ballot end on December 9, 2011. The Ballot failed. The SDT has responded to comments received from the comment/ballot period. The SDT received the QR comments on January 6, 2012. The SDT has conference calls to address QR comments set for: Monday January 6, 2012 1:00 p.m. - 5:00 p.m. ET Wednesday January 8, 2012 1:00 p.m. - 5:00 p.m. ET Friday January 10, 2012 10:00 a.m. - 2:00 p.m. ET The SDT also has face-to-face meetings set for the last two weeks of March to address comments received from the 3rd posting and second "initial" ballot.
Project 2007-17 Protection System Maintenance and Testing **Description:** Transmission and Generation Protection System Maintenance and Testing, to consolidate PRC-005-1, PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs; PRC-011-0 — UVLS System Maintenance and Testing; and PRC-017-0 — Special Protection System Maintenance and Testing into a single maintenance and testing standard. Standards PRC-008-0, PRC-011-0, and PRC-017-0 would then be withdrawn.	**Leadership:** Charles W. Rogers, Consumers Energy **NERC Staff:** Al McMeekin **SAR Date:** 5/7/07 **Team Assembly:** 10/11/07 **Target Finish:** 6/29/12 **Forecast Finish:** 6/29/12 **SPM Step:** Quality Review **Related Standards:** PRC-011, PRC-005, PRC-008, PRC-017 **Last Update:** 2/6/12	**Status:** The SDT met the week of January 23, 2012, and completed the response to comments and all modifications to the standard and associated documents resulting from the 45-day posting and initial ballot (August 15, 2011 - September 29, 2011.) Al McMeekin prepared the documents and forwarded them to Quality Review on Thursday, February 2, 2012. The standard is scheduled to be posted for a 30-day comment and successive ballot in early to mid-March, 2012. This schedule should be attainable, but it could be in jeopardy of slipping due to a FERC order issued Friday, February 3 directing NERC to include the maintenance of reclosing relays in this version of PRC-005-2. (It has been the SDT's and NERCs position that reclosing relays are not identified as specific components of the Protection System; and that reclosing relays are most often applied to improve system availability, as a convenience to accelerate system restoration, or both. Mal-performance of reclosing relays so applied has no detrimental effect on the reliability of the bulk power system.)
Project 2008-06 Cyber Security Order 706 **Description:** The second phase (Phase 2) of Project 2008-06 Cyber Security Order 706 will require the SDT to propose modifications not included in Phase 1 of the project to bring the following standards into conformance with the ERO Rules of Procedure and to address the directives from FERC Order 706: CIP-002-2 Critical Cyber Asset Identification CIP-003-2 Security Management Controls CIP-004-2 Personnel & Training CIP-005-2 Electronic Security Perimeter(s) CIP-006-2 Physical Security of Critical Cyber Assets CIP-007-2 Systems Security Management CIP-008-2 Incident Reporting and Response Planning CIP-009-2 Recovery Plans for Critical Cyber Assets	**Leadership:** John Lim (Consolidated Edison Co. of New York) Philip Huff (Arkansas Electric Cooperative Corporation) **NERC Staff:** Steven Noess **SAR Date:** 3/1/08 **Team Assembly:** 8/8/08 **Target Finish:** 7/25/12 **Forecast Finish:** 7/25/12 **SPM Step:** Successive Ballot **Related Standards:** CIP-011, CIP-002, CIP-010, CIP-003, CIP-004, CIP-005, CIP-006, CIP-007, CIP-008, CIP-009 **Last Update:** 2/6/12	**Status:** The SDT continues its work on developing version 5 of CIP-002 through CIP-011 in response to FERC Order 706. This team will also address items related to remote access vulnerabilities (transferred for the previous expedited project). The Version 5 CIP standards were posted for a 60 day formal comment period on November 7, 2011, with a 20 day parallel ballot ending January 6, 2012. All Ballots received over 90% quorums, and approvals were in the 20s and 30s for all ballots except the implementation plan, which was in the low 40s. The team is working on responding to significant, but constructive comments. They met in Taylor, TX from January 24-26, and they will meet again in Phoenix, AZ from February 21 through February 24, 2012. On schedule to submit documents to QR on February 27, 2012, and post for successive ballot at the end of March 2012. The project is slighly behind schedule because ballot and comment period was extended to 60 days (Jan 6, 2012), but the team is working to post for successive ballot during the first week of April 2012, which will put the project back on schedule.

☐	Project 2009-01 Disturbance and Sabotage Reporting **Description:** Project 2009-01 Disturbance and Sabotage Reporting - This project will entail revision to the following existing standards: •CIP-001-1 – Sabotage Reporting •EOP-004-1 – Disturbance Reporting Stakeholders have indicated that identifying potential acts of "sabotage" is difficult to do in real time, and additional clarity is needed to identify thresholds for reporting potential acts of sabotage in CIP-001-1. Stakeholders have also reported that EOP-004-1 has some requirements that reference out-of-date Department of Energy forms, making the requirements ambiguous. EOP-004-1 also has some 'fill-in-the-blank' components to eliminate. The project will include addressing previously identified stakeholder concerns and FERC directives; will bring the standards into conformance with the latest approved version of the ERO Rules of Procedure; and may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.	**Leadership:** Chair - Brian Evans-Mongeon (Util. Svcs.) Vice-Chair - Joseph DePoorter (MGE) **NERC Staff:** Stephen Crutchfield **SAR Date:** 4/2/09 **Team Assembly:** 11/12/09 **Target Finish:** 2/2/12 **Forecast Finish:** 8/8/12 **SPM Step:** Analysis of Cmts or FT **Related Standards:** EOP-004, CIP-001, CIP-008 **Last Update:** 2/6/12	**Status:** The proposed EOP-004-2 was posted for initial ballot October 28 December 12, 2011. The team received the comments on December 27th and held a conference call on January 5, 2012 to discuss the comments and propose a work plan. The team met January 25-27, 2012 and developed revised standard and preliminary responses to comments. The team will spend the next two weeks refining the response to comments and developing all of the associated documents to submit for QR. The team has a meeting scheduled with FERC staff on February 13 to ensure that there are no concerns from staff. The next posting will be for a 30-day comment period and successive ballot. The project schedule was updated on 2/2/2012 to add a successive ballot period and to revise the remaining tasks in the "Recirc Ballot", "BOT Approval" and "Filing" sections to match the project template.
☐	Project 2010-05.1 Phase 1 of Protection Systems: Misoperations **Description:** A key element for Bulk Electric System (BES) reliability is the correct performance of Protection Systems. Monitoring BES Protection System events, as well as identifying and correcting the root causes of Misoperations, will improve Protection System performance.	**Leadership:** Mark Kuras, PJM **NERC Staff:** Al McMeekin **SAR Date:** 6/9/11 **Team Assembly:** 6/22/11 **Target Finish:** 9/4/12 **Forecast Finish:** 9/4/12 **SPM Step:** Analysis of Cmts or FT **Related Standards:** PRC-004, PRC-004-WECC, PRC-003 **Last Update:** 2/6/12	**Status:** The team met January 10-12, 2012 to continue developing the draft standardand. The team continues to refine the requirements and consequently adjust the measures, VSLs, technical justification, as well as the responses to comments from the first posting. One issue that must be addressed by NERC and FERC staff regards the method of collecting Misoperations data. As of Sunday, February 5, NERC staff has not provided the team direction on this issue. The team meets this week beginning Tuesday, February 7th . This team is meeting twice in February to stay on track for delivering the documents to Quality Review in late March.
☐	Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves **Description:** Revise BAL-001-0.1a, BAL-002-1 and develop BAL-012-1 & BAL-013-1	**Leadership:** Larry Akens - TVA (Chair) Glenn Stephens - Santee Cooper (Vice-chair) **NERC Staff:** Darrel Richardson **SAR Date:** 5/3/07 **Team Assembly:** 12/11/07 **Target Finish:** 3/1/13 **Forecast Finish:** 5/2/13 **SPM Step:** Quality Review **Related Standards:** BAL-001, A_NEW_STANDARD, BAL-002 **Last Update:** 2/6/12	**Status:** The Standards have been received from Quality Review. The SDT has developed their responses to the Quality Review. The SDT will be sending their responses back to the Quality Review on February 7, 2012. The SDT will be scheduling meetings to address comments received from the first posting once the proposed standards are posted. The SDT will be trying to reduce the amount of time for review of the comments received from the first posting to make up the time delay encountered with the QR.
☐	Project 2010-17 Definition of BES - Part 2 **Description:** Revise the definition of Bulk Electric System (BES), including specific inclusions and exclusions, to address idnustry concerns identified but not resolved in the previous effort to meet the directives contained in FERC Orders 693 and 743.	**Leadership:** Pete Heidrich, FRCC = Chair Barry Lawson, NRECA = Vice Chair **NERC Staff:** Edward Dobrowolski **SAR Date:** 12/6/10 **Team Assembly:** 1/13/11 **Target Finish:** **Forecast Finish:** 2/6/12 **SPM Step:** Standard Drafting **Related Standards:** DEFINITION_ONLY, TBD **Last Update:** 2/6/12	**Status:** The team posted a draft SAR for stakeholder comment through February 3, 2012, and is reviewing the responses received.

16 Results

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Status of Interpretations

Andy Rodriquez will review the following information on the interpretations under active development.

Two Interpretations Awaiting Board Approval

- Project 2008-10 Interpretation of CIP-006-1 for Progress Energy.
- Project 2009-22 Interpretation of COM-002-2 for the IRC.

Two Interpretations in Current Development

- Project 2009-26 Interpretation of CIP-004-1 for WECC. Successive Ballot complete. (Quorum: 84.21% Approval: 42.24%). Team considering next steps.
- Project 2010-INT-05 CIP-002-1 for Duke Energy. Responding to comments received during first posting. The drafting team has reported to staff that it may not be possible to provide the requested clarity on one of the questions.

Seven Interpretations in Planning Queue

- Possible candidate for Rapid Revision: Project 2010-INT-03 Interpretation of TOP-002 for FMPP

Attachment 4bii

S - SC Interpretation Step (Multi-Row)

S - SC Interpretation Step (Multi-Row)

Edit Worksheet Delete Export Filter: S - Interpretations View: None Group: None

Name		
Status: **Current** (4)		
Priority: **High** (4)		
Project 2008-10 Interpretation of CIP-006-1 for Progress Energy **Description:** Progress Energy requests an interpretation as to the applicability of CIP-006-1 R1 to the aspects of the wiring that comprises the Electronic Security Perimeter (ESP). Does electronic security perimeter wiring external to a physical security perimeter have to be protected within a six-wall boundary?	**NERC Staff:** Steven Noess **Plan Finish:** 3/23/12 **Est. Finish:** 3/28/12 **SPM Step:** Board Review **Related Standards:** CIP-006 **Last Update:** 2/6/12	**Status:** Recirculation ballot approved. (Quorum: 88.02%, Approval: 96.04%). Interpretation submitted for consideration for approval to Board of Trustees during their February 9, 2012 meeting.
Project 2009-22 Interpretation of COM-002-2 for the IRC **Description:** The ISO/RTO Council is seeking clarification as to whether routine operating instructions are “directives” or whether “directives” are limited to actual and anticipated emergency operating conditions.	**NERC Staff:** Joseph Krisiak **Plan Finish:** 4/5/12 **Est. Finish:** 4/23/12 **SPM Step:** Board Review **Related Standards:** COM-002 **Last Update:** 2/6/12	**Status:** The interpretation was approved in a recirculation ballot by industry with a 94.58% approval. The interpretation is moving forward and will be presented to the BOT at their Phoenix meeting on 2/9.
Project 2009-26 Interpretation of CIP-004-1 for WECC **Description:** "WECC is seeking clarification on the definition of “authorized access” as applied to temporary support from vendors. Do the training, risk assessment and access requirements specified in R2, R3, and R4 apply to vendors who are supervised? Assuming that a “supervised” vendor is exempt from CIP-004-1, Requirements R2, R3 and R4, would temporary, indirect and monitored access such as that provided through remote terminal sessions (WebEx, etc.) or escorted physical access be considered supervision? "	**NERC Staff:** Steven Noess **Plan Finish:** 5/2/12 **Est. Finish:** 8/8/12 **SPM Step:** Quality Review **Related Standards:** CIP-004 **Last Update:** 2/6/12	**Status:** The initial ballot for an interpretation of standard CIP-004-1 — Cyber Security — Personnel & Training, Requirements R2, R3, and R4, for WECC ended on January 19, 2010, and failed (Quorum: 84.21% Approval: 42.24%). Since at least one negative ballot included a comment, the results are not final. The Interpretation Drafting Team has reviewed and responded to all comments from the initial posting, and they have revised the interpretation for successive ballot. The interpretation will be posted for successive ballot on Tuesday, February 7, 2012.
Project 2010-INT-05 CIP-002-1 for Duke Energy **Description:** Duke Energy is seeking clarification on the phrase "Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange" and what the phrase "essential to the operation of the Critical Asset" means.	**NERC Staff:** Steven Noess **Plan Finish:** 9/26/12 **Est. Finish:** 11/2/12 **SPM Step:** Initial Ballot **Related Standards:** CIP-002 **Last Update:** 2/6/12	**Status:** The Interpretation Drafting Team has reviewed the comments from the first formal posting. In response, they have responded to the comments and have prepared the interpretation for initial ballot. Interpretation will be posted for formal comment and initial ballot on February 7, 2012.
Status: **Planning** (7)		
Priority: **Normal** (4)		
Project 2010-INT-03 TOP-002-2a for FMPP **Description:** Florida Municipal Power Pool (FMPP) is	**NERC Staff:**	**Status:** Possible candidate for Rapid Revision.

	seeking clarification as to what "ensure" and "deliverability/ capability" mean and whether the Balancing Authority needs to maintain accurate computer models to analyze and plan to maintain a load-interchange-generation balance.	**Plan Finish:** 3/23/11 **Est. Finish:** 3/23/11 **SPM Step:** Completed **Related Standards:** **Last Update:** 2/6/12	
☐	TBD RFI received on 06/09/2011 from Consumers Energy on CIP-003 **Description:** Clarification needed: Applicability Section 4.1 regarding multiple functions and on R2 regarding can a Registered Entity assign different CIP Senior Managers for different applicable functions for which it is registered?	**NERC Staff:** Steven Noess **Plan Finish:** 9/1/11 **Est. Finish:** 9/1/11 **SPM Step:** New **Related Standards:** **Last Update:** 11/1/11	**Status:** Assigned to CIP IDT, to be processed when earlier requests have been moved through the process.
☐	TBD RFI received on 7/22/11 from EEI and NRECA on CIP-001-1 **Description:** Asks for clarification that the term 'facilities' includes only those facilities necessary for operating an interconnected electric energy transmission network and generation facilities needed to maintain transmission system reliability.	**NERC Staff:** **Plan Finish:** 11/1/11 **Est. Finish:** 11/1/11 **SPM Step:** New **Related Standards:** CIP-001 **Last Update:** 11/1/11	**Status:** In August the SC voted to move forward with this interpretation. Drafting team appointment on hold pending finalization of CAN-0016 to see if the revision of the CAN provides clarification. In September, the SC reaffirmed this decision. In October, EEI indicated their intent (in policy input to the Board of Trustees) to pursue an appeal of CAN-0016.
☐	TBD RFI Received Jan 25, 2013 from AEP on CIP-005 **Description:** Ask for clarification whether for the purposes of access point identification, "externally connected communications endpoints" include those communications links that do not use either (1) a routable protocol (such as IP), or (2) a dial-up modem.	**NERC Staff:** Steven Noess **Plan Finish:** 2/6/12 **Est. Finish:** 2/6/12 **SPM Step:** New **Related Standards:** CIP-005 **Last Update:** 2/6/12	**Status:**
Priority: **High** (3)			
☐	TBD RFI received on 11/4/2010 from TECO on CIP-007 **Description:** Asks if procedural controls are an acceptable method of complying with R5.3 when enforcement cannot be achieved through technical means, or if BOTH technical and procedural controls must be implemented in every instance	**NERC Staff:** Steven Noess **Plan Finish:** 3/23/11 **Est. Finish:** 3/23/11 **SPM Step:** New **Related Standards:** CIP-007 **Last Update:** 11/1/11	**Status:** Requester has indicated that he would like to move forward with the request, pending the outcome of revisions to CAN.
☐	TBD RFI received on 12/28/2010 from ITC on CIP-007 **Description:** Asks for clarity on passwords – specifically looking for more clarity on 'technical controls' and 'procedural controls' as they apply to passwords – and clarity on when/if the requirement is to have both technical and procedural controls	**NERC Staff:** Steven Noess **Plan Finish:** 3/23/11 **Est. Finish:** 3/23/11 **SPM Step:** New **Related Standards:** CIP-007 **Last Update:** 11/1/11	**Status:** Assigned to CIP IDT, to be processed when earlier requests have been moved through the process.
☐	TBD RFI received on 2/24/2011 from OGE on CIP-002-3 R1.2.5 **Description:** Asks for clarification about applicability of CIP-002 to AMI systems.	**NERC Staff:** Steven Noess **Plan Finish:** 4/26/11 **Est. Finish:** 4/26/11 **SPM Step:** New **Related Standards:** CIP-002 **Last Update:** 11/1/11	**Status:** Assigned to CIP IDT, to be processed when earlier requests have been moved through the process.

11 Results

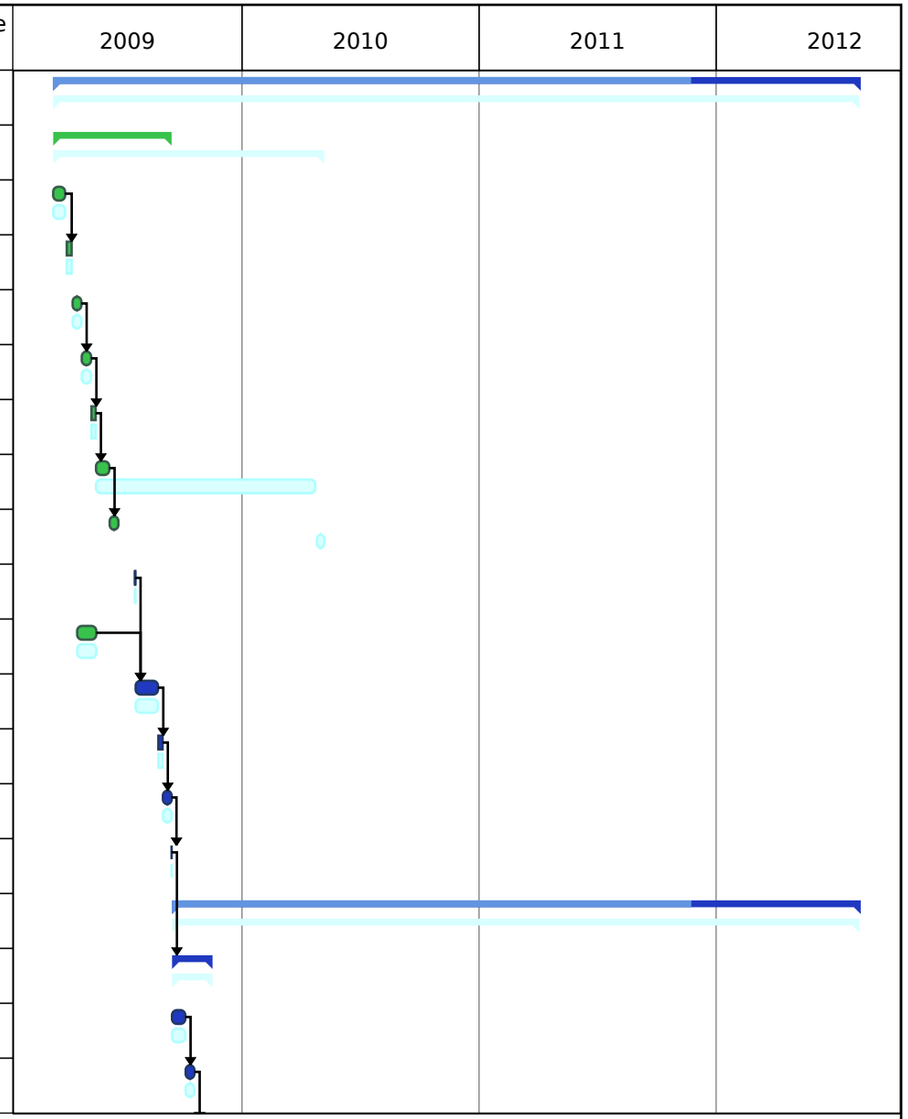
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Project 2009-01 – Disturbance and Sabotage Reporting Schedule Revision

Background:
EOP-004-2 – Event Reporting was posted for a parallel comment and initial ballot period that ended December 11, 2011. The standard received only a 36% weighted segment approval, necessitating the addition of a successive ballot. The SDT has developed an updated project plan to reflect the addition of a successive ballot.

Request:
Endorse the revised project schedule for Project 2009-01.

#	Name	%	Start Date	Completion Date
1	**Project 2009-01 Disturbance and Sabotage Reporting**	79.0 %	3/16/09 9:00 AM	8/10/12 5:00 PM
2	**SAR Development and Finalization**	100. 0%	3/16/09 9:00 AM	9/14/09 5:00 PM
3	Draft SAR	100. 0%	3/16/09 9:00 AM	4/3/09 5:00 PM
4	Submit SAR to Standards Committee	100. 0%	4/6/09 9:00 AM	4/13/09 5:00 PM
5	Standards Committee Accepts SAR	100. 0%	4/15/09 8:00 AM	4/28/09 5:00 PM
6	Post Request for SAR DT Nominations	100. 0%	4/29/09 9:00 AM	5/13/09 5:00 PM
7	Develop SAR DT Recommendation	100. 0%	5/14/09 9:00 AM	5/20/09 5:00 PM
8	Provide SAR DT Recommendation to SC	100. 0%	5/21/09 9:00 AM	6/10/09 5:00 PM
9	SC Appoints SAR DT	100. 0%	6/11/09 9:00 AM	6/24/09 5:00 PM
10	Hold Pre-project Meeting with SAR DT Leaders	100. 0%	7/20/09 9:00 AM	7/20/09 5:00 PM
11	Post SAR for Comment	100. 0%	4/22/09 8:00 AM	5/21/09 5:00 PM
12	Address Comments Received on SAR Posting	100. 0%	7/21/09 9:00 AM	8/24/09 5:00 PM
13	Submit SAR to SC for Approval	100. 0%	8/25/09 9:00 AM	8/31/09 5:00 PM
14	Receive Authorization to Proceed by SC	100. 0%	9/1/09 9:00 AM	9/14/09 5:00 PM
15	Project Moved to Standard Development Phase	100. 0%	9/14/09 5:00 PM	9/14/09 5:00 PM
16	**Standard Development**	75.4 %	9/15/09 9:00 AM	8/10/12 5:00 PM
17	**Appoint Standard Drafting Team**	100. 0%	9/15/09 9:00 AM	11/16/09 5:00 PM
18	Post Request for SDT Nominations	100. 0%	9/15/09 9:00 AM	10/5/09 5:00 PM
19	Develop SDT Recommendation	100. 0%	10/6/09 9:00 AM	10/19/09 5:00 PM



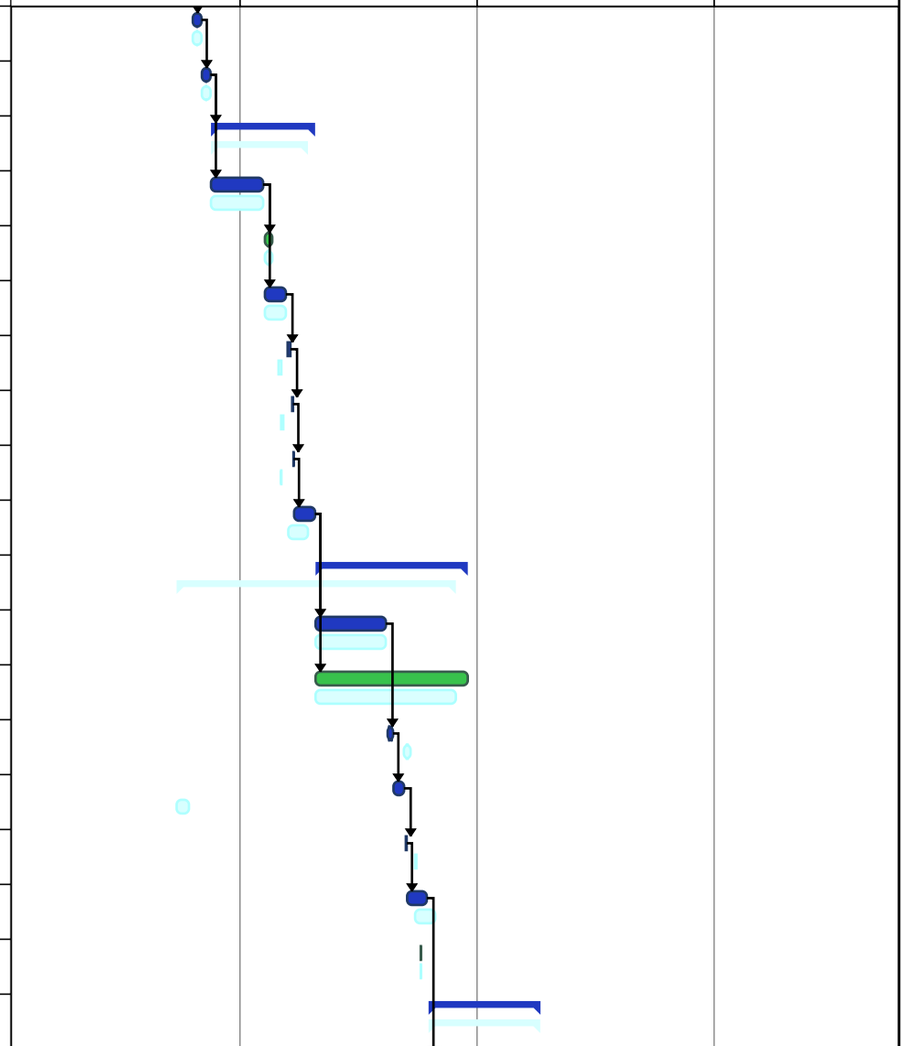
Project: Project 2009-01 Disturbance and Sabotage Reporting
Planned Start: 3/16/09
Projected Start: 3/16/09
Planned Completion: 8/10/12
Projected Completion: 8/8/12
Printed On: 2/6/12

Project 2009-01 Disturbance and Sabotage Reporting - This project will entail revision to the following existing standards:
•CIP-001-1 – Sabotage Reporting
•EOP-004-1 – Disturbance Reporting
Stakeholders have indicated that identifying potential acts of "sabotage" is difficult to do in real time, and additional clarity is

Planned
Overdue
In Progress
Complete
Predecessor
Projected
Critical Path
Summary
Milestone

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#	Name	%	Start Date	Completion Date
20	Provide SDT Recommendation TO SC	100.0%	10/20/09 9:00 AM	11/2/09 5:00 PM
21	SC Appoints Standard Drafting Team	100.0%	11/3/09 9:00 AM	11/16/09 5:00 PM
22	**Develop Concepts Paper**	100.0%	11/17/09 9:00 AM	4/26/10 5:00 PM
23	Hold Pre-project Meeting with SDT Leaders	100.0%	11/17/09 9:00 AM	2/5/10 5:00 PM
24	Educate SDT on Project Expectations and Parameters	100.0%	2/8/10 9:00 AM	2/19/10 5:00 PM
25	Develop Concepts paper	100.0%	2/8/10 9:00 AM	3/12/10 5:00 PM
26	Submit Draft Documents for NERC Staff Review	100.0%	3/15/10 9:00 AM	3/19/10 5:00 PM
27	Revise Documents Based on NERC Staff Review	100.0%	3/22/10 9:00 AM	3/23/10 5:00 PM
28	Re-submit Draft Documents for NERC Staff Review	100.0%	3/24/10 9:00 AM	3/24/10 5:00 PM
29	Informal Posting of Concepts paper Industry Comment	100.0%	3/25/10 9:00 AM	4/26/10 5:00 PM
30	**Develop Initial Draft of Standard(s)**	100.0%	4/27/10 9:00 AM	12/17/10 5:00 PM
31	Develop Initial Draft of Standard	100.0%	4/27/10 9:00 AM	8/13/10 5:00 PM
32	Seek Regulatory Clarification on Directives/Other	100.0%	4/27/10 9:00 AM	12/17/10 5:00 PM
33	Submit Draft Documents for Quality Review	100.0%	8/16/10 9:00 AM	8/24/10 5:00 PM
34	Revise Documents Based on Quality Review	100.0%	8/25/10 9:00 AM	9/10/10 5:00 PM
35	Re-submit Draft Documents for Quality Review	100.0%	9/13/10 9:00 AM	9/14/10 5:00 PM
36	Initial Posting of Documents for Industry Comment	100.0%	9/15/10 9:00 AM	10/15/10 5:00 PM
37	Industry Webinar on Proposed Standard(s)/Modification(s) at Standards workshop.	100.0%	10/6/10 9:00 AM	10/6/10 5:00 PM
38	**Develop Second Draft of Standard(s)**	100.0%	10/18/10 9:00 AM	4/8/11 5:00 PM



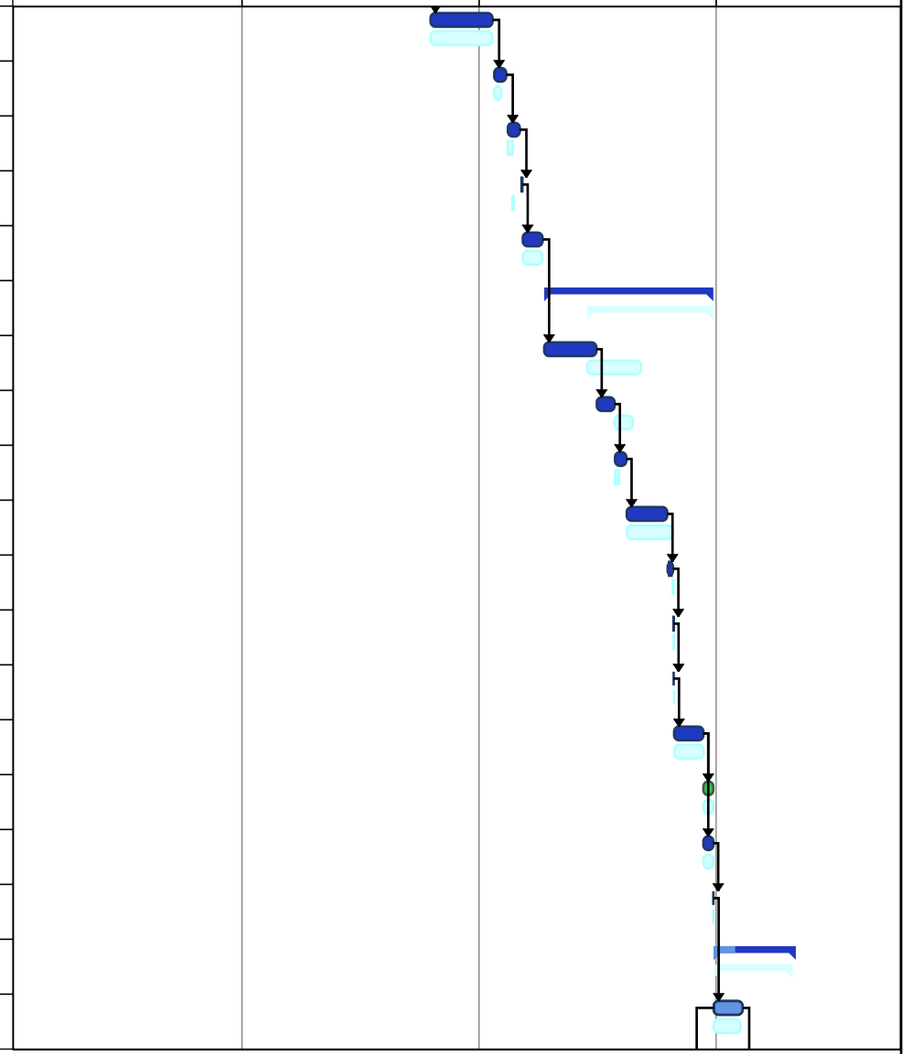
Project: Project 2009-01 Disturbance and Sabotage Reporting
Planned Start: 3/16/09
Projected Start: 3/16/09
Planned Completion: 8/10/12
Projected Completion: 8/8/12
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#	Name	%	Start Date	Completion Date
39	Develop Reply Comments and Second Draft of Standard	100.0%	10/18/10 9:00 AM	1/21/11 5:00 PM
40	Submit Draft Documents for Quality Review	100.0%	1/24/11 9:00 AM	2/11/11 5:00 PM
41	Revise Documents Based on Quality Review	100.0%	2/14/11 9:00 AM	3/4/11 5:00 PM
42	Re-submit Draft Documents for Quality Review	100.0%	3/7/11 9:00 AM	3/8/11 5:00 PM
43	Second Posting of Documents for Industry Comment	100.0%	3/9/11 9:00 AM	4/8/11 5:00 PM
44	**Initial Ballot**	100.0%	4/11/11 9:00 AM	12/27/11 5:00 PM
45	Develop Reply Comments and finalize standard	100.0%	4/11/11 9:00 AM	6/30/11 5:00 PM
46	Submit Draft Documents for Quality Review	100.0%	7/1/11 9:00 AM	7/28/11 5:00 PM
47	Revise Documents Based on QualityReview	100.0%	7/29/11 9:00 AM	8/15/11 5:00 PM
48	Re-submit Draft Documents for Quality Review	100.0%	8/16/11 9:00 AM	10/17/11 5:00 PM
49	Seek SC Approval to move to Ballot	100.0%	10/18/11 9:00 AM	10/26/11 5:00 PM
50	Receive SC Approval to Move to Ballot	100.0%	10/27/11 9:00 AM	10/27/11 5:00 PM
51	Project Moved to Balloting Phase	100.0%	10/27/11 5:00 PM	10/27/11 5:00 PM
52	45-Day Pre-ballot Review and Initial Ballot	100.0%	10/28/11 9:00 AM	12/12/11 9:00 AM
53	Assemble Comments on Draft Standard and Send to Project Manager	100.0%	12/12/11 9:00 AM	12/27/11 5:00 PM
54	Assemble Ballot Comments on Draft Standard and Send to Project Manager	100.0%	12/12/11 9:00 AM	12/27/11 5:00 PM
55	Initial Ballot Complete	100.0%	12/27/11 5:00 PM	12/27/11 5:00 PM
56	**F - SUCCESSIVE BALLOT**	26.1%	12/28/11 9:00 AM	5/2/12 5:00 PM
57	Respond to Comments Received	95.0%	12/28/11 9:00 AM	2/10/12 5:00 PM



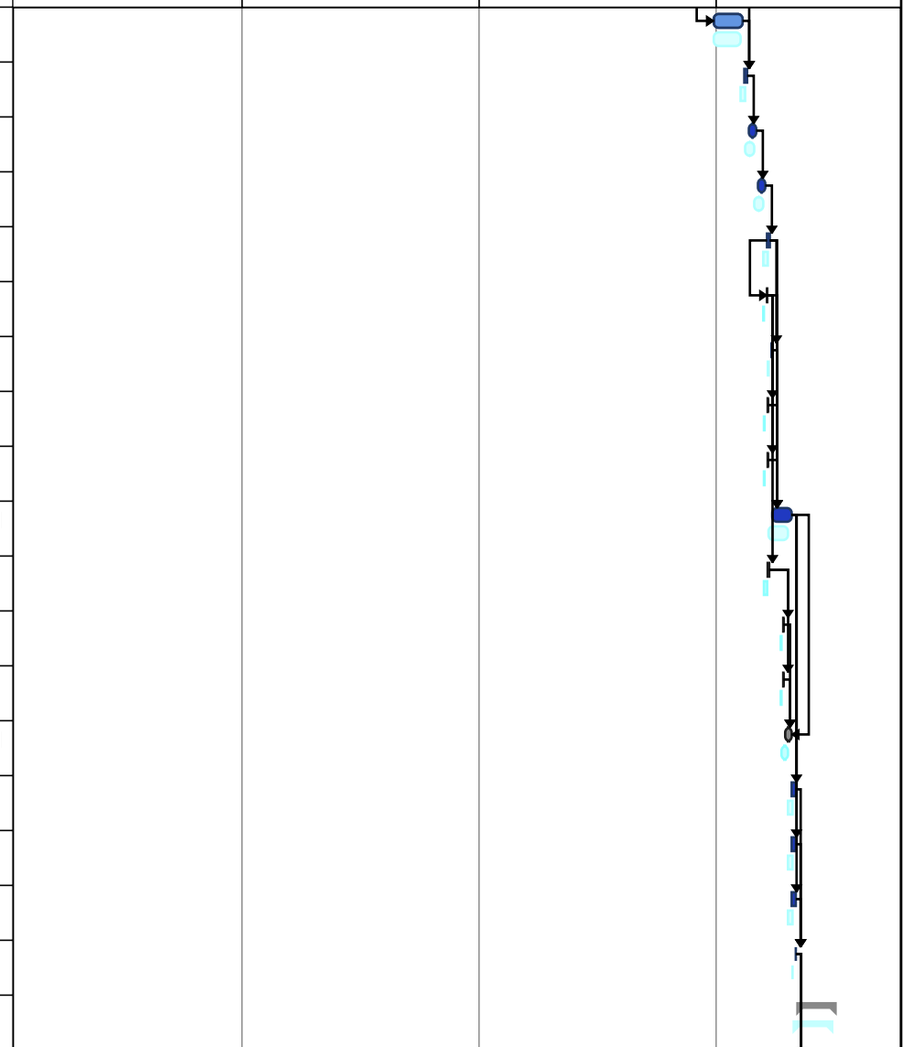
Project: Project 2009-01 Disturbance and Sabotage Reporting
Planned Start: 3/16/09 Projected Start: 3/16/09
Planned Completion: 8/10/12 Projected Completion: 8/8/12
Printed On: 2/6/12

Project 2009-01 Disturbance and Sabotage Reporting - This project will entail revision to the following existing standards:
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#	Name	%	Start Date	Completion Date
58	Write Draft Standard	95.0 %	12/28/11 9:00 AM	2/10/12 5:00 PM
59	Send Posting Package to SPM for Quality Review	0.0 %	2/13/12 9:00 AM	2/17/12 5:00 PM
60	Perform Quality Review of Posting Package	0.0 %	2/20/12 9:00 AM	3/2/12 5:00 PM
61	Edit Posting Package based on QR and Send to SPM	0.0 %	3/5/12 9:00 AM	3/16/12 5:00 PM
62	Final Pre-Posting Review of Posting Package	0.0 %	3/19/12 9:00 AM	3/23/12 5:00 PM
63	Write Draft Standard Posting Announcement	0.0 %	3/19/12 9:00 AM	3/19/12 5:00 PM
64	Post Draft Standard and Update Web Page	0.0 %	3/26/12 9:00 AM	3/26/12 5:00 PM
65	Post Draft Standard Posting Announcement	0.0 %	3/20/12 9:00 AM	3/20/12 5:00 PM
66	Distribute Draft Standard Posting Announcement	0.0 %	3/20/12 9:00 AM	3/20/12 5:00 PM
67	Comment Period	0.0 %	3/27/12 9:00 AM	4/26/12 9:00 AM
68	Write Successive Ballot Announcement	0.0 %	3/20/12 9:00 AM	3/22/12 5:00 PM
69	Post Successive Ballot Announcement	0.0 %	4/13/12 9:00 AM	4/13/12 5:00 PM
70	Distribute Successive Ballot Announcement	0.0 %	4/13/12 9:00 AM	4/13/12 5:00 PM
71	Conduct Successive Ballot over 10 days	0.0 %	4/16/12 9:00 AM	4/26/12 9:00 AM
72	Assemble Comments on Draft Standard and Send to Project Manager	0.0 %	4/26/12 9:00 AM	5/2/12 5:00 PM
73	Assemble Ballot Comments on Draft Standard and Send to Project Manager	0.0 %	4/26/12 9:00 AM	5/2/12 5:00 PM
74	Assemble Ballot Results and Update Web Page	0.0 %	4/26/12 9:00 AM	5/2/12 5:00 PM
75	Successive Ballot Complete	0.0 %	5/2/12 5:00 PM	5/2/12 5:00 PM
76	**G - RECIRC BALLOT**	0.0 %	5/3/12 9:00 AM	7/4/12 5:00 PM



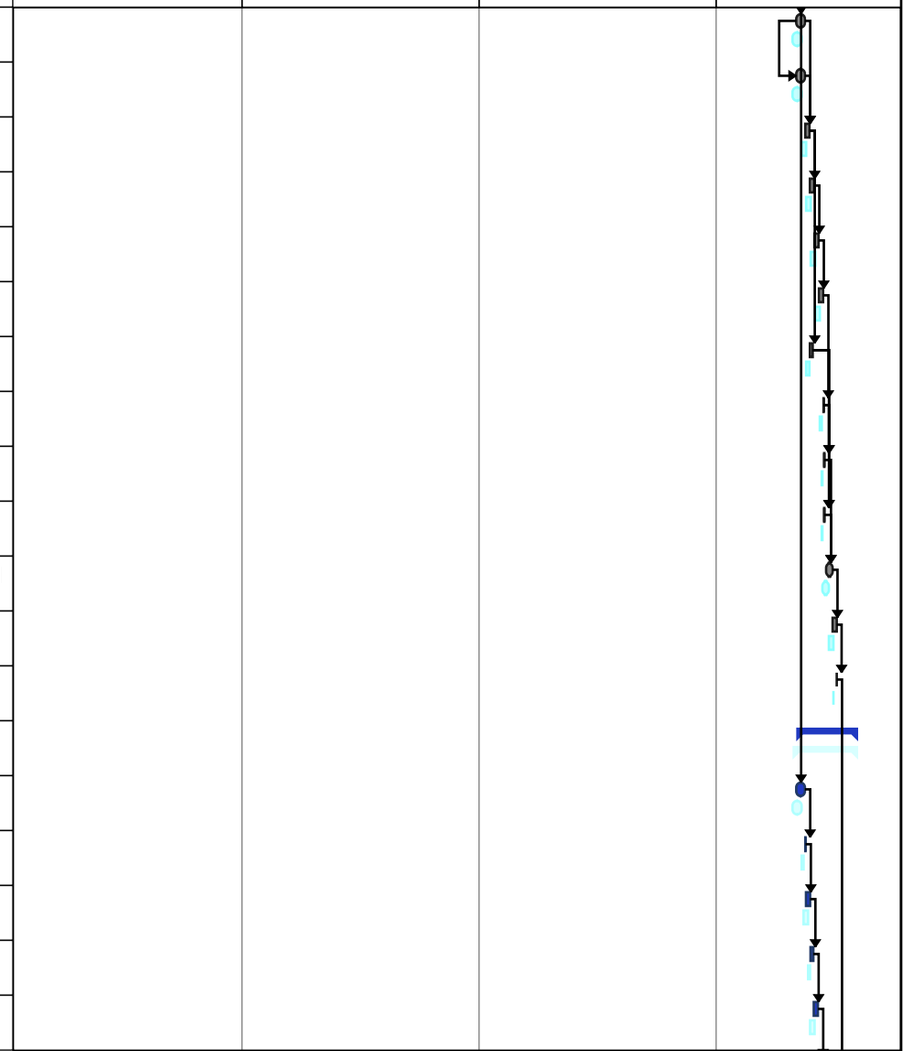
Project: Project 2009-01 Disturbance and Sabotage Reporting
Planned Start: 3/16/09 Projected Start: 3/16/09
Planned Completion: 8/10/12 Projected Completion: 8/8/12
Printed On: 2/6/12

Project 2009-01 Disturbance and Sabotage Reporting - This project will entail revision to the following existing standards:
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#	Name	%	Start Date	Completion Date
77	Respond to Comments Received	0.0 %	5/3/12 9:00 AM	5/16/12 5:00 PM
78	Write Draft of Standard	0.0 %	5/3/12 9:00 AM	5/16/12 5:00 PM
79	Send Posting Package to SPM for Quality Review	0.0 %	5/17/12 9:00 AM	5/23/12 5:00 PM
80	Perform Quality Review of Posting Package	0.0 %	5/24/12 9:00 AM	5/30/12 5:00 PM
81	Edit Posting Package based on QR and Send to SPM	0.0 %	5/31/12 9:00 AM	6/6/12 5:00 PM
82	Final Pre-Posting Review of Posting Package	0.0 %	6/7/12 9:00 AM	6/13/12 5:00 PM
83	Write Recirculation Ballot Announcement	0.0 %	5/24/12 9:00 AM	5/28/12 5:00 PM
84	Post Draft Standard and Update Web Page	0.0 %	6/14/12 9:00 AM	6/14/12 5:00 PM
85	Post Recirculation Ballot Announcement	0.0 %	6/15/12 9:00 AM	6/15/12 5:00 PM
86	Distribute Recirculation Ballot Announcement	0.0 %	6/15/12 9:00 AM	6/15/12 5:00 PM
87	Conduct Recirculation Ballot over 10 days	0.0 %	6/18/12 9:00 AM	6/28/12 9:00 AM
88	Assemble Ballot Results and Update Web Page	0.0 %	6/28/12 9:00 AM	7/4/12 5:00 PM
89	Recirc Complete	0.0 %	7/4/12 5:00 PM	7/4/12 5:00 PM
90	**H - BOT APPROVAL**	0.0 %	5/3/12 9:00 AM	8/6/12 4:00 PM
91	Develop Board Materials	0.0 %	5/3/12 9:00 AM	5/16/12 5:00 PM
92	Send Board Materials to Standards Leadership	0.0 %	5/17/12 9:00 AM	5/17/12 5:00 PM
93	Perform Standards Leadership Review	0.0 %	5/18/12 9:00 AM	5/24/12 5:00 PM
94	Edit Board Materials based on Leadership Review	0.0 %	5/25/12 9:00 AM	5/29/12 5:00 PM
95	Perform Legal Review	0.0 %	5/30/12 9:00 AM	6/5/12 5:00 PM



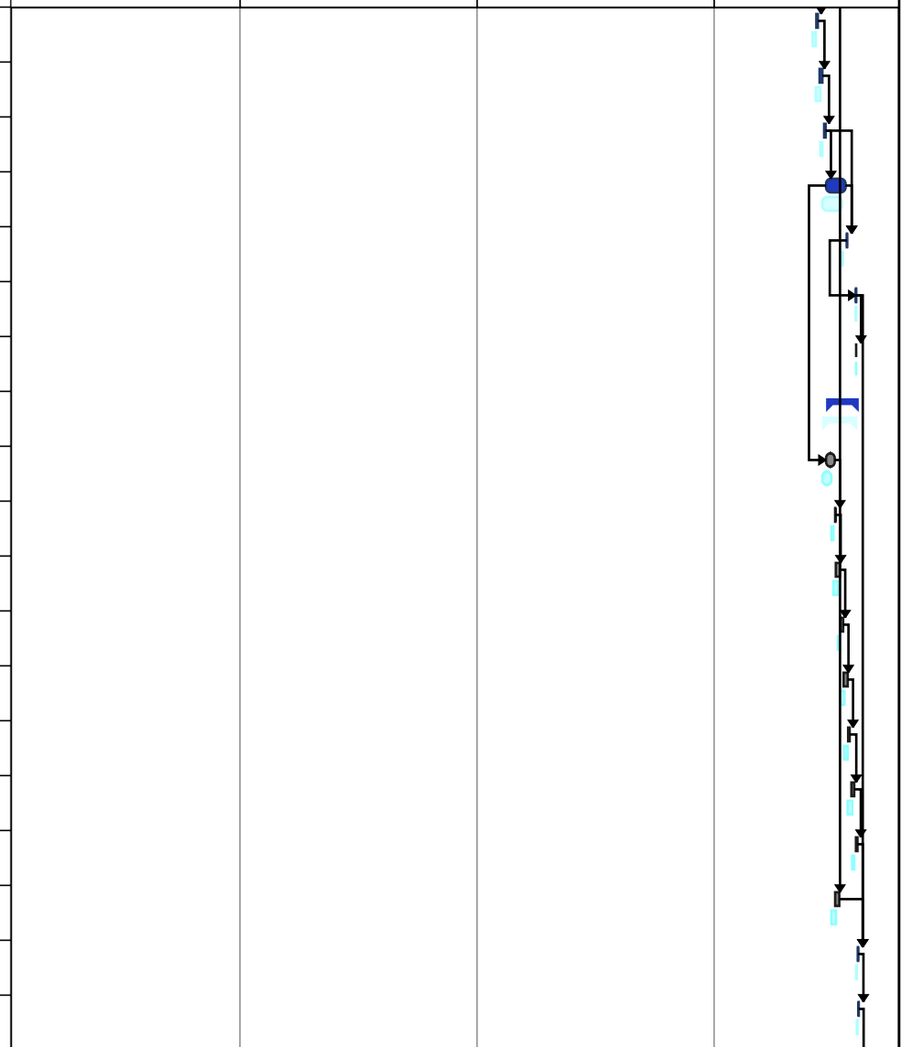
Project: Project 2009-01 Disturbance and Sabotage Reporting
Planned Start: 3/16/09
Projected Start: 3/16/09
Planned Completion: 8/10/12
Projected Completion: 8/8/12
Printed On: 2/6/12

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Stakeholders have indicated that identifying potential acts of "sabotage" is difficult to do in real time, and additional clarity is

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Predecessor
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Critical Path
Summary
Milestone

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#	Name	%	Start Date	Completion Date
96	Edit Board Materials based on Legal Review and send to Exec Mgmt	0.0 %	6/6/12 9:00 AM	6/8/12 5:00 PM
97	Perform Exec Mgmt Review	0.0 %	6/11/12 9:00 AM	6/15/12 5:00 PM
98	Edit Board Materials based on Exec Mgmt Review	0.0 %	6/18/12 9:00 AM	6/20/12 5:00 PM
99	Submit Board Materials to Board	0.0 %	6/21/12 9:00 AM	7/21/12 9:00 AM
100	Present Board Materials to Board	0.0 %	7/23/12 9:00 AM	7/23/12 5:00 PM
101	Board Vote on Materials	0.0 %	8/6/12 8:00 AM	8/6/12 4:00 PM
102	BOT Approval Complete	0.0 %	8/6/12 4:00 PM	8/6/12 4:00 PM
103	**I - FILING**	0.0 %	6/21/12 9:00 AM	8/10/12 5:00 PM
104	Develop Draft Filing	0.0 %	6/21/12 9:00 AM	7/4/12 5:00 PM
105	Send Draft Filing to Standard Regulatory Initiatives	0.0 %	7/5/12 9:00 AM	7/5/12 5:00 PM
106	Perform Standards Regulatory Initiatives Review	0.0 %	7/6/12 9:00 AM	7/12/12 5:00 PM
107	Edit Draft Filing based on SRI Review and send to Legal	0.0 %	7/13/12 9:00 AM	7/17/12 5:00 PM
108	Perform Legal Review	0.0 %	7/18/12 9:00 AM	7/24/12 5:00 PM
109	Edit Draft Filing based on Legal Review and send to Exec Mgmt	0.0 %	7/25/12 9:00 AM	7/27/12 5:00 PM
110	Perform Exec Mgmt Review	0.0 %	7/30/12 9:00 AM	8/3/12 5:00 PM
111	Edit Draft Filing based on Exec Mgmt Review	0.0 %	8/6/12 9:00 AM	8/8/12 5:00 PM
112	Assemble development record	0.0 %	7/5/12 9:00 AM	7/11/12 5:00 PM
113	Assemble Final Filing Package	0.0 %	8/9/12 9:00 AM	8/9/12 5:00 PM
114	Submit Final Filing Package	0.0 %	8/10/12 9:00 AM	8/10/12 5:00 PM



Project: Project 2009-01 Disturbance and Sabotage Reporting
Planned Start: 3/16/09 Projected Start: 3/16/09
Planned Completion: 8/10/12 Projected Completion: 8/8/12
Printed On: 2/6/12

Project 2009-01 Disturbance and Sabotage Reporting - This project will entail revision to the following existing standards:
•CIP-001-1 – Sabotage Reporting
•EOP-004-1 – Disturbance Reporting
Stakeholders have indicated that identifying potential acts of "sabotage" is difficult to do in real time, and additional clarity is

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Overdue
In Progress
Complete
Predecessor
Projected
Critical Path
Summary
Milestone

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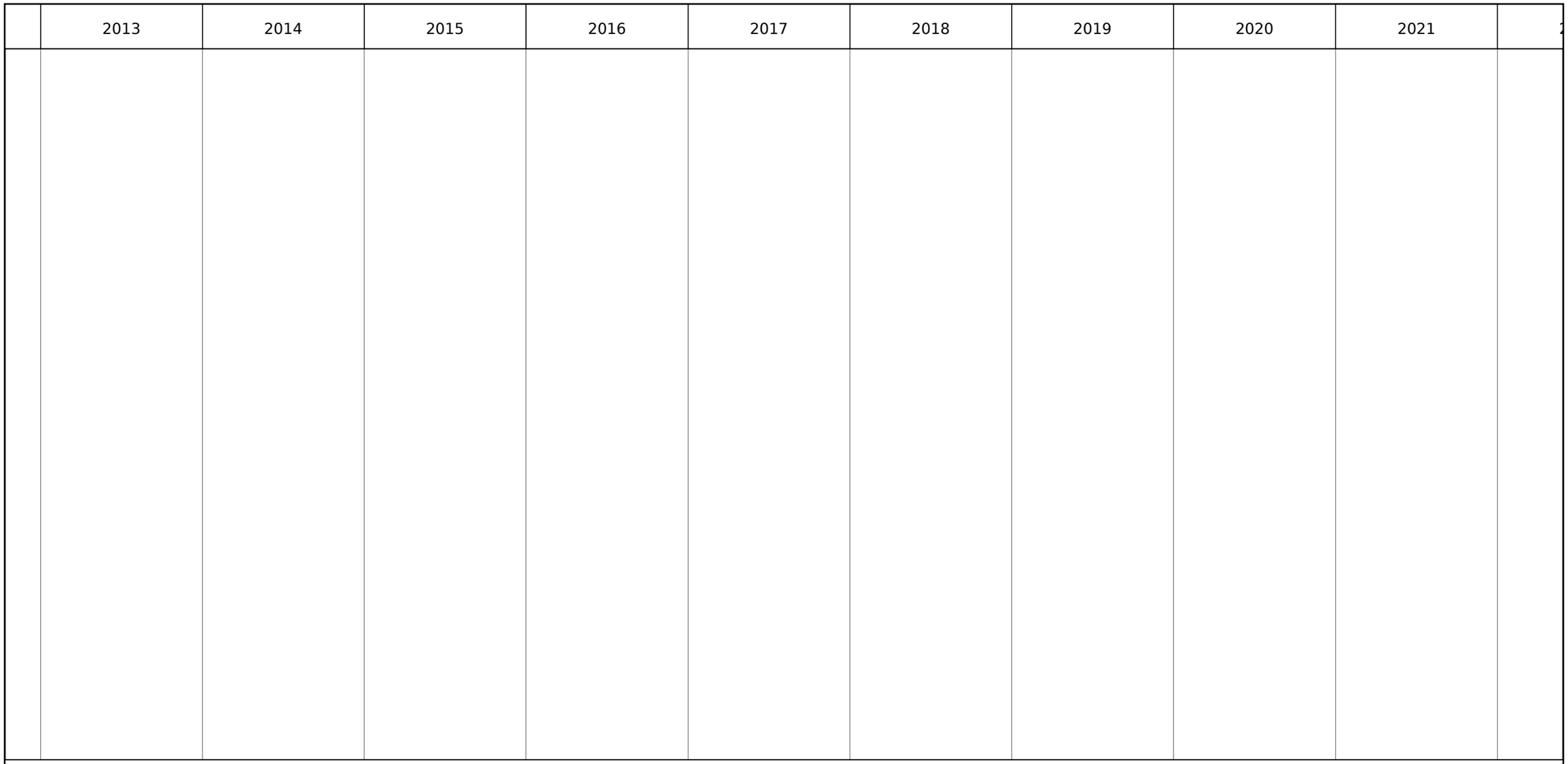
#	Name	%	Start Date	Completion Date	2009	2010	2011	2012
115	Filing Complete	0.0 %	8/10/12 5:00 PM	8/10/12 5:00 PM				

Project: Project 2009-01 Disturbance and Sabotage Reporting
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Projected Start: 3/16/09
Planned Completion: 8/10/12
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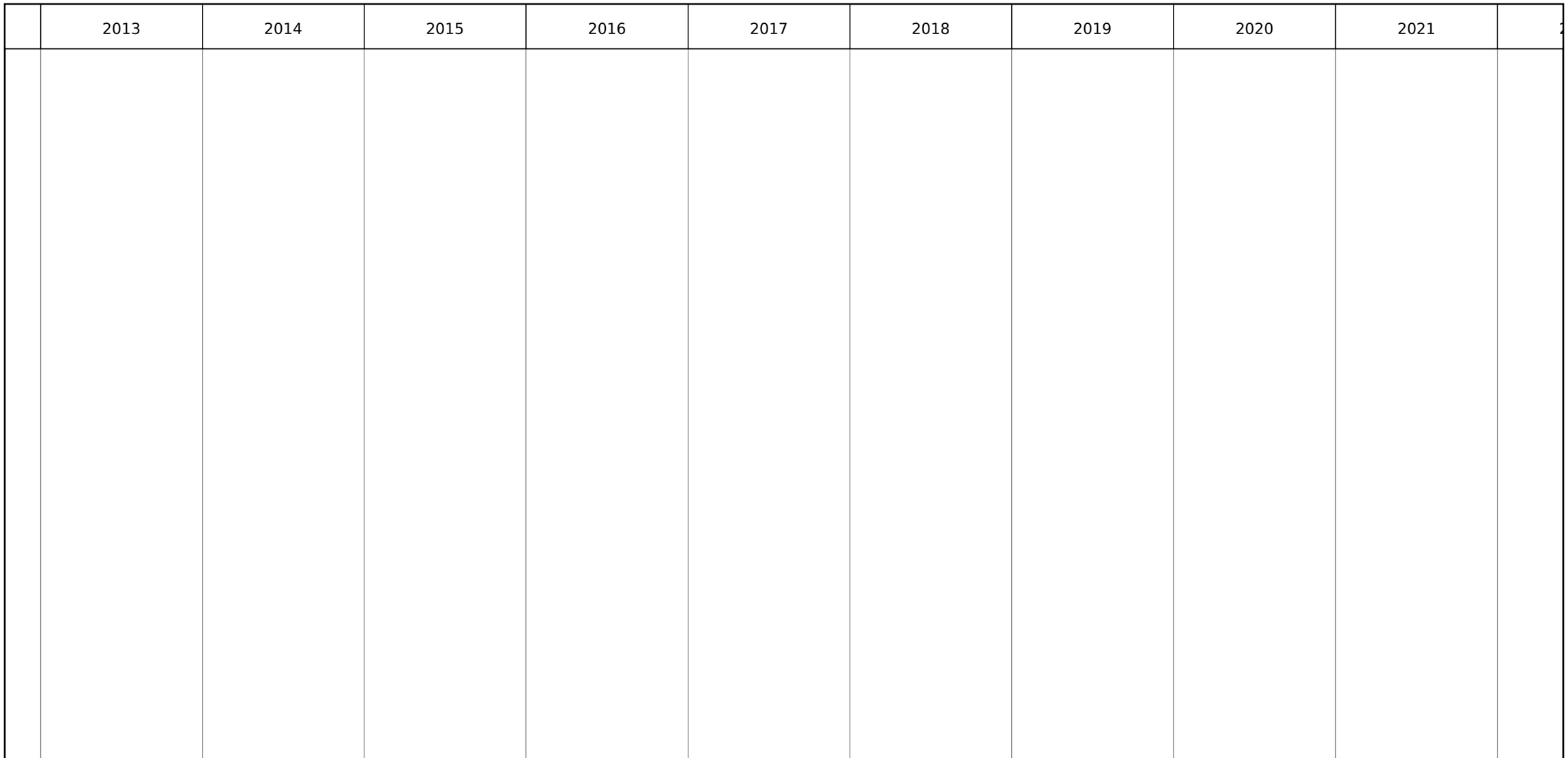


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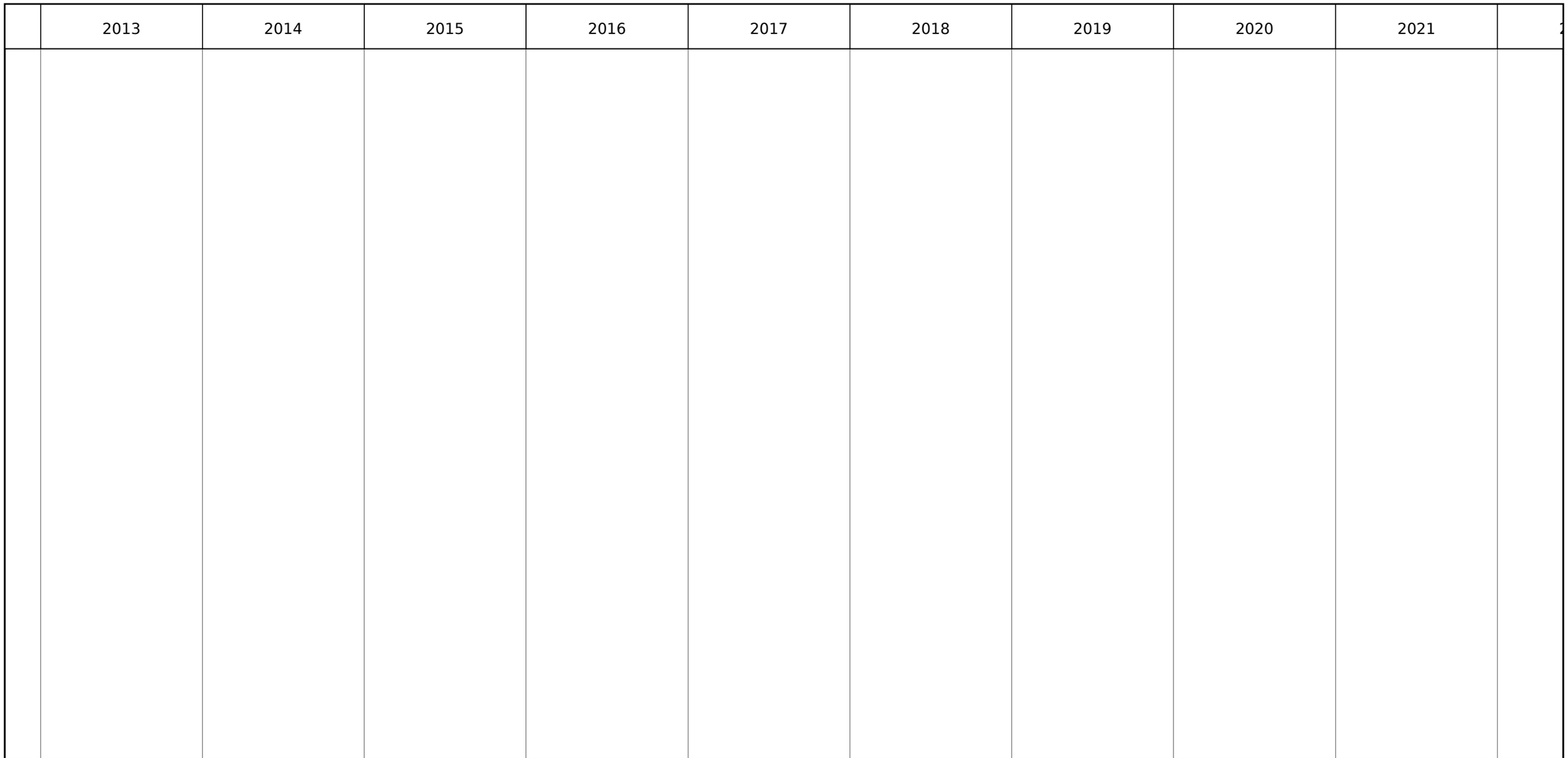


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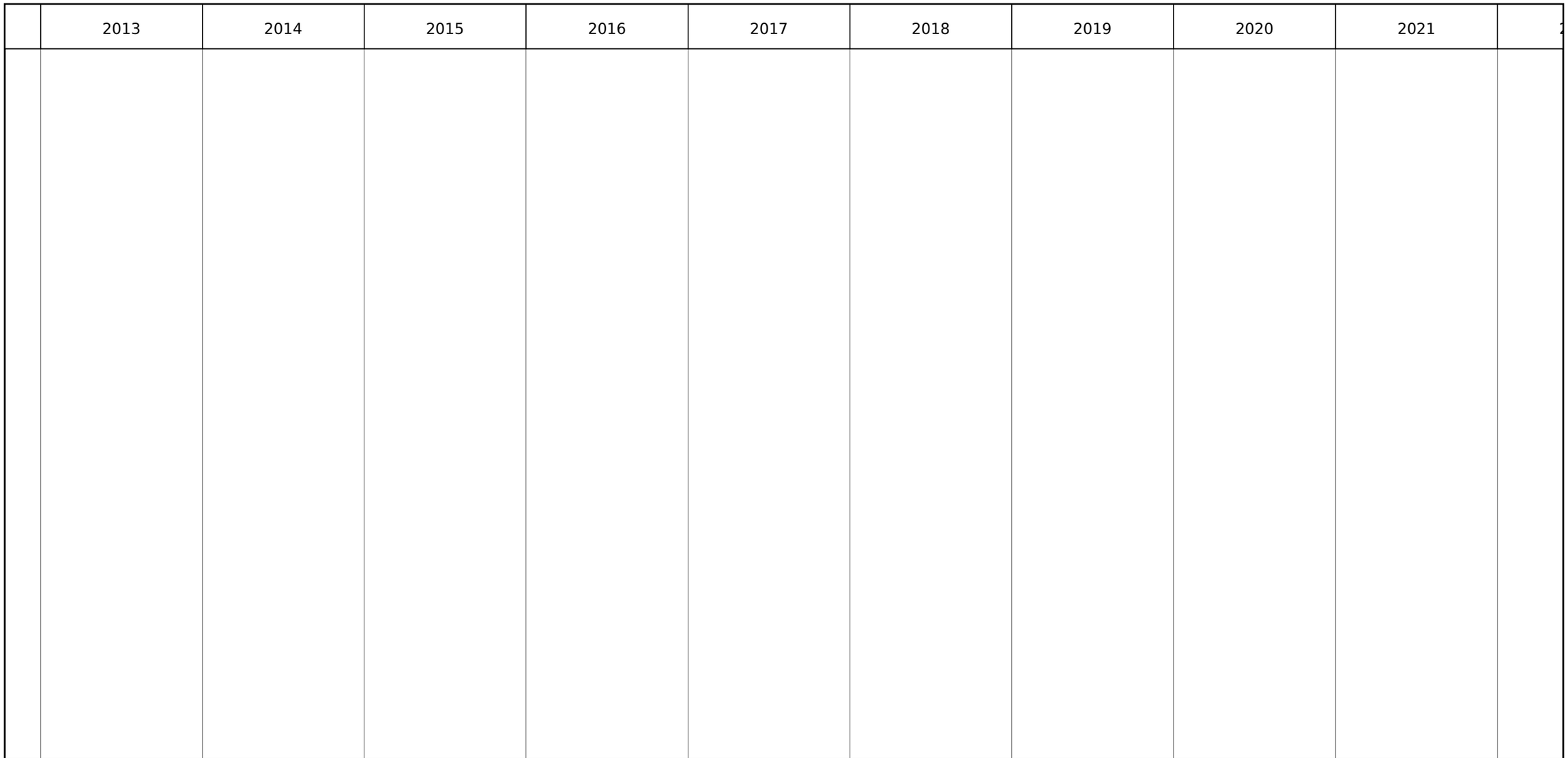


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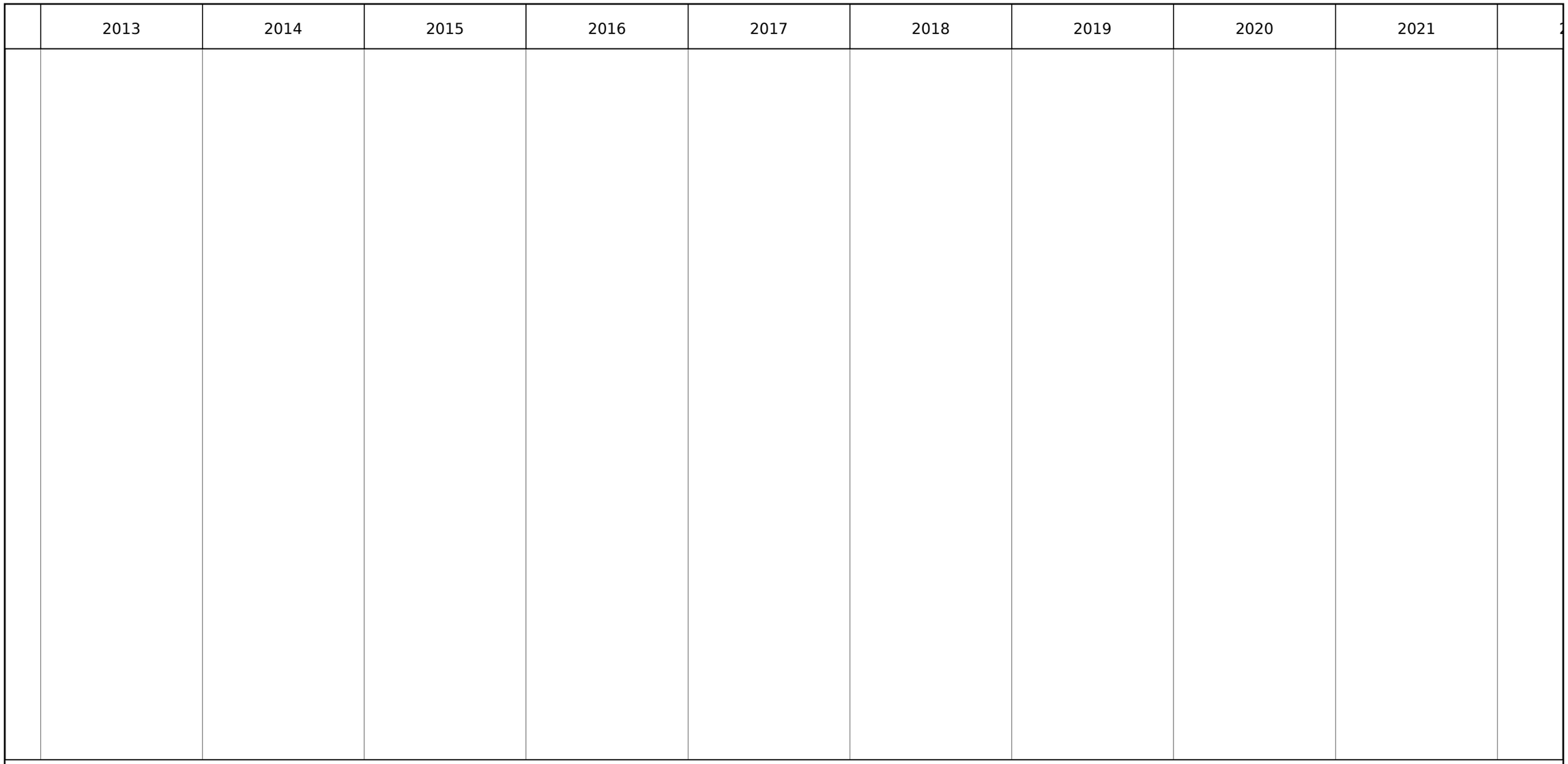


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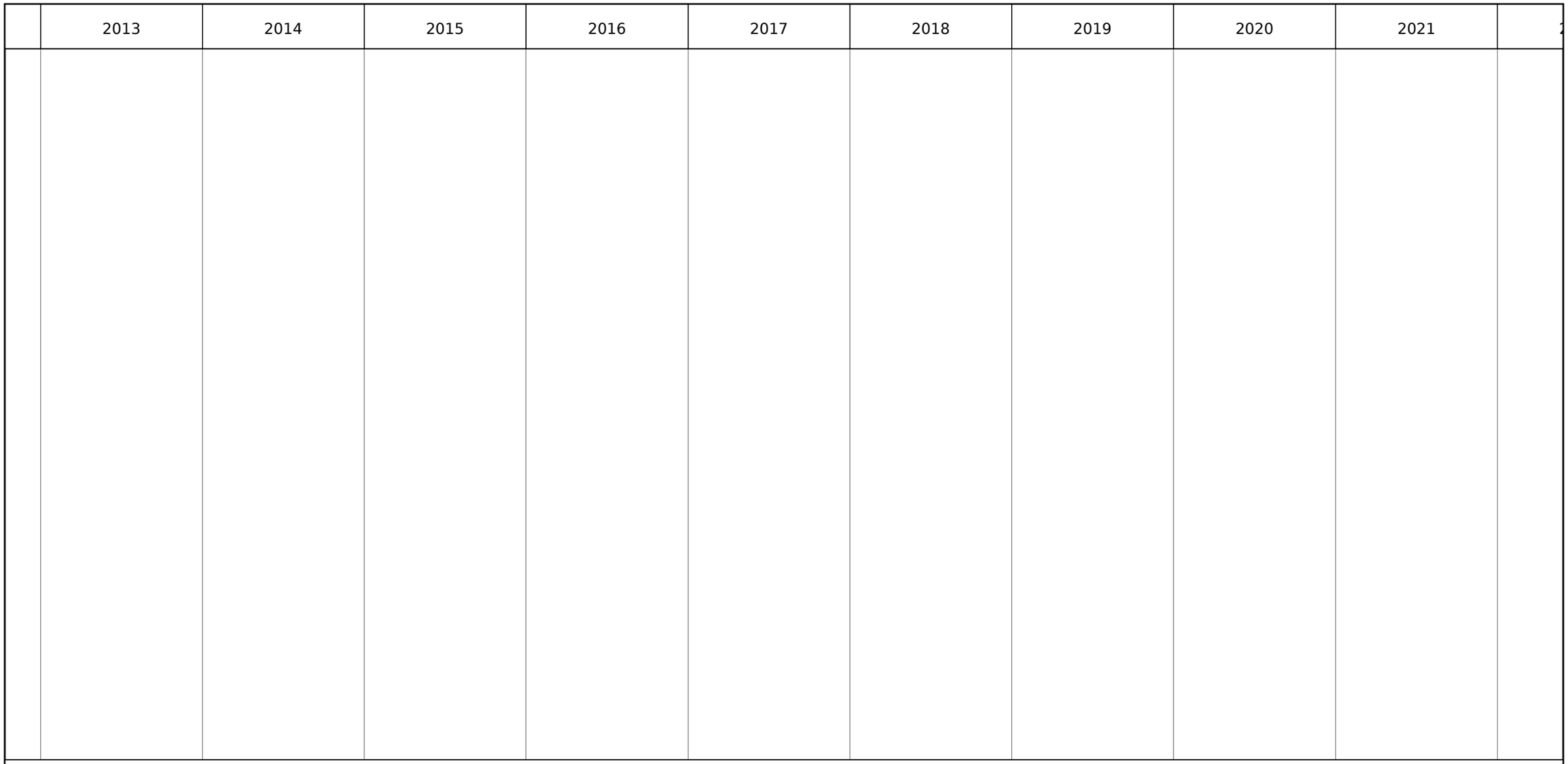


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	2013	2014	2015	2016	2017	2018	2019	2020	2021	

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Compliance Application Notice Prioritization; Criteria, Tool and Proposed Prioritization

Background:
The Compliance Operations department asked each of the Standing Committees to assist in prioritizing a set of 26 requests to develop a compliance application notice (CAN). Ben Li volunteered to work with the Process Subcommittee to develop an objective process for prioritizing CANS that could be used by all of the Standing Committees.

During its January 2012 meeting, the Process Subcommittee developed a draft process for prioritizing CANs and presented this to the Standards Committee for review. The process includes a draft set of criteria with weights that, when applied, develop a "score" for each proposed CAN. The following motion was approved during the January 2012 SC meeting:

> *Volunteers from the SC PS will field test, refine, and then provide for the criteria and associated spreadsheet for review and endorsement during the SC's February SC meeting. Following that meeting, the SC will share the criteria with the other standing committees. On an interim basis, Ben Li will notify Val Agnew & Mike Moon and the chairs of the standing committees to provide them a status report and let them know that the SC will share the proposed criteria and associated spreadsheet by the end of the second week of February.*

Ben Li sent Val Agnew, Mike Moon and the members of the Standing Committees Coordination Group (includes the leadership of NERC's Standing Committees) a letter to advise them of the status of the effort to develop a tool for prioritizing CANs that could be used by all of the Standing Committees.

Volunteers from the SCPS did field test the draft criteria and will present the criteria and associated spreadsheet for endorsement of the full Standards Committee as well as a proposed prioritization of the 26 CANs submitted to the Standards Committee for prioritization.

Request:
Endorse use of the CAN Prioritization criteria, tool, reference document, and resultant proposed prioritization of the 26 CANs presented to the Standards Committee for prioritization.

Ben Li
Vice Chair, Standards Committee

January 30, 2012

NERC Standing Committees Coordination Group
Valerie Agnew, NERC Compliance Operations

Dear Colleagues,

At our last SCCG meeting, I committed that the Standards Committee, through its Process Subcommittee, would work to develop an objective approach for prioritizing CANs, similar to the approach that the Standards Committee has adopted for prioritizing standards development projects. Through this letter, I am providing you a status report on that effort.

The Standards Committee has developed a draft set of criteria for use in prioritizing CANs, along with a draft Excel spreadsheet for assigning a weighted score to each CAN based on these criteria. We are in the process of developing documentation to support the proposed approach to prioritization and conducting a field testing with the draft criteria and weightings. I anticipate that we will be in a position to circulate these work products to you for consideration following the Standards Committee meeting on February 16, 2012.

Please feel free to contact me if you have any questions.

Sincerely,

Ben Li
Vice-chair, Standards Committee

cc: Standards Committee
Standards Committee Process Subcommittee

Project 2008-06 – Cyber Security Order 706 Request for Extended Comment Period

Background:
The Cyber Security Order 706 Standard Drafting Team (CSO 706 SDT) has been working to address the comments submitted by stakeholders during the comment and ballot period for Version 5 CIP standards that ended January 6, 2012. Stakeholders provided very useful guidance in their comments, and the team is still considering those comments and making conforming changes to the standards, definitions, and implementation plan. The team plans to submit its work for a quality review on February 29, 2012.

Request:
In recognition of the resources required in reviewing the Version 5 CIP Cyber Security Standards, the CSO706 Standards Drafting Team (Project 2008-06) requests endorsement from the Standards Committee to:

- Extend the next formal comment period from 30 days to 40 days and conduct a successive ballot during the last 10 days of that formal comment period. The Standards Drafting Team expressly requests that an extension be no longer than 40 days, which would put the team's schedule and planned approach to responding to comments in jeopardy.
- Delay a non-binding poll of VRFs and VSLs in the Version 5 CIP Cyber Security Standards until a subsequent posting to encourage a focus on the CIP Version 5 requirements and measures.

Project 2010-INT-03 – Florida Municipal Power Pool Request for Clarity on TOP-002, Requirements R2, R8, R19

Background:
During its January 2012 meeting, the Standards Committee discussed having the Real-time Operations Standard Drafting Team review the Request for Interpretation submitted by Florida Municipal Power Pool (seeking clarity on Requirements R2, R8, and R19) and determine if that request could be addressed as a "rapid revision" to the standard rather than as an interpretation. The initial reaction was that the revisions would be controversial and unlikely to qualify for rapid revision, however the team agreed to review the interpretation request and report back to the Standards Committee.

The Real-time Operations Standard Drafting Team did review the request for interpretation and determined that it could address the issues raised by FMPP through a set of revisions to the standard and has developed a SAR and a set of proposed revisions in support of that SAR.

Request:

- Authorize posting the SAR and associated revisions to TOP-002-2a – Normal Operations Planning for a 45-day formal comment period with the formation of a ballot pool during the first 30 days and an initial ballot during the last 10 days of that 45-day comment period.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	TOP-002-3 – Normal Operations Planning		
Date Submitted:	February 3, 2012		
SAR Requester Information			
Name:	James Case, Chair of Project 2007-03 Real-time Operations		
Organization:	Entergy		
Telephone:	(601) 985-2345	E-mail:	jcase@entergy.com
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
X Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
There is a need for additional clarity surrounding Requirements R2, R8, and R19 in TOP-002-2a as pointed out in an interpretation request from the Florida Municipal Power Pool.
Purpose or Goal (How does this request propose to address the problem described above?):
This SAR proposes to delete TOP-002-2a, Requirements R2, R8, and R19 to provide the needed clarity.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Address the need for additional clarity in the subject requirements as per the interpretation request.

SAR Information
Brief Description (Provide a paragraph that describes the scope of this standard action.)
Requirements R2, R8, and R19 will be deleted to bring needed clarity to the standard.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Requirement R2 will be deleted. The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and Functional Model v5, operations planning is part of what the Transmission Operator is required to do and as such this requirement is no longer needed and can be deleted. Requirement R8 will be deleted. The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive limits and, thus, this requirement can be deleted as all elements of the requirement are now covered in other standards. Voltage and reactive power balance are the responsibility of the Transmission Operator and are replaced by approved VAR-001-1, Requirement R1. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator's responsibility to manage the transmission system reliability. Requirement R19 will be deleted. This is part of an entity's certification and is no longer required in standards.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

Reliability Functions		
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
X	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
X	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
X	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
X	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
X	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
X	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
X	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Y
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Y
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Y
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Y

Related Standards	
Standard No.	Explanation
	N/A

Related Standards	

Related SARs	
SAR ID	Explanation
	N/A

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	

Regional Variances	
WECC	

Item 6ai

Standards Committee Report to BOT

Action
None

Background
This report highlights some of the key activities of the Standards Committee (SC) in support of ERO Enterprise goals. The SC meets monthly and its meetings minutes are posted at http://www.nerc.com/filez/scmin.html.

Major Accomplishments for 2011:
The three standards projects that were completed in 2011 expected to have the greatest impact on bulk power system reliability are:

- **Definition of Bulk Electric System**
- **TPL-001-2 – Transmission System Planning Performance Requirements**
- **CIP-002-4 – Cyber Security — Critical Cyber Asset Identification**

Major Tasks for 2012:
- **Revisions to Standards Process**
  The SC will identify changes to the standard development process that would result in developing a standard in a shorter period of time without adversely impacting either the technical quality of the standards or jeopardizing ANSI's accreditation of the NERC standards development process.
- **Aggressively pursue high priority standards associated with topics most critical to bulk power system reliability:**
  - Protection systems (PRC-001, PRC-005, PRC-019, PRC-024)
  - Real-time system operator communications (COM-002, COM-003)
  - Cyber-security (CIP-002 through CIP-011)
  - Frequency response (BAL-003)
- **Continue refinement of the Definition of BES through Phase 2 as a High Priority project**

Standards Committee Strategic Plan's Linkages to NERC Strategic Plan to Improve Reliability
- ***Initiatives Linked to the ERO Goal 1: The ERO will have clear, results-based reliability standards that provide for an adequate level of bulk power system reliability.***
  - Conduct a root cause analysis to identify why standard development doesn't move more rapidly; use results to revise the standard development process for improved efficiency
  - Improve application, monitoring, and communication of the results based standards process
  - Pursue modifications to the standard elements and template including possible removal of compliance elements and closer alignment between measures and reliability standard audit worksheets

- Complete proposals for revising the criteria for setting violation risk factors and violation severity levels
- Collect audit observations as input to standards development

- ***Initiatives Linked to ERO Goal 2: Bulk power system owners, operators, and users will demonstrate sustained cultures of learning and reliability excellence, built upon underlying foundations of compliance and effective risk management and mitigation.***
  - Continue to pursue methods of assessing the cost effectiveness of proposed reliability standards; pursue as a tool in support of risk management and risk mitigation.
  - Support development of an ERO enterprise-wide process for responding to/taking proactive action for protection of the bulk power system from high impact low frequency events and other emerging issues

- ***Initiatives Linked to ERO Goal 3: The ERO will develop and maintain effective reliability performance measures and will continue to develop high quality reliability assessments based on long range and seasonal forecasts, as well as emerging issues.***
  - Integrate the results of the ALRTF into standards development

- ***Initiatives Linked to ERO Goal 4: Bulk power system owners, operators, and users will effectively manage risks from cyber and physical attacks and other high-impact, low-frequency events.***
  - Complete CIP Version 5 standards

- ***Initiatives Linked to ERO Goal 7: The ERO will maintain an exceptional reputation as the trusted leader of the reliability community and instill a high degree of confidence in the reliability of the bulk power system.***
  - Support development of an ERO enterprise-wide process for responding to emerging issues, which may include development of new or revised reliability standards
  - Continue to provide guidance on effective participation in the standard development process
  - When initiating a new standard project, identify whether the intent is to "raise the bar" or improve "clarity" of existing requirements
  - Develop a "maturity model" for standards where successive versions of standards are more performance-based and less prescriptive
  - Improve transparency to stakeholders of FERC staff guidance provided to drafting teams

If members of the BOT have questions or need additional information, they may contact Herb Schrayshuen at herb.schrayshuen@nerc.net or Allen Mosher at amosher@publicpower.org.

Item 6aii

Report from SC for BOT SOTC

Since the last Board of Trustees meeting, the Standards Committee (SC) has met by conference call on November 10 and December 7 and is scheduled to meet in person on January 11-12, 2012. SC meeting agendas and minutes are posted at: http://www.nerc.com/filez/scmin.html

This report outlines major ongoing activities and policy issues under consideration by the SC and its subcommittees that may be of interest to the Standards Oversight and Technology Committee.

Key Issues Discussed During Joint meeting with CCC on December 7, 2011:

The Standards Committee had a joint meeting with the Compliance and Certification Committee on December 7, 2011 and identified the following opportunities for future joint activities:

- Involve drafting teams in the development of reliability standard audit worksheets (RSAWs) with a possibility of eventually eliminating measures from standards
- Commitment to provide the compliance program with support in prioritizing its list of Compliance Application Notices proposed for future development
- Continued support of the proposal to replace violation risk factors with an objective scoring system and with the proposal to replace violation severity levels (VSLs) with a set of pro forma VSLs

During the January 11-12, meeting, the Standards Committee will make forward movement on the following:

- **Revisions to Standard Development Process**
  The SC is reviewing the standard development process and identifying ways of shortening the process without losing ANSI accreditation. Potential ideas already identified by staff for SC discussion include:
  - Use technical subject matter experts to serve as panelists to provide technical input on a standard, but have a team of interviewers (legal, technical writer, compliance) capture that information and develop a draft standard. The technical experts then review the standard to determine if it is technically accurate; each requirement achieves its reliability objective; the collection of requirements meets the standard's purpose.
  - Use stakeholder groups to provide preliminary informal feedback on a standard before it is publicly posted – so that the standard is 90% correct before its first public comment period.
  - Establish a one-year schedule for projects; 5 months to develop the initial draft and collect informal feedback to bring the standard to the 90% acceptance level; 7 months to conduct required balloting and formal consensus building.

- Replace the Registered Ballot Body (now over 1000 members) with “delegates” that represent industry segments. Use delegates for collection and organization of comments and balloting. Stakeholders would continue to have the right to submit individual comments during public postings.

- **Triage Process for Determining How to Respond to Lessons Learned/Emerging Issues**

  The SC is drafting a process for reviewing information from analyses of events and emerging issues and determining what the ERO enterprise (including the SC and leaders of other committees and stakeholder groups) should do with that information to minimize risk to reliability. In some instances, the information gleaned from an event may lead to an alert, in other instances the response to an emerging issue may result in the development of a standard, guideline, training program, reference document or another product.

- **Rapid Revision Process**

  The SC field tested a rapid revision process that provides a revision to a standard as an alternative response to a request for an interpretation of an approved standard. The initial field test resulted in a permanent revision to the standard approved by its ballot pool in less than 90 calendar days from initial posting through completion of the recirculation ballot. The lessons learned from the field test will be used to document the process for future use.

S - Vacancy Report

Attachment 8a

Project	Vacancy Description
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 (TDU) with xperience in analyzing or modeling frequency response.

Standards Committee 2012 Roster

Chair **2012-2013**	Allen Mosher Senior Director of Policy Analysis and Reliability	American Public Power Association 1875 Connecticut Avenue NW Twelfth Floor Washington, D.C. 20009-5715	(202) 467-2944 amosher@publicpower.org
Vice Chair **2012-2013**	P.S. (Ben) Li President	Ben Li Associates, Inc. 37 Goldring Crescent Markham, Ontario L6C 1Y6	(647) 388-1498 ben@benli.ca
Segment 1-2011-12	Jason Shaver Manager – CIP Program Office	American Transmission Company, LLC W234 N2000 Ridgeview Pkwy. Ct. Waukesha, WI 53188-1022	(262) 506-6885 jshaver@atcllc.com
Segment 1-2012-13	Carol A. Sedewitz Director, Transmission Planning	National Grid 40 Sylvan Road Waltham, MA 02451	(781) 907-2500 carol.sedewitz@us.ngrid.com
Segment 2-2011-12	*Vacant*		
Segment 2-2012-13	H. Steven Myers Principal, Operating & Planning Standards	ERCOT 2705 West Lake Drive Taylor, TX 76574	(512) 248-3077 smyers@ercot.com
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Segment 3-2012-13	John Bussman Manager Reliability Compliance	Associated Electric Cooperative Inc PO Box 754 Springfield, MO 65802	(417) 885-9216 jbussman@aeci.org
Segment 4-2011-12	Joseph Tarantino Regulatory Compliance Coordinator	Sacramento Municipal Utility District 6002 S Street b303 Sacramento, California 95852	(916) 732-5812 JTarant@smud.org

Segment 4-2012-13	Frank Gaffney Regulatory Compliance Officer	Florida Municipal Power Authority 8553 Commodity Circle Orlando, FL 32819-9002	(321) 239-1026 Frank.gaffney@fmpa.com
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Segment 5-2012-13	Scott Miller Manager, Corporate Affairs	MEAG Power 1470 Riveredge Parkway NW Atlanta, GA 30328	(678) 644-3524 smiller@meagpower.org
Segment 6-2011-12	Silvia Parada Mitchell Director, NERC Reliability Standards & Compliance	NextEra Energy, Inc. 700 Universe Blvd. Juno Beach, FL 33408	(561) 694-4414 Silvia.Parada.Mitchell@fpl.com
Segment 6-2012-13	Alice Murdock Ireland Reliability Standard Analyst	Xcel Energy, Inc. 1800 Larimer St., Suite 1400 Denver, CO 80202	(303) 571-7868 alice.murdock@xcelenergy.com
Segment 7-2011-12	John A. Anderson President & CEO	Electricity Consumers Resource Council 1333 H Street, N.W. 8th Floor, West Tower Washington, D.C. 20005	(202) 682-1390 janderson@elcon.org
Segment 7-2012-13	Frank McElvain Senior Consulting Manager	Siemens Energy, Inc. Siemens Power Technologies International 1350 Shorebird Way Mountain View, CA 94043-1338	(650) 694.5096 frank.mcelvain@siemens.com
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Segment 8-2012-13	Frederick Plett Utility Analyst	Massachusetts Attorney General One Ashburton Place, 18th Fl. Boston, MA 02108	(617) 963-2183 Frederick.plett@state.us.ma
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Segment 9-2012-13	Klaus Lambeck Chief Facilities, Siting and Environmental Analysis	Public Utilities Commission of Ohio/the Ohio Power Siting Board 180 E. Broad Street Columbus, OH 43215-3793	(614) 644 82 44 Klaus.Lambeck@puc.state.oh.us
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Segment 10-2012-13	Linda Campbell Vice President and Executive Director, Standards and Compliance	Florida Reliability Coordinating Council 1408 N. Westshore Blvd. Suite 1002 Tampa, Florida 33607-4512	(813) 207-7961 lcampbell@frcc.com
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Parliamentary Procedures

Based on Robert's Rules of Order, Newly Revised, 10th Edition, plus "Organization and Procedures Manual for the NERC Standing Committees"

Motions

Unless noted otherwise, all procedures require a "second" to enable discussion.

When you want to…	Procedure	Debatable	Comments
Raise an issue for discussion	Move	Yes	The main action that begins a debate.
Revise a Motion currently under discussion	Amend	Yes	Takes precedence over discussion of main motion. Motions to amend an amendment are allowed, but not any further. The amendment must be germane to the main motion, and can not reverse the intent of the main motion.
Reconsider a Motion already approved	Reconsider	Yes	Allowed only by member who voted on the prevailing side of the original motion.
End debate	Call for the Question *or* End Debate	Yes	If the Chair senses that the committee is ready to vote, he may say "if there are no objections, we will now vote on the Motion." Otherwise, this motion is debatable and subject to 2/3 majority approval.
Record each member's vote on a Motion	Request a Roll Call Vote	No	Takes precedence over main motion. No debate allowed, but the members must approve by 2/3 majority.
Postpone discussion until later in the meeting	Lay on the Table	Yes	Takes precedence over main motion. Used only to postpone discussion until later in the meeting.
Postpone discussion until a future date	Postpone until	Yes	Takes precedence over main motion. Debatable only regarding the date (and time) at which to bring the Motion back for further discussion.
Remove the motion for any further consideration	Postpone indefinitely	Yes	Takes precedence over main motion. Debate can extend to the discussion of the main motion. If approved, it effectively "kills" the motion. Useful for disposing of a badly chosen motion that can not be adopted or rejected without undesirable consequences.
Request a review of procedure	Point of order	No	Second not required. The Chair or secretary shall review the parliamentary procedure used during the discussion of the Motion.

Notes on Motions

Seconds. A Motion must have a second to ensure that at least two members wish to discuss the issue. The "seconder" is not recorded in the minutes. Neither are motions that do not receive a second.

Announcement by the Chair. The Chair should announce the Motion before debate begins. This ensures that the wording is understood by the membership. Once the Motion is announced and seconded, the Committee "owns" the motion, and must deal with it according to parliamentary procedure.

Voting

Voting Method	When Used	How Recorded in Minutes
Unanimous Consent	When the Chair senses that the Committee is substantially in agreement, and the Motion needed little or no debate. No actual vote is taken.	The minutes show "by unanimous consent."
Vote by Voice	The standard practice.	The minutes show Approved or Not Approved (or Failed).
Vote by Show of Hands (tally)	To record the number of votes on each side when an issue has engendered substantial debate or appears to be divisive. Also used when a Voice Vote is inconclusive. (The Chair should ask for a Vote by Show of Hands when requested by a member).	The minutes show both vote totals, and then Approved or Not Approved (or Failed).
Vote by Roll Call	To record each member's vote. Each member is called upon by the Secretary,, and the member indicates either "Yes," "No," or "Present" if abstaining.	The minutes will include the list of members, how each voted or abstained, and the vote totals. Those members for which a "Yes," "No," or "Present" is not shown are considered absent for the vote.

Notes on Voting

(Recommendations from DMB, not necessarily Mr. Robert)

Abstentions. When a member abstains, he is not voting on the Motion, and his abstention is not counted in determining the results of the vote. The Chair should not ask for a tally of those who abstained.

Determining the results. The results of the vote (other than Unanimous Consent) are determined by dividing the votes in favor by the total votes cast. Abstentions are not counted in the vote and shall not be assumed to be on either side.

"Unanimous Approval." Can only be determined by a Roll Call vote because the other methods do not determine whether every member attending the meeting was actually present when the vote was taken, or whether there were abstentions.

Majorities. Robert's Rules use a simple majority (one more than half) as the default for most motions. NERC uses 2/3 majority for all motions.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Committee Expectations

Approved by Standards Committee January 12, 2012

Background

Standards Committee (SC) members are elected by members of their segment of the Registered Ballot Body, to help the SC fulfill its purpose. According to the Standards Committee Charter, the SC's purpose is:

> *In compliance with the NERC Reliability Standards Development Procedure, the Standards Committee manages the NERC standards development process for the North American-wide reliability standards with the support of the NERC staff to achieve broad bulk power system reliability goals for the industry. The Standards Committee protects the integrity and credibility of the standards development process.*

The purpose of this document is to outline the key considerations that each member of the SC must make in fulfilling his or her duties. Each member is accountable to the members of the Segment that elected them, other members of the SC, and the NERC Board of Trustees for carrying out their responsibilities in accordance with this document.

Expectations of Standards Committee Members

1. SC Members represent their segment, not their organization or personal views. Each member is expected to identify and use mechanisms for being in contact with members of the segment in order to maintain a current perspective of the views, concerns, and input from that segment. NERC can provide mechanisms to support communications if an SC member requests such assistance.

2. SC Members base their decisions on what is best for reliability and must consider not only what is best for their segment, but also what is in the best interest of the broader industry and reliability.

3. SC Members should make every effort to attend scheduled meetings, and when not available are required to identify and brief a proxy from the same segment. Standards Committee business cannot be conducted in the absence of a quorum, and it is essential that each Standards Committee make a commitment to being present.

4. SC Members should not leverage or attempt to leverage their position on the SC to influence the outcome of standards projects.

5. The role of the Standards Committee is to manage the standards process and the quality of the output, not the technical content of standards.

From:	Jones, Donald
To:	rsg
Cc:	"rsg (rsg@listserv.nerc.com)"
Subject:	Standards Committee - TOP-002 Rapid Revision Proposal
Date:	Monday, February 13, 2012 11:10:21 AM

Steve & Linda:

I am writing to you in your capacity as Segment 10 Representatives on the Standards Committee. We are concerned about the proposed Rapid Revision to TOP-002, which is on the SC agenda this week (5d). The proposal appears to be to delete three requirements from the standard, in order to address issues raised in an interpretation request.

Without getting into the substance of the proposed changes, we do not believe that these are simple, non-controversial changes that qualify for Rapid Revision treatment. While we agree that some revisions to this standard may be in order, and that there might be a non-controversial approach to revise the standard (such as modifying the entities required to comply with certain requirements), simply deleting entire requirements is not it. (Our brief review of this matter indicates that the deleted requirements are NOT all covered by other standards.)

As a CEA and member of the ERO, we are concerned that the proposed deletions go too far, and that the industry may vote adopt this proposal to eliminate requirements even though it reduces the level of reliability of the BES. We urge you to consider opposing the application of the Rapid Revision process to this SAR at the SC meeting this week.

Regards,

Don Jones
Reliability Standards Manager
Texas Reliability Entity, Inc.
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don.jones@texasre.org

Y

From:	Gerard J. Dunbar
To:	Guy V. Zito
Cc:	Lee R. Pedowicz
Subject:	Meeting Notes.....SCPS.....SC.....RSG.....January 10, January 11, January 12
Date:	Thursday, January 12, 2012 8:44:44 PM

Tuesday January 10, 2012 ……Standards Committee Process Subcommittee (SCPS):

Administrative:

- Jason Shaver and Pat Brown leaving SCPS.

Agenda Item 1a:

- Process for use of Drafting Teams to assist in developing RSAWs (Audit Worksheets):

  A small group will be formed comprised of Standards Staff and Compliance Staff to develop an approach that would ultimately be presented to the SC.

  The SCPS discussed this item in the context of the possibility of eventually eliminating Measures from the Standards…..the idea being that if the RSAW is precisely written a Measure will not be required.

Agenda Item 1b:

- Process for replacing an appointed drafting team member:

  David Kiguel led the discussion.

  The SCPS made some changes to the draft document…….significantly they removed the questionnaire and revised language in the guidelines……they agreed to leave the obstruction issue but moved it.

Agenda Item 1c:

- Rapid Revision process…….the SCPS discussed proposing a **single portal concept**…….where NERC will triage a request and decide whether a request is resolved as either a CAN, an Interpretation, Rapid Revision, or Standard Development.

Agenda Item 2a:

- Prioritizing CAN's:

  SCPS reviewed a tool developed by Linn Oelker for prioritizing CAN's ……very similar to tool developed to prioritize standard development…….only the criteria has been

changed……..will be introduced to the SC.

Agenda Item 2a:

- Proposal to eliminate the Quality Review Advisory Working Group (QRAWG)…..SCPS does not support eliminating……NERC staff will present the proposal to the SC….

  Next meeting ……Tampa April 10th……..Ben recommending a full day meeting since he was not able to get to all agenda items.

Wednesday January 11, 2012…..Standards Committee Day 1:

Note: See separate notes on Alternative Standard Development Procedure

Summary of high priority projects.

- BES on track to go the NERC BOT on 1/18…..and on schedule to be presented to FERC.

- 6 Projects on schedule.
  7 Projects behind schedule.

- Herb commented that NERC will occasionally hold back posting a standard if too many standards are posted at one time…..that can lead to a project falling behind…..Herb keeps Allan Mosier informed of these circumstances……NERC refers to these situations as 'posting constraints'.

- SC had a long discussion on PRC -005……..the importance of the standard and the number of violations (high)….Charles Rogers SDT chair called in……PRC -005 narrowly failed the recirc. ballot last summer and a new ballot pool was formed according to procedure…..significant drop in approval on initial ballot of new ballot pool seems to be related to the new ballot pool members…..Charles Rogers optimistic and expects a successful ballot….Allen Mosier recommending a Technical Conference …..Carol Sedewitz, suggested a regional Technical Conference…..

- Project 2007-12 Frequency response……SC endorsed revised schedule… ongoing concern over the BA being held responsible for frequency response if they don't own the asset…..

Update on outstanding Interpretations…….

- Interpretation on the definition of a 'single point of failure'……. submitted in Dec . 2011 for TPL 003 and TPL 004…Carol Sedewitz concern…….there is an existing NERC data request that is looking for information on the same issue……..concern over available resources to answer data request and develop the Request for Interpretation on this same issue…..also there is the potential for the issue to become tangled in the TPL standard which is

currently before FERC…..

Candidates for Rapid Revision…..

- SC had a lengthy discussion on two FMPP interpretatations of existing TOP standards …… existing body of TOP standards are currently being balloted…..FMPP concern is addressed in the current balloted standards…..concern though is that successive ballots and recirc. Ballot and NERC and FERC approvals and implementation plan could take a very long time….intent with the rapid revision is to make focused changes on the existing body of standards…interpretation of TOP002 is more involved and would not be a good candidate for a rapid revision……SC approved a motion for a rapid revision of TOP-006…

  Also another interpretation request for a VAR standard…….no team in place…but SC approved motion to move the VAR standard to a Rapid Revision process.

Mike Gildea asked for a discussion on the status of Results Based Standards…..

- Mike is concerned that it seems to no longer be a priority with NERC……Herb and Andy Rodriguez countered that despite the fact that no one is talking about them results based standards has been internalized at NERC and is still very much how they approach standard development…..FAC 003 Veg. Man. currently before FERC and the first NERC BOT approved results based standard will be the acid test since NERC will receive FERC comments on results based…..Herb agreed to post on the NERC website a list of those standards that are being developed as results based….

Jim Castle presented on behalf of the NAESB Business Practices Sub Committee

- Jim requested NERC to elevate the priority of Interchange Standard Development in order to support conforming changes in the NAESB business practice efforts……intra BA transactions need to be tagged… limited modifications for IRO-006-East -1…..

  NAESB can move ahead with the business practice…….Operating Reliability Subcommittee (ORS) needs to identify any reliability gaps…….no SC action at this time…

Ben Li reviewed the CAN priority tool…….(see SCPS notes on the CAN priority tool above.)

- SC approves this approach and will send to other standing committees (CCC)for their action.

SC heard NERC staff proposal to eliminate the Quality Review Advisory Working Group (QRAWG) …..

- QRAWG provides administrative oversight on behalf of the SC……NERC would like the SC Exec Comm. will now provide this oversight… extended discussion among the SC……many felt that the QRAWG provides value….

SC approved motion to eliminate QRAWG but assign staff to bring significant issues to the SC Exec Comm.

Thursday January 12, 2012…..Standards Committee Day 2:

- Carol Sedewitz, Frank McElvain and Steve Rueckert appointed to the SC nominating committee for the SC Executive Board.
  Above nominating committee presented the following slate to serve as at large members on the SC Exec Comm.: David Kiguel, Jason Shaver, and John Bussman.

- Top priority Standards for 2012 : CIP, BES Phase 2, 3 Part Communication, PRC and Frequency Response

- Proposed SC initiatives to align with 7 broad ERO goals: Maureen Long to distribute

- Linda Campbell on behalf of the SCPS……..development of a plan to allow RSAWs to be developed by the SDT……a Working Group, comprised of Compliance, Standards and NERC lawyers will develop the plan……when developed the plan will be submitted to the NERC BOT…..other questions to be answered …..do we eliminate Measures?…..do the RSAW's go to FERC when the standard is approved?....SC approved motion for WG to develop plan and present the plan to the SC.

- Maureen Long on behalf of the SCPS reviewed a plan to develop a Rapid Revision Process…….via a single portal process NERC would triage the request to determine if a question on some aspect of a standards requirements should be resolved either by Rapid Revision, CAN, Interpretation or Standard Development Process….. MOD 28 was handled in this manner and resolved via a Rapid Revision…

  Two motions approved by the SC……develop a formal Rapid Revision Procedure…..and develop a formal Triage Process.

- Ben Li on behalf of the Standards Committee Process Subcommittee……

  Presented red lined document on the Standard Drafting Team Scope…
  SC approved motion to accept proposed revisions.

  Two vacancies on the SCPS (Patrick Brown and Jason Shaver leaving)…….SC soliciting replacement candidates for the SCPS……Scott Miller volunteered……..

- Mike Gildea on behalf of the Communication and Planning Subcommittee….

Good feedback on the Weekly Standards Bulletin…considering some enhancements.

Two Standards and Compliance Workshops to be announced for 2012…….one in April and another in the Fall……..in between the two Workshops will be a Standards only 'State of the Standards' Webinar……..Webinar tentatively scheduled for July…..

- Laura Hussey discussion on the RBB……

RBB is cumbersome……NERC looking to verify that the existing RBB is comprised in a manner consistent with the Rules of Procedures. NERC will be looking to verify that affiliates are not represented by the same individual.

NERC also looking to verify existing affiliates.

NERC will be surveying members of the RBB between Feb and July to verify affiliates and representatives in order to verify integrity of voting process.

- Update on Regulatory:

Enforcement dates for Canadian entities will be updated shortly.

Regional UFLS Standards filed for SERC and TRE.

NERC submitted comments on the FERC NOPR for UFLS (continent wide).

David Kiguel commented on the recent Ontario rule that says the standards in Ontario are now effective when they become effective in the United States (FERC approval)…..as opposed to in the past upon NERC BOT approval.

- Update on the RSG (Herb):

MRO not supporting regional standards…..RFC on the fence…..Herb encouraged RFC to develop UFLS.

- I provided the SC with an update on the status of the NPCC Cost Effectiveness Procedure.

Motion for the SCPS to document the pros and cons of using the NPCC Cost Effectiveness Procedure and bring back a recommendation to the SC.

Thursday January 12, 2012…..Regional Standards Group Meeting:

- Review of Action Items:…..

    1. RSG Meeting Dates for 2012 distributed……item closed.
    2. Update Schedule for Protection System Mis-operations…..item closed.

- Update Rapid Development Project….Protection Systems Mis-Operations….45 day formal comment period expected in May…..Observation Report from Will Smith……(nothing to add).

- Agenda Item #8….**Action Item: Business Plan and Budget Common Assumptions 2013…. 8 Questions under Reliability Standards… NERC looking for a consensus responses …..**Howard to distribute Questions to the RSG……**regions will respond by Jan. 23 .**

- Agenda Item #9…Round Table Discussion….Discussion of Eastern Interconnect vs. Regional Standards…Will Smith to lead group reporting to the EMG…..group to explore the possibility of developing an (Eastern) Interconnection wide Standard…..Tuesday Jan. 17th @1pm (2 hrs)……initial conference call to discuss this concept…

- Howard will send out request for schedule updates(Development of Regional Standards).

- Agenda Item #11….discussion surrounding how the regions are posting their Regional Standards…..the NPCC approach…..once NERC BOT approves the standard the NPCC website will jump to the NERC website for current status and mandatory enforcement dates….suggested that all the Regions adopt a consistent approach…NERC website is improving in this regard……Provincial Dates were discussed at the SC and will be updated shortly.

- VRF Definitions and VSL Pro Forma Proposal…….conference call on Monday…….regions can participate.

- Agenda Item#13 Future RSG Dates….2/21 teleconference….3/12 teleconference…..4/13 Tampa.

- RFC has suspended the development of Regional Standards…..the issue is the impact of regional standards on multi regional entities

- FRCC, ERCOT, and SERC waiting for the DME continent wide before developing DME Regional Standard…..NERC and FERC pointed out that continent wide DME is not being actively developed….. FRCC, ERCOT, and SERC relying on regional criteria.

- Regional Standards and Variances…. ….concern about the SC telling a region how to prioritize development of a regional standard….. Howard Gugel whitepaper…….Howard and Don Jones will strip down the document and just answer the question of what is the

difference between a regional standard and a variance… the process language in the original document will be eliminated…..a conference call for the RSG on Feb. 3 will be scheduled to edit Howards and Don's product… once the RSG agrees on an answer to this question…… the RSG will report to the SC…..

Gerry Dunbar
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