UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)** **)**	**Docket No. RR06-1-000**

QUARTERLY REPORT OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION REGARDING ANALYSIS OF RELIABILITY STANDARDS VOTING RESULTS JULY – SEPTEMBER 2009

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I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] submits its third quarter 2009 report on the analysis of voting results for Reliability Standards. This filing is submitted in response to the Federal Energy Regulatory Commission's ("FERC") January 18, 2007 Order[2] that requires NERC to closely monitor and report to FERC the voting results for NERC Reliability Standards each quarter for three years. This third quarter 2009 report covers balloting results during the July 1, 2009 – September 30, 2009 time frame and includes NERC's analysis of the voting results, including trends and patterns of stakeholder approval of NERC Reliability Standards.

II. NOTICES AND COMMUNICATIONS

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

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[1] NERC has been certified by FERC as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006).

[2] *Order on Compliance Filing*, 118 FERC ¶ 61,030 at P 18 (2007).

III. BACKGROUND

NERC develops Reliability Standards in accordance with Section 300 of its Rules of Procedure and the NERC *Reliability Standards Development Procedure*, which is Appendix 3A to the Rules of Procedure.[3] In order for an entity or individual to vote on a proposed Reliability Standard or interpretation ("standard action"), the individual or entity must join the registered ballot body, which includes all entities or individuals that qualify for one of ten stakeholder segments and have registered with NERC as potential voting participants. Each member of the registered ballot body is eligible to participate in the voting process and ballot pool for each standard action. The ten stakeholder segments are:

- Transmission Owners
- Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs")
- Load-Serving Entities ("LSEs")
- Transmission Dependent Utilities ("TDUs")
- Electric Generators
- Electricity Brokers, Aggregators, and Marketers
- Large Electricity End Users
- Small Electricity Users
- Federal, State, and Provincial Regulatory or other Government Entities
- Regional Reliability Organizations and Regional Entities

Each standard action has its own ballot pool, populated by interested members of the registered ballot body. The individuals who join a ballot pool respond to a pre-ballot e-mail announcement associated with each Reliability Standard ballot action. The ballot pool votes to approve or reject each standard action. Specifically, the ballot pool votes determine: first, the

[3] Version 6.1 of the *Reliability Standards Development Procedure*, effective June 7, 2007, is the latest Commission-approved version.

need for and technical merits of a proposed standard action; and second, that appropriate consideration of views and objections received during the development process was undertaken.

The *Reliability Standards Development Procedure* process includes three types of ballots: an initial ballot, a recirculation ballot and a re-ballot. If an initial ballot achieves a quorum, but includes at least one negative ballot submitted with comments on the proposed standard action, then a recirculation ballot must be conducted. If an initial ballot does not achieve a quorum, then a re-ballot is conducted using the same ballot pool, but with an extended ballot window.

Approval of a standard action requires both:

- A quorum, which is established by at least 75% of the members of the ballot pool for the standard action submitting a response with an affirmative vote, a negative vote, or an abstention; and
- A two-thirds majority of the weighted segment votes cast must be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

The following process is used to determine if there are sufficient affirmative votes:

- The number of affirmative votes cast in each segment is divided by the sum of affirmative and negative votes cast in the segment to determine the fractional affirmative vote for each segment. Abstentions and non-responses are not counted for the purposes of determining the fractional affirmative vote for a segment.
- If there are less than ten entities that vote in a segment, the vote weight of that segment is proportionally reduced. Each voter within that segment voting affirmative or negative receives a weight of 10% of the segment vote. For segments with ten or more voters, the regular voting procedures are followed.
- The sum of the fractional affirmative votes from all segments divided by the number of segments voting[4] is used to determine if a two-thirds majority affirmative vote has been achieved. (A segment is considered as "voting" if any member of the segment in the ballot pool casts either an affirmative or a negative vote.)
- A standard is approved if the sum of fractional affirmative votes from all segments divided by the number of voting segments is greater than two-thirds.

[4] When less than ten entities vote in a segment, the total weight for that segment is determined as one tenth per entity voting.

IV. SUMMARY OF BALLOTS DISCUSSED IN THIS REPORT

NERC conducted 37 ballots from July 1, 2009 – September 30, 2009, each undertaken using the NERC *Reliability Standards Development Procedure*. These 37 ballots can be grouped into 17 distinct groups of ballot events as follows:

- Violation Severity Levels ("VSLs") for Critical Infrastructure Protection ("CIP") Standards CIP-002-1 through CIP-009-1 – One (1) Recirculation Ballot
- Interpretation of MOD-001-1, Requirements R2 and R8 and MOD-029-1, Requirements R5 and R6 for the New York Independent System Operator – One (1) Recirculation Ballot
- NUC-001-2 — Nuclear Plant Interface Coordination – One (1) Recirculation Ballot
- Interpretation of PRC-005-1, Requirement R1 for the Compliance Monitoring Processes Working Group – One (1) Recirculation Ballot
- Interpretation of TPL-002-0, Requirement R1.3.10 for PacifiCorp – One (1) Recirculation Ballot
- Reliability Standards Development Procedure - Version 7 – One (1) Initial Ballot, One (1) Re-ballot, and One (1) Recirculation Ballot
- VSLs for all Groups of Standards – Nine (9) Initial Ballots and Nine (9) Recirculation Ballots
- Interpretation of PRC-004-1, Requirements R1 and R3 and PRC-005-1, Requirements R1 and R2 for Y-W Electric and Tri-State – One (1) Initial Ballot
- Interpretation of CIP-001-1 Requirement R2, for Covanta Energy – One (1) Initial Ballot
- Implementation Plan for CIP-002-1 through CIP-009-1 for Nuclear Power Plants (Order 706-B) – One (1) Initial Ballot and One (1) Recirculation Ballot
- Interpretation of EOP-002-2 for Brookfield Power, Requirements R6.3 and R7.1 – One (1) Recirculation Ballot
- Interpretation of CIP-005-1, Section 4.2.2 and Requirement R1.3 for PacifiCorp – One (1) Initial Ballot
- Interpretation of CIP-006-1, Requirement R1.1 for PacifiCorp – One (1) Initial Ballot
- BAL-006-2 and INT-003-3 (Removal of Three Midwest ISO Waivers) – One (1) Initial Ballot
- Interpretation of CIP-007-1, Requirement R2 for the Western Electricity Coordinating Council – One (1) Initial Ballot

- Violation Severity Levels (“VSLs”) for CIP Standards CIP-002-2 through CIP-009-2 and Violation Risk Factors (“VRFs”) for CIP-003-2 and CIP-006-2 – One (1) Initial Ballot
- EOP-008-1 — Loss of Control Center Functionality – One (1) Initial Ballot

All but one ballot achieved a quorum, and seventeen of nineteen initial ballots received at least one negative ballot with comments, initiating the need for a recirculation ballot. The initial ballot that failed to reach quorum (Reliability Standards Development Procedure - Version 7) moved to a re-ballot that achieved quorum and was followed by a recirculation ballot. Two initial ballots received no negative ballots with comments and therefore did not require recirculation ballots: 1) BAL-006-2 and INT-003-3 (Removal of Three Midwest ISO Waivers) and 2) Interpretation of CIP-007-1, Requirement R2 for the Western Electricity Coordinating Council, which received 99.62% and 100% approval, respectively. The recirculation ballots for six initial ballots were not completed during the third quarter 2009; the drafting teams are reviewing and developing responses to ballot comments before determining the next appropriate action. All seventeen recirculation ballots that were conducted received enough affirmative votes to achieve the two-thirds weighted segment industry consensus required for approval.

No instance occurred where a proposed Reliability Standard or interpretation was disapproved by the ballot pool and thereafter a less stringent version was approved in a subsequent ballot. The discussion of the detailed ballot results for each ballot event in the third quarter 2009 is contained in **Exhibit A** to this filing.

Respectfully submitted,

/s/ *Rebecca J. Michael*

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EXHIBIT A:

Analysis of 3rd Quarter 2009 Reliability Standards Balloting Results

Introduction

On January 18, 2007, the Federal Energy Regulatory Commission ("Commission" or "FERC") issued its *Order on Compliance Filing* ("January 18 Order"),[5] acting on a compliance filing by the North American Electric Reliability Corporation ("NERC") in response to FERC's Order certifying NERC as the nation's Electric Reliability Organization ("ERO") under Section 215 of the Federal Power Act.[6] The January 18 Order requires NERC to closely monitor the voting results for reliability standards and to report to FERC quarterly for three years NERC's analysis of the voting results, including trends and patterns that may signal a need for improvement in the voting process. In its compliance filing in response to the January 18 Order, NERC stated it would file its initial quarterly report with FERC for the first quarter of 2007 and would submit subsequent quarterly filings for the next three years. This is the third quarterly report for 2009 on the analysis of voting results for reliability standards.

Background

The NERC *Reliability Standards Development Procedure* process is administered by action of the NERC Standards Committee. The Standards Committee officially approves the scope and purpose of standards authorization requests, appoints standard drafting teams to develop standards, authorizes field tests of proposed standards when necessary, and approves the proposed standards for ballot. The goal of the *Reliability Standards Development Procedure* process is to gain industry consensus on the need for, and technical sufficiency of, proposed standards. Consensus is primarily established through various formal industry comment periods designed to obtain stakeholder input on the proposed standards. However, interpretations to NERC Reliability Standards proceed directly to the ballot phase as described in the *Reliability Standards Development Procedure* without the opportunity for an industry comment period.

The members of the registered ballot body, comprising entities or individuals registered in one of ten stakeholder segments, must specifically request to be included in the ballot pool for a standard or interpretation ballot event. Any entity or interested individual may become a member of the registered ballot body, but only the ballot pool members are allowed to vote on the proposed standard or interpretation once the balloting begins. If the ballot pool approves a proposed standard or interpretation as described below, the standard or interpretation is presented to the NERC Board of Trustees for its approval and subsequent filing with FERC and applicable governmental authorities in Canada.

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[5] *Order on Compliance Filing*, 118 FERC ¶ 61,030 (2007).
[6] *North American Electric Reliability Council and North American Electric Reliability Corporation*, "Compliance Filing of the North American Electric Reliability Council and the North American Electric Reliability Corporation Addressing Non-Governance Issues," *Docket No. RR06-1-000* (October 18, 2006).

The NERC *Reliability Standards Development Procedure* provides for three different types of ballots — an initial ballot, a recirculation ballot and a re-ballot. To "pass," a ballot must achieve a quorum (at least 75% of the members of the ballot pool must return a ballot) **and** must receive an affirmative vote that is at least two-thirds of the weighted segment average of all ballots returned with a vote.

- If a ballot achieves a quorum but includes any negative ballots submitted with comments, then a recirculation ballot must be conducted.
- If a ballot does not achieve a quorum, then a re-ballot is conducted using the same ballot pool, but with an extended ballot window.

There were 37 ballots conducted during the third quarter of 2009, as shown in the table below; 19 were initial ballots, 17 were recirculation ballots, and 1 was a re-ballot. The ballots are discussed below as 17 distinct groups of "ballot events."

Ballot Event #	Ballot Name	Initial Ballot Dates	Recirculation Ballot Dates	Ballot Pool Size	Total # of Votes	Quorum	Weighted Segment Approval
1	VSLs for CIP Standards CIP-002-1 through CIP-009-1		7/7/2009 - 7/16/2009	235	218	92.77	84.96
2	Interpretation of MOD-001-1 and MOD-029-1 for the New York Independent System Operator		7/8/2009 - 7/17/2009	195	176	90.26	82.25
3	NUC-001-2 — Nuclear Plant Interface Coordination		7/10/2009 - 7/20/2009	186	162	87.10	96.94
4	Interpretation of PRC-005-1, Requirement R1 for the Compliance Monitoring Processes Working Group		7/24/2009 - 8/6/2009	274	261	95.26	95.62
5	Interpretation of TPL-002-0, Requirement R1.3.10 for PacifiCorp		7/24/2009 - 8/6/2009	217	198	91.24	98.85
6	Reliability Standards Development Procedure - Version 7	7/10/2009 – 7/22/2009		241	178	73.86	n/a
		7/27/2009 – 8/14/2009 (re-ballot)		241	204	84.65	74.79
			9/2/2009 – 9/14/2009	241	208	86.31	76.09
7	VSLs for Balancing (BAL) Standards	7/31/2009 – 8/10/2009		226	195	86.28	89.56
			8/17/2009 – 8/27/2009	226	208	92.04	89.41
	VSLs for Critical Infrastructure (CIP), Communications (COM), and	7/31/2009 – 8/10/2009		237	205	86.50	85.78
			8/17/2009 –	237	219	92.41	84.64

Ballot Event #	Ballot Name	Initial Ballot Dates	Recirculation Ballot Dates	Ballot Pool Size	Total # of Votes	Quorum	Weighted Segment Approval
	Voltage & Reactive (VAR) Standards		8/27/2009				
	VSLs for Facilities (FAC) and Modeling (MOD) Standards	7/31/2009 – 8/10/2009		232	201	86.64	87.63
			8/17/2009 – 8/27/2009	232	215	92.67	88.04
	VSLs for Interchange (INT), Personnel (PER), and Nuclear (NUC) Standards	7/31/2009 – 8/10/2009		217	186	85.71	88.63
			8/17/2009 – 8/27/2009	217	200	92.17	88.73
	VSLs for Interconnected Reliability Operations (IRO) Standards	7/31/2009 – 8/10/2009		224	193	86.16	90.15
			8/17/2009 – 8/27/2009	224	206	91.96	90.77
	VSLs for Protection and Control (PRC) Standards	7/31/2009 – 8/10/2009		234	202	86.32	88.26
			8/17/2009 – 8/27/2009	234	216	92.31	86.93
	VSLs for Transmission Operations (TOP) Standards	7/31/2009 – 8/10/2009		228	197	86.40	89.14
			8/17/2009 – 8/27/2009	228	210	92.11	88.26
	VSLs for Transmission Planning (TPL) Standards	7/31/2009 – 8/10/2009		224	192	85.71	90.46
			8/17/2009 – 8/27/2009	224	206	91.96	89.28
	VSLs for Emergency Preparedness and Operations (EOP) Standards	7/31/2009 – 8/10/2009		233	205	87.98	87.31
			8/17/2009 – 8/27/2009	233	216	92.70	85.80

Ballot Event #	Ballot Name	Initial Ballot Dates	Recirculation Ballot Dates	Ballot Pool Size	Total # of Votes	Quorum	Weighted Segment Approval
8	Interpretation of PRC-004-1 and PRC-005-1 for Y-W Electric and Tri-State	7/31/2009 – 8/10/2009		279	252	90.32	62.15
9	Interpretation of CIP-001-1 for Covanta Energy	8/6/2009 – 8/17/2009		248	210	84.68	68.92
10	Implementation Plan for CIP-002-1 through CIP-009-1 for Nuclear Power Plants (Order 706-B)	8/19/2009 – 8/28/2009		194	159	81.96	97.37
			9/1/2009 - 9/10/2009	194	169	87.11	97.18
11	Interpretation of EOP-002-2 for Brookfield Power		8/20/2009 – 8/31/2009	184	160	86.96	70.85
12	Interpretation of CIP-005-1 for PacifiCorp	8/27/2009 - 9/8/2009		248	210	84.68	80.37
13	Interpretation of CIP-006-1 for PacifiCorp	8/27/2009 - 9/8/2009		252	214	84.92	79.04
14	BAL-006-2 and INT-003-3 (Removal of Three Midwest ISO Waivers)	8/27/2009 - 9/8/2009		197	168	85.28	99.62
15	Interpretation of CIP-007-1 for the Western Electricity Coordinating Council	9/9/2009 - 9/21/2009		245	209	85.31	100
16	VSLs for CIP Standards CIP-002-2 through CIP-009-2 and the VRFs for CIP-003-2 and CIP-006-2	9/10/2009 - 9/21/2009		239	209	87.45	94.18
17	EOP-008-1 — Loss of Control Center Functionality	9/16/2009 - 9/28/2009		260	215	82.69	72.86

Discussion of Third Quarter 2009 Ballot Events

The first ballot event in the 3rd quarter of 2009 consisted of a recirculation ballot of VSLs for standards CIP-002-1 through CIP-009-1.

Standards CIP-002-1 through CIP-009-1 were originally filed with "Levels of Non-Compliance" instead of "Violation Severity Levels." FERC, in Order No. 706, approved these version 1 CIP standards and directed NERC to develop modifications to standards CIP-002-1 through CIP-009-1 to address specific concerns. Included in Order No. 706 was a directive for NERC to file VSLs for standards CIP-002-1 through CIP-009-1 before compliance audits began on July 1, 2009.

The Standards Committee authorized a shortened pre-ballot review period to help the drafting team complete the initial ballot in time to present the VSLs to the Board of Trustees for adoption and file with FERC before the July 1, 2009 deadline. NERC conducted the initial ballot for this project from June 15, 2009 through June 24, 2009, received Board of Trustees approval, and filed the VSLs for approval with FERC on June 30, 2009. The initial ballot achieved a quorum of 87.23% with a weighted affirmative approval of 83.94%.

The recirculation ballot, discussed below, was held to complete the standards development process employed by NERC. The recirculation ballot was conducted from July 7, 2009 through July 16, 2009 and achieved a quorum of 92.77% with a weighted affirmative approval of 84.96%. There were 37 negative ballots submitted for the recirculation ballot, and 26 of those ballots included a comment. Some balloters listed more than one reason for their negative ballot. Since the results of the recirculation ballot showed only a minor change in overall approval (from 83.94% in the initial ballot to 84.96% in the recirculation ballot), there are no plans to amend the filing submitted to FERC.

The reasons cited for the negative ballots included the following:

- Sixteen balloters suggested more time be allotted to developing an overall approach to VSLs, as the current approach has led to inconsistent application from one requirement to the next.
- Sixteen balloters indicated the Violation Severity Levels are unreasonably high compared to the violations, especially for minor documentation issues. The overall concern is that too great an emphasis on documents and record keeping will distract from improving the real security of Critical Cyber Assets and critical infrastructure.
- Ten balloters recommended that the drafting team evaluate and assign Violation Severity Levels at the requirement level instead of the sub-requirement level. This approach would avoid confusion regarding the compliance issues of violating only a sub-requirement and prevent double jeopardy for non-compliance.
- Two balloters indicated that many Critical Infrastructure Protection ("CIP") requirements lack what should or should not be done in order to avoid penalty, especially because many CIP requirements incorporate other standard requirements, which creates the potential for multiple violations.
- One balloter indicated any VSL changes should be made on CIP-002-2 through CIP-009-2 instead of CIP-002-1 through CIP-009-1.

The second ballot event in the 3rd quarter of 2009 consisted of a recirculation ballot for an interpretation of MOD-001-1 — Available Transmission System Capability, Requirements R2 and R8, and MOD-029-1 — Rated System Path Methodology, Requirements R5 and R6, for the New York Independent System Operator ("NYISO").

The request asks the following questions:

- Is the "advisory ATC [Available Transfer Capability]" used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of "advisory" calculations in the responsible entity's Available Transfer Capability Implementation Document?
- Could OS_F [other services] in MOD-029-1 Requirement R5 and OS_{NF} in MOD-029-1 Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?

The interpretation provided the following clarifications (summarized):

- ATC seems to be defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO's "advisory ATC" is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths. Because the second part of NYISO's question is only applicable if the first part was answered in the negative, the team did not address it.

- Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Services" would be inappropriate.

The recirculation ballot was conducted from July 8, 2009 through July 17, 2009 and achieved a quorum of 90.26% with a weighted affirmative approval of 82.25%. There were 24 negative ballots submitted for the recirculation ballot, and 15 of those ballots included a comment. Some balloters listed more than one reason for their negative ballot.

The reasons cited for the negative ballots included the following:

- All fifteen balloters who submitted a negative vote with an associated comment suggested the issue should be addressed using a method or process other than an interpretation.
    - Six balloters indicated having no opposition to the content of the interpretation but did not believe it was appropriate to append the interpretation to a continent-wide standard, since it is narrowly applied to a specific region.
    - Four balloters stated the interpretation process is being used to verify if a responsible entity process is compliant, not to clarify or correct issues with a standard.

- Six balloters stated it would be more appropriate to deal with this type of request through a regional variance or a waiver.
- Four balloters indicated NYISO should ask for a letter of no action from FERC on this issue. The balloters stated that FERC, as the entity that allowed the market design, should determine whether the "advisory" ATC calculations are actual ATC calculations. And, if not, FERC should advise the NYISO if it should perform ATC calculations.
- Three balloters indicated the interpretation of MOD-029-1 appears to be in conflict with the NYISO's tariff.

The third ballot event in the 3rd quarter of 2009 consisted of a recirculation ballot for standard NUC-001-2 — Nuclear Plant Interface Coordination.

The Nuclear Plant Interface Coordination standard requires coordination between Nuclear Plant Generator Operators and transmission entities for the purpose of ensuring safe nuclear plant operation and shutdown. The proposed revisions address two directives in FERC Order No. 716 aimed at addressing stakeholder concerns for improved clarity. Additional revisions were made to change the term "Planning Authority" to "Planning Coordinator" (to match the terminology in the latest version of the Functional Model) and to bring the compliance elements of the standard into conformance with the latest version of the ERO Rules of Procedure.

The recirculation ballot was conducted from July 10, 2009 though July 20, 2009 and achieved a quorum of 87.10% with a weighted affirmative approval of 96.94%. There were four negative ballots submitted for the recirculation ballot, and three of those ballots included a comment. Some balloters listed more than one reason for their negative ballot.

The reasons cited for the negative ballots included the following:

- One balloter indicated nuclear safety is not within the scope of NERC's responsibilities, stating the Nuclear Regulatory Commission ("NRC") has the statutory responsibility for assuring the safety of commercial nuclear power plants.
- Two balloters indicated the word "requirements" in Requirement R9.3.5 needs to be more specific to clarify what should and should not be included.
- One balloter indicated Requirement R9.3.5 is duplicative of Requirement R11.4 in EOP-005-1 and should be deleted; the balloter indicated that both requirements state that a transmission operator has to give priority to nuclear generators following the loss of off-site AC power.
- One balloter indicated the phrase "restoration process" is unclear regarding whose restoration process has to be considered: the Transmission Entity or Nuclear Plant.
- One balloter indicated it will be difficult for entities to demonstrate compliance on how they "consider" the nuclear plant's needs and urgency; the balloter suggested using the term "include," indicating that term lends itself to easier demonstration of compliance and implies more specifically that some coordination of this subject need be "included" not only in the restoration plan but also in the interface agreement to satisfy Requirement R2.

- One balloter did not agree with the proposed change from Planning Authority to Planning Coordinator. The balloter stated the term Planning Coordinator does not exist in NERC's Rule of Procedure, and NERC has not registered a single entity as a Planning Coordinator, leaving it unclear who will be responsible for the standard.
- One balloter did not support the proposed modifications of R9.3.5 due to the lack of the phrase "coping time." The balloter stated that coping time is part of a nuclear unit's licensing arrangement, and licensees are expected to have baseline assumptions, analyses, and related information used in their coping evaluations available for NRC review. The balloter indicated his company is obligated to have a specific coping time.
- One balloter indicated Requirement R9.3.5 does not provide enough clarity for the Nuclear Plant Generator Operator and Transmission Entities to develop appropriate language for the agreements required by this standard.

The fourth ballot event in the 3rd quarter of 2009 consisted of a recirculation ballot of an interpretation of PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing, Requirement R1 for the Compliance Monitoring Processes Working Group.

The Regional Entity Compliance Monitoring Processes Working Group is seeking clarification on aspects of the maintenance and testing program required for Protection Systems in Requirement R1. The request includes questions about battery chargers, relays, sensing devices, circuitry, and associated communication systems. The drafting team offered the following clarifications:

- PRC-005-1 does not require maintenance and testing of battery chargers.
- The existing definition of "Protection System" does not include auxiliary relays; therefore, maintenance and testing of such devices is not explicitly required. Maintenance and testing of such devices is addressed to the degree that an entity's maintenance and testing program for DC control circuits involves maintenance and testing of imbedded auxiliary relays. Maintenance and testing of devices that respond to quantities other than electrical quantities (for example, sudden pressure relays) are not included within Requirement R1.
- "Protective Relays" refer to devices that detect and take action for abnormal conditions. Automatic restoration of transmission lines is not a "protective" function.
- PRC-005-1 requires that entities 1) address DC control circuitry within their program, 2) have a basis for the way they address this item, and 3) execute the program. PRC-005-1 does not establish specific additional requirements relative to the scope and/or methods included within the program.
- "Associated communication systems" refer to communication systems used to convey essential Protection System tripping logic, sometimes referred to as pilot relaying or teleprotection. (Examples were included in the interpretation.)

The recirculation ballot was conducted from July 24, 2009 through August 6, 2009 and achieved a quorum of 95.26% with a weighted affirmative approval of 95.62%. There were eight negative ballots submitted for the recirculation ballot, and five of those ballots included a comment. Some balloters listed more than one reason for their negative ballot.

The reasons cited for the negative ballots included the following:

- One balloter disagreed with the response to question 5, specifically relating to digital communications systems, stating that the continuously monitored digital communications systems are not maintained and tested because the functions are embedded within the relays.
- Three balloters indicated the answers given to the question on examples of "associated communications systems" were not sufficient.
- Three balloters indicated support for including station batteries chargers under PRC-005-1, stating that battery charger failure could lead to other problems.
- One balloter indicated the drafting team did not provide sufficient clarification regarding DC control circuitry in question 4.
- Two balloters indicated disagreement with the last portion of the response to question 2: "devices that respond to quantities other than electrical quantities (for example, sudden pressure relays) are not included in R1." The balloters stated that relays/devices, such as sudden pressure relays in a major transformer and some protective relays for transformers tapped off a Bulk Power System line should be considered as part of the protection system, as they are important for ensuring reliability.
- Three balloters indicated the team interpreted the language of the standard too strictly and should have considered the intent of the original standard. One balloter stated the proper approach would be to assume the "but not limited to" language was never removed from the definition when the Version 0 standards were developed. Two balloters stated the strict interpretation runs counter to the purpose of the standards, *i.e.*, ensuring reliability.
- One balloter commented that the interpretation should not redefine the meaning of the standard.

The fifth ballot event in the 3rd quarter of 2009 consisted of a recirculation ballot for an interpretation of TPL-002-0 — System Performance Following Loss of a Single Bulk Electric System Element (Category B), Requirement R1.3.10 for PacifiCorp.

PacifiCorp requested clarification for the following items:

- "Does TPL-002-0 R1.3.10 require that all elements that are expected to be removed from service through normal operation of the protection systems be removed in simulations? "
- "Is a Category B disturbance limited to faults with normal clearing where the protection system operates as designed in the time expected with proper functioning of the protection system(s) or do Category B disturbances extend to protection system [misoperations] and failures?"
- "Does TPL-002-0 R1.3.10 require that planning for Category B contingencies assume a contingency that results in something other than a normal clearing event even though the TPL-002-0 Table I — Category B matrix uses the phrase 'SLG or 3-Phase Fault, with Normal Clearing'?"

The interpretation provided the following clarifications:

- TPL-002-0 requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a, Requirement R1.3.10

does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.

- This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).
- TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line to Ground ("SLG") or 3-Phase (3Ø) Fault on the performance of the Transmission System

The recirculation ballot was conducted from July 24, 2009 through August 6, 2009 and achieved a quorum of 91.24% with a weighted affirmative approval of 98.85%. There were four negative ballots submitted for the recirculation ballot, and one of those ballots included a comment.

The reason cited for the negative ballot referenced support for the comments of Duke Energy, which voted affirmative but offered suggestions for further guidance related to "Normal Clearing." Duke references support for the standards authorization request ("SAR") for Project 2009-07: Reliability of Protection Systems. The SAR for the project proposes a standard requiring facility owners to have protection system equipment installed such that, if there were a failure of a specified component of that protection system, the failure would not prevent meeting the bulk electric system performance identified in the TPL standards. A number of balloters who voted affirmative explained they agreed with the interpretation but referenced support for the Duke comments.

The sixth ballot event in the 3rd quarter of 2009 consisted of an initial and recirculation ballot for the revised version of the *Reliability Standards Development Procedure, Version 6.1* manual.

The *Reliability Standards Development Procedure, Version 6.1* contains the procedures governing the standards development process. During recent NERC Board of Trustees meetings, the board took actions that require conforming modifications to the *Reliability Standards Development Procedure*:

- In February 2008, the board acted to dissolve the NERC-NAESB Joint Interface Committee.
- In October 2008, the board directed the Standards Committee to modify the standards development process to address standards developed in response to national security emergency situations.
- In February 2009, the board directed the Standards Committee to change the standards development process regarding the way VRFs and VSLs are developed and approved. The changes replaced stakeholder approval of VRFs and VSLs with a stakeholder straw poll, and granted the NERC Board of Trustees the responsibility for approving VRFs and VSLs, giving consideration to the results of the straw poll. These modifications were proposed by the board's Corporate Governance and Human Resources committee after posting its proposal for stakeholder comment.

The initial ballot was conducted from July 10, 2009 through July 22, 2009 and failed to reach quorum. A re-ballot was conducted from July 27, 2009 through August 14, 2009 and achieved a quorum of 84.65% with a weighted affirmative approval of 74.79%. There were 50 negative ballots submitted for the re-ballot ballot, and 34 of those ballots included a comment, which initiated the need for a recirculation ballot. The recirculation ballot was conducted from September 2, 2009 through September 14, 2009 and achieved a quorum of 86.31% with a weighted affirmative approval of 76.09%. There were 52 negative ballots submitted for the recirculation ballot, and 33 of those ballots included a comment.

The reasons cited for the negative ballots included the following:

- Twenty seven balloters indicated they do not agree with removing either VRFs or VSLs or both from the standards development process, stating these elements should remain subject to industry vetting and approval. Fourteen balloters referenced both elements, while seven singled out VRFs and six singled out VSLs. Some balloters indicated that VSLs are appropriately part of the compliance process; therefore, the proposed process of separate ballots is acceptable. Reasons listed for keeping these elements as part of the process included the following:
    - VRFs are a reliability related part of the standard representing the impact a requirement has on the Bulk Power System.
    - VRFs and VSLs are technical elements; given the complexity and interrelationships of the hundreds of requirements, an appropriate determination of VRFs and VSLs is dependent on the expert knowledge and experience of industry personnel.
    - Comments submitted by stakeholders and the results of the proposed "non-binding poll" may not have the same effect as a direct ballot and removes critical oversight of VSLs. The NERC staff role should include presenting dissenting views and concerns to the Board of Trustees but should not include developing VRFs and VSLs.
    - VRFs could be set too high if stakeholder concerns are not adequately addressed in the comment phase.
    - If they are voted on separately, VRFs and VSLs may not be maintained with the standard, leading to possible version mismatches and difficultly finding the appropriate information.
    - Industry approval is the only method to ensure VSLs do not inadvertently impose additional requirements and do reflect achievable performance.
- Nine balloters indicated they did not support, in one or more ways, the additions to the process regarding national security emergency situations.
    - One balloter suggested this is not a standard development issue but a communication and coordination issue, stating that FERC, the DOE (Department of Energy), NERC and the Regional Entities already have tools in place to selectively notify the electric industry of threats and coordinate solutions.
    - One balloter indicated the Special Procedures section is unclear. The balloter indicated it would be beneficial to combine the sections dealing with confidential issues – "Standards to Support Issues that are Confidential" and "Emergency Action Process for Standards Responsive to Imminent Issues that are Confidential" – because the separation of these related sections and small language differences create confusion.

    - Three balloters indicated there should not be a need for a special confidential process, suggesting it would likely to be too slow to accommodate true "national emergencies." The balloters believe the government needs to find an alternative way to address national emergencies and stated that NERC is not the appropriate forum for this type of activity.
    - Four balloters indicated that NERC and the electric industry are not prepared to develop, approve, implement, or (possibly) comply with "confidential" standards or "confidential" emergency actions. The balloters suggested removing the confidential process until NERC and the electric utility industry could develop a proper structure and infrastructure for this type of activity; the balloters listed a number of suggested requirements for the process.
- Three balloters listed items that seemed unrelated to the ballot. Two voiced concern over "too many standards and requirements" and the time it currently takes to draft a standard. Another balloter suggested assigning and voting on VSLs on a requirement-by-requirement basis.

The seventh ballot event in the 3rd quarter of 2009 consisted of initial and recirculation ballots for nine sets of VSLs.

The ballots resulted from two projects that focused on VSL development:

1. **Project 2007-23:** In its June 19, 2008 VSL Order, FERC directed NERC to review all VSL assignments, with the exception of those for which FERC directed specific modification, for compliance with the following Guidelines 2b, 3 and 4 and submit a compliance filing either validating the current VSL assignments or proposing revision.
    - Guideline 2b — VSLs should not use ambiguous terms such as "minor" or "significant" to describe noncompliant performance.
    - Guideline 3 — VSLs should be consistent with the corresponding requirement (VSLs should not expand on what is in the requirement).
    - Guideline 4 — VSLs should be based on a single violation, not on a cumulative number of violations (unless stated otherwise in the requirement).

   The project addressed VSLs for the following standards families (grouped by ballot):
    - Resource and Demand Balancing ("BAL")
    - Critical Infrastructure Protection ("CIP"), Communications ("COM"), and Voltage & Reactive ("VAR")
    - Facilities Design, Connections, and Maintenance ("FAC") and Modeling, Data, and Analysis ("MOD")
    - Interchange Scheduling and Coordinating ("INT"), Personnel Performance, Training, and Qualifications ("PER"), and Nuclear (NUC)
    - Interconnected Reliability Operations and Coordination ("IRO")
    - Protection and Control ("PRC")
    - Transmission Operations ("TOP")
    - Transmission Planning ("TPL")
2. **Project 2008-08:** The ballot for the VSLs for the eight Emergency Preparedness and Operations ("EOP") reliability standards that was conducted in 2008 failed to meet the required two-thirds affirmative majority of the weighted segment votes cast. As a result,

the NERC Board of Trustees directed the Standards Committee to take the necessary steps needed to expedite the development of a revised group of EOP VSLs for filing with FERC.

The initial ballots for the nine sets of VSLs were conducted from July 31, 2009 through August 10, 2009. Each initial ballot contained at lease one negative vote with an associated comment, which initiated the need for recirculation ballots. The recirculation ballots were conducted from August 17, 2009 through August 27, 2009. The ballots results are displayed in the following table:

VSL Ballot (by standard types)	Initial		Recirculation	
	Quorum (%)	Approval (%)	Quorum (%)	Approval (%)
Resource and Demand Balancing (BAL)	86.28	89.56	92.04	89.41
Critical Infrastructure Protection (CIP), Communications (COM), and Voltage & Reactive (VAR)	86.50	85.78	92.41	84.64
Facilities Design, Connections, and Maintenance (FAC) and Modeling, Data, and Analysis (MOD)	86.64	87.63	92.67	88.04
Interchange Scheduling and Coordinating (INT), Personnel Performance, Training, and Qualifications (PER), and Nuclear (NUC)	85.71	88.63	92.17	88.73
Interconnected Reliability Operations and Coordination (IRO)	86.16	90.15	91.96	90.77
Protection and Control (PRC)	86.32	88.26	92.31	86.93
Transmission Operations (TOP)	86.40	89.14	92.11	88.26
Transmission Planning (TPL)	85.71	90.46	91.96	89.28
Emergency Preparedness and Operations (EOP)	87.98	87.31	92.70	85.80

The reasons cited for the negative ballots can be grouped into eight categories:

1. Concerns with language and VSL consistency with requirements
2. Risk versus severity
3. Did not support binary approach
4. VSLs should be balloted by requirement
5. Changes not consistent with guidelines 2b, 3 and 4
6. Could create double jeopardy for compliance
7. Punitive to smaller entities
8. Discriminatory to Balancing Authorities

The following table displays the number of ballots with negative comments grouped by reason for and standard family. A more detailed description of the voter concerns follows the table.

Number of Negative Comments for VSLs by and Reason and Standard Family

Reason	Standard Family								
	BAL	CIP, COM, VAR	FAC, MOD	INT, PER, NUC	IRO	PRC	TOP	TPL	EOP
1. Language and VSL consistency with requirements	1	10	4	9		5	4	1	4
2. Risk versus severity	2		3			2		3	4
3. Binary approach opposition	6	5	4	5	5	5	4	4	5
4. VSL balloting approach opposition	4	4	4	4	4	4	4	4	4
5. Guidelines 2b, 3 and 4 consistency	1			1	1		1		
6. Double jeopardy for compliance	4				4	4			
7. Punitive to smaller entities	1	2							6
8. Discriminatory to Balancing Authorities	4								

1. **Language and VSL consistency with requirements:** Thirty eight balloters indicated concerns with the clarity of the VSL language, the consistency of the VSLs with the requirements, or both. At a general level, one balloter indicated the revised VSLs still apply to requirements that remain vague and ambiguous. Specific concerns included the following:

Standard	Req.	Concern
BAL-001-0	R1	To be enforceable, the VSL needs to be more detailed or the NERC glossary definition of Disturbance needs to be revised.
BAL-003-0	R2	Low VSL is not correct because by Requirement R5 the Balancing Authority’s determination of its fixed frequency bias can be 1% of estimated load if supplying native load or 1% of maximum generation if not. The lower VSL as stated would imply that a Balancing Authority using a bias as required by Requirement R5 would be in violation.
BAL-003-0	R3	VSLs will be difficult to measure. The measure needs to be revised before assigning the VSL.
BAL-004-0	R4	This is the authority of the Reliability Coordinator to terminate a Time Error if the Reliability Coordinator feels the Time Error is a contributor to actual or potential reliability issues for the interconnection. The Reliability Coordinator should not be subject to a severe VSL if a Time Error was not curtailed.
BAL-005-0	R6	The language in the high VSL needs to be the same as that in the moderate VSL; that is, “failed to use the ACE calculation ...” needs to be “failed to calculate ACE as specified in the requirement”
BAL-005-0	R7	Revisit whether this should be a severe VSL and consider splitting the two “or” statements to separate VSLs.
BAL-005-0	R9	Requirement does not state how long the schedule is not included and needs to be better defined and include a measure before a VSL is assigned.
BAL-006-1	R4	With the “or” statement in the moderate VSL, the lower VSL and moderate VSL are now the same.
COM-001-1	R4	Does not require a written agreement to use English; it requires an agreement to use anything other than English.
EOP-003-1	R7	Unclear how the base number of “automatic actions” is determined for use in calculating percentages used in the VSLs. A better definition of “automatic actions” is needed or the percentage approach should not be used.
FAC-001-0	R1	Moderate VSL should say "failed to include" not "Include"

Standard	Req.	Concern
FAC-002-0, FAC-008-1		The word assessment makes no sense.
FAC-003-1	R1	New draft is more ambiguous than in the current VSL matrix. The new language only identifies the lack of updates or "changes" to the document.
FAC-003-1	R1.5	Severe VSL uses OR when the requirement used AND. Lack of documentation should be a severe violation; OR is not consistent with the requirement.
FAC-003-1	R3, R4	Lower VSL requires a report even if entity did not have a reportable outage, which is beyond what is in the requirement. The VSL cannot make a requirement to report.
FAC-008-1	R1	Lower and moderate VSLs do not indicate what assessment is meant. The requirement refers to documenting its methodology and what the methodology should include, not an assessment.
FAC-009-1		Percentages are too low; schedules are undefined
FAC-013-1	R1	Lower VSL does not make sense; it seems to have an extra phrase, "but one or more Transfer Capabilities."
FAC-013-1	R2.1, R2.2	Really defining who has the "reliability related need," so they should be rolled up into R2.
INT-010-0	R1	Revised VSLs for are graduated to the tardiness of the action, which seems less important than the discrete number of times Requirement R1 was not met (original VSLs).
MOD-006-0		Need to have exemption language in the VSL for having no CBM (Capacity Benefit Margin).
MOD-010-0, MOD-012-0		How does the compliance monitor know what corresponds to each percentage range when that is not spelled out anywhere?
PER-002-0	R1	Proposed VSLs are confusing and unclear on what is being assessed.
PER-002-0	R2	Proposed VSLs are not consistent with the language of R2, which requires the Transmission Owner and Balancing Authority to have a training program for certain operating personnel. The requirement says nothing about the implementation or administration of the training program, which is the basis for the proposed VSL.
VAR-001-1	R3.1	Proposed VSLs will be difficult to apply unless a large number of generators are exempt. The 5% increments are too narrow to be meaningful. The double criteria within the VSLs could pose an application problem – single criteria (discrete number or percentage) would be sufficient.
VAR-001-1	R6.1	Conditioned upon notification to the Transmission Owner of the loss of an automatic voltage control regulator; notification condition needs to be reflected in the proposed VSLs.
VAR-002-1	R1	Severe VSL is too open to interpretation; prefer old wording, which has a discrete 75% value.
VAR-002-1	R2	Lower VSL: 5% or less can be interpreted to be any deviation, including the tolerance of measuring equipment.
VAR-002-1	R3	High and severe VSLs are the same and are the same as the original lower.
VAR-002-1	R5	Severe VSL is restrictive.

2. **Risk versus severity**: Fourteen balloters indicated concerns about severity level assignments that seemed out of balance with a violation's risk or impact to the reliability of the system. One balloter specifically indicated disagreement with the drafting team's assertion that risk is completely separate from severity. Another balloter stated that due to suggestions for NERC to move away from concentrating on documentation violations, raising the VSL for a documentation error would seem counter to the long-term goals of the organization.

A number of balloters pointed out standard-specific issues:

Standard	Req.	Concern
BAL-003-0	R3.	Not operating AGC to Tie Line Frequency Bias should not be a severe VSL. For example, if a Balancing Authority was operating only to tie-line bias, the frequency bias obligation is usually small, especially during normal operations when frequency is near or equal to 60 Hz
BAL-003-0	R5	Suggest VSL be lowered to moderate or high from severe. The error to the ACE equation would only come from the frequency bias obligation, which is normally small, and should not have a "severe" impact to the reliability of the interconnection.
BAL-004-0	R1	Requirement R1 is not a requirement but a statement; the VSL should be removed. If this is a severe VSL, the only responsible entity that could be affected is the NERC Operating Committee.
BAL-004-0	R2	Proposed severe VSL is problematic. After reviewing the NAESB business practice, WEQBPS-004-000 it is not clear that corrective actions orders are so defined other than the thresholds of when Time Error should be initiated and when Time Error should be terminated.
BAL standards		The designated Time Error monitor for the interconnection could be held in violation and this would discourage those who might accept the role as monitors. Initiating Time Error, especially for fast time correction, can actually reduce the reliability of the interconnection by making it more prone to frequency deviations greater than 50 Hz. Suggest this VSL be moved to lower or moderate.
EOP standards		Consideration might be given to the significance of the required entities requiring coordination of plans rather than strictly the number of required entities
FAC-001-0 FAC-002-0 FAC-008-0 FAC-009-1 FAC-013-1 MOD-010-0 MOD-012-0 TPL-001-0 TPL-002-0 TPL-003-0 TPL-004-0		Do not agree with many of the severe VSLs assigned to certain requirements in standards. These standards are system planning standards, and as such the reliability of the system will not be jeopardized if many of these standard requirements are not met. A VSL of severe should be reserved for situations where a requirement violation directly jeopardizes the reliability of the system, such as for situations where rating data is not provided (i.e., a violation of FAC-008 Requirements R6 and R7). The critical issue is that planners and operators of the electric system have rating data. Failure to make a Facility Ratings Methodology document available for inspection (a violation of R3) does not jeopardize the reliability of the system.
PRC-005	R1	A no impact situation should likewise carry no severity

3. **Binary approach opposition**: In accordance with FERC Guideline 2, to provide consistency in the VSL assignments for binary requirements, the VSL drafting team revised the VSLs for some requirements to assign binary VSLs at the severe category level. Forty three balloters did not support this approach. The balloters indicated binary violations are not severe and should not be categorized as such. The balloters stated the heart of the problem is the discontinuity between the binary measures and the variable compliance penalty matrix. The balloters claimed the resolution is to revise the measures in the standard through the standards development process to resolve the discontinuity.

4. **Opposition to VSL balloting approach**: Thirty six balloters stated that the VSLs for each standard should have been balloted individually instead of in the current sets. The main concern was that the bundling of VSLs with a single "up or down" vote applying to all VSLs in a group creates a situation where acceptable VSLS are needlessly rejected. In instances where the majority of the VSLs are acceptable, an entity is forced to vote down all the VSLs because of the one problematic VSL.

5. **Guidelines 2b, 3 and 4 consistency:** A few balloters indicated they did not believe the VSL changes were consistent with guidelines 2b, 3 and 4 given by FERC and NERC for this project.
6. **Double jeopardy for compliance:** Twelve balloters indicated the VSLs increase the likelihood that entities will be at risk of double jeopardy for compliance. Balloters indicated potential risks within the proposed VSLs for the PER and IRO families of standards. Four balloters listed the example of the VSLs for IRO-006-3, Requirement R6 that references non-compliance with INT standards; the balloters were concerned the linkage could result in double jeopardy.
7. **Punitive to smaller entities:** Nine balloters indicated the use of a percentage system to "maintain consistency" between standards makes for unequal treatment of substantially similar facilities. For example, a generator with seven assets would be guilty of a severe violation for failure to ensure one was within a metered area, but a generator with eight assets would be guilty of a high violation. Balloters also listed the following examples:
    a. In the VAR standards and in EOP-009-1, Requirement R1, a smaller entity with four generators (blackstart generators for EOP-009) would go from compliant to a severe VSL with one generator missing the requirement.
    b. The 5% increments used in EOP-003-1, Requirement R3, dealing with coordination of load shedding plans with its required entities, are not always suitable, especially in cases when there are only one or two required entities.
8. **Discriminatory to Balancing Authorities:** Four balloters indicated BAL-002-0, Requirements R1.1 and R2 are unnecessarily discriminatory against Balancing Authorities that participate in a Reserve Sharing Group and could actually discourage participation.

The eighth ballot event in the 3rd quarter of 2009 consisted of an initial ballot for an interpretation of standards PRC-004-1 — Analysis and Mitigation of Transmission and Generation Protection System Misoperations and PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing for Y-W Electric Association, Inc. and Tri-State Generation and Transmission Association, Inc..

Y-W Electric Association, Inc. (Y-WEA) and Tri-State Generation and Transmission Association, Inc. (Tri-State) requested an interpretation of the term "transmission Protection System" and specifically whether protection for a radially-connected transformer protection system energized from the BES is considered a transmission Protection System and is subject to these standards.

The drafting team prepared the following response:

The request for interpretation of PRC-004-1, Requirements R1 and R3 and PRC-005-1, Requirements R1 and R2 focuses on the applicability of the term “transmission Protection System.” The NERC *Glossary of Terms Used in Reliability Standards* contains a definition of “Protection System” but does not contain a definition of transmission Protection System. The term transmission Protection System is applicable to any Protection System that is designed to detect and initiate action for system faults on transmission elements (lines, buses, transformers, *etc.*) identified as being included in the BES.

In general, a radially connected transformer protection system energized from the BES would not be considered a transmission Protection System. In the event that the transformer low side is connected to a potential source (generator or networked low side system) and there are Protection Systems installed to detect and initiate actions for transmission system faults, then these Protection Systems would be considered transmission Protection Systems.

It should also be noted that due to the variance in the Regional Entity definitions of the BES, specific clarification may be required from the appropriate Regional Entity.

The initial ballot was conducted from July 31, 2009 through August 10, 2009 and achieved a quorum of 90.32% with a weighted affirmative approval of 62.15%. There were 97 negative ballots submitted for the initial ballot, and 75 of those ballots included a comment, which initiated the need for a recirculation ballot. Some balloters listed more than one reason for their negative ballot.

The reasons cited for the negative ballots included the following:

- Nineteen balloters indicated the interpretation appears to “define” transmission Protection System, which is inconsistent with the *Reliability Standards Development Procedure* (interpretations may not be used for this purpose).
- Twenty balloters had concerns about the variance in the Regional Entity definitions of the BES:
    - Ten balloters indicated the last sentence removes the clarity provided by the first two paragraphs. Two balloters stated the sentence gives the Regional Entity room to reject or modify the interpretation through “specific clarifications” in regard to the interpretation.
    - Four balloters indicated the variance in Regional Entity definitions of the BES should be eliminated by NERC, especially since there are entities that span multiple regions.
    - Six balloters indicated this interpretation is in conflict with some of the Regional Entities, such as *Reliability*First Corporation.
    - One balloter requested clarification for whether the Regional Entity definition of the BES must be formally approved by FERC or NERC or if it can be defined informally.
    - One balloter indicated the interpretation did not address the disparity between the two Regional Entity examples given.
- Sixty seven balloters indicated the interpretation lacked clarity regarding the classification of system elements:
    - Seventeen balloters indicated the term “the networked low side system” is too general and suggested excluding the following from being considered as transmission Protection Systems: a) networks serving only load from one transmission source, including radial transmission facilities with normally open secondary sources and b) weak loops operated at voltages below 200 kV (loops connected to the BES that provide redundancy to serve distribution but are not intended to and do not provide ‘meaningful’ flow-through capability).

- Seventeen balloters indicated a Protection System for a transformer should only be considered a transmission Protection System if it is also be capable of clearing a high-current fault on the transmission side of the transformer, not just limited fault conditions from inside the transformer or on the low-side bus.
- Twenty seven balloters indicated the language regarding a "potential source," especially regarding the size, needs further clarification. Three of those balloters indicated the language could lead to small potential sources to "the transformer low side" being part of a transmission Protection System. Seventeen of those balloters indicated that PRC-004-1 and PRC-005-1 should only apply to a facility within a distribution system that connects a generator that meets NERC's registration criteria for Generator Owner (currently, 20 MVA for a single unit and 75 MVA for aggregate units). "We have chosen to reference the registration criterion, rather than the specific values, so that if thresholds change in the future this criterion would continue to consistent."
- Eight balloters indicated the phrase "designed to detect and initiate action for" in the interpretation response seems to blur the distinction between a transmission Protection System and a Special Protection System. The balloters stated that in general, non-BES equipment that does not initiate BES equipment action, or has no effect on the BES, should not be considered part of a transmission Protection System.
- Eight balloters indicated the interpretation appears to be applicable to a particular circumstance of a protection system; if adopted, this interpretation may result in numerous interpretation requests for other system configurations and protection designs.
- One balloter indicated the second paragraph may not have addressed all possible scenarios and exceptions, potentially leading to more questions.
- Three balloters indicated clarification is needed regarding the classification of non-BES Protection Systems that are designed to protect the BES against uncleared faults on non-BES elements that could impact the BES.
- Five balloters indicated the interpretation did not provide sufficient clarification as to which equipment falls inside the BES and the PRC-004 and PRC-005 requirements.
- One balloter disagreed that having a source on the radial system makes it a protection system.
- One balloter indicated that not mentioning the BES specifically in the language regarding radially connected transformer protection systems could lead to inconsistencies in the application of these standards by the Regional Entities.
- Three balloters indicated that while they understood the request specifically addressed transformer protection on radial transmission lines, they do not believe that a narrow interpretation is in the best interests of the industry. The balloters suggested the term "transmission Protection System" should be applicable to any Protection System that is designed to detect and initiate action for faults on transmission elements (lines, transformers, breakers, *etc*.) identified as being included in the BES.

- Three balloters indicated that the mention of "networked low side system" seems beyond the scope of the standards, potentially extending the transmission bulk electric system protective elements down to 15/69 kV transformers and 69 kV lines with relay elements that could possibly extend onto the high side of the transformers as backup protection.
- One balloter indicated voting no "because a failure to trip the low side distribution breakers will require that the high side breaker trips. Failure to do so may cause the BES breakers supplying the substation in question to trip."
- One balloter indicated the protection system for a transformer with a high side voltage greater than 100 kV, connected to a transmission line at greater than 100 kV by a tap, should be considered a BES protection system if 1) the transformer tap connection had two power supplies or 2) the transformer protection system had direct communication with another BES relay or protection system such as a transfer trip system.
- Four balloters indicated protective relays (differential and over-current) for transformers tapped off a Bulk Electric System line should be included under PRC-005 and PRC-004, stating the relays protecting the transformer are just as important as the relays protecting the BES facility.

The ninth ballot event in the 3rd quarter of 2009 consisted of an initial ballot for an interpretation of standard CIP-001-1 — Sabotage Reporting, Requirement R2 for Covanta Energy.

Covanta Energy requested an interpretation of the term "appropriate parties" and asked if there is an entity within the Interconnection hierarchy that deems parties to be appropriate.

The drafting team offered the following clarifications:

- The drafting team interprets the phrase "appropriate parties in the Interconnection" to refer collectively to entities with whom the reporting party has responsibilities and/or obligations for the communication of physical or cyber security event information. For example, reporting responsibilities result from NERC standards IRO-001 Reliability Coordination — Responsibilities and Authorities, COM-002-2 Communication and Coordination, and TOP-001 Reliability Responsibilities and Authorities, among others. Obligations to report could also result from agreements, processes, or procedures with other parties, such as may be found in operating agreements and interconnection agreements.
- The drafting team asserts that those entities to which communicating sabotage events is appropriate would be identified by the reporting entity and documented within the procedure required in CIP-001-1 Requirement R2.
- Regarding "who within the Interconnection hierarchy deems parties to be appropriate," the drafting team knows of no interconnection authority that has such a role.

The initial ballot was conducted from August 6, 2009 through August 17, 2009 and achieved a quorum of 84.68% with a weighted affirmative approval of 68.92%. There were 58 negative ballots submitted for the initial ballot, and 42 of those ballots included a comment, which initiated the need for a recirculation ballot. Some balloters listed more than one reason for their negative ballot.

The reasons cited for the negative ballots included the following:

- Ten balloters indicated concerns with the references to other standards:
  - Four balloters indicated IRO-001 and TOP-001 have nothing to do with sabotage reporting and claim that citing them in this way is an indirect interpretation of those two standards and therefore falls outside the ANSI-accredited process. The balloters indicated COM-002 is only marginally relevant.
  - Four balloters indicated the references to IRO-001, COM-002-2, and TOP-001 only add confusion and believe the interpretation process should just answer the question asked and not elaborate with further discussion.
  - One balloter indicated the reference to COM-002 as an example does not help; it uses "appropriate" to describe the entities that need to be communicated to, so it has the same problem.
  - One balloter indicated the example standards say nothing regarding the reporting of physical or cyber security events.
- Twenty six balloters indicated concerns regarding the notification of parties for sabotage events:
  - Two balloters indicated Requirement R2 of CIP-001-1 is limited to requiring that the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator and Load-Serving Entity have procedures in place for the communication of information concerning sabotage events.
  - Eight balloters indicated the reference to obligations arising from "agreements, processes and procedures" may be overly inclusive and may encompass contractual or other obligations that are not related to grid reliability.
  - Ten balloters indicated the reference to obligations arising from "agreements, processes and procedures" may fail to include parties that perform one or more reliability functions.
  - Two balloters indicated the list of entities should not be considered to be required as auditable evidence in a compliance audit.
  - Six balloters indicated the reference to obligations arising from "agreements, processes, and procedures" is too broad or still undefined.
  - One balloter indicated the interpretation should simply state that the drafting team asserts that those entities to which communicating sabotage events is appropriate would be identified by the reporting entity and documented within the procedure required in CIP-001-1.
  - Nine balloters indicated either Requirement R2 does not necessitate specific "appropriate entities" to be identified in the procedures or that it should be left to the responsible entity to define the appropriate parties. Most of those balloters stated the list should be determined by the incident and potential impact.

- Two balloters indicated the notification should be made to the appropriate Reliability Coordinator; one suggested the Reliability Coordinator could cascade the message to other Reliability Coordinators in North America.
  - One balloter indicated the background agreements from which the entities created their lists will not be reviewed during a compliance audit, which will result in an audit simply confirming that the entity has a list for a requirement (R2) that requires an entity have a procedure.
  - One balloter indicated the first part of the interpretation is vague as it implies that the list of these entities should result from requirements of the other standards.
  - One balloter indicated the interpretation needs to be more specific regarding the parties to be communicated with since significant doubt would remain as to whether or not the required communication processes have been established with all necessary parties; the balloter recommended Requirement R2 be revised to explicitly identify parties when CIP-001 is due for its next revision.
  - One balloter indicated "appropriate entities" should be those organizations that need to know given the event and the circumstances. Within an Interconnection, the entities that should be made aware of the event are the Registered Entity's Reliability Coordinator and/or Transmission Provider(s).
  - Four balloters indicated the interpretation still leaves open to debate between auditors and responsible entities the issue of whether the responsible entity identified appropriate interconnection parties.
  - One balloter indicated the third paragraph conflicts with the second. The third says the drafting team knows of no Interconnection authority who deems the parties that are appropriate, but the second says the registered entity must identify the appropriate parties, meaning the registered entity has the authority.
  - Two balloters indicated phrases such as "appropriate parties" are ambiguous and would interfere with an auditor’s objective audit and could require an auditor (and a registered entity’s contracts department) to review every entity contract. This could potentially increase the need for resources for Regional Entities and registered entities with little or no benefit to the reliability of the BES.
  - One balloter indicated the response references reporting to entities requiring physical or cyber security event information, but this standard is focused on sabotage.
- Eight balloters indicated general clarification is needed, saying either the interpretation is too vague or does not help with the compliance for vague requirements.
- Two balloters indicated the phrase “…those entities to which communication sabotage events is appropriate would be identified by the reporting entity and documented within the procedure required in CIP-001-1 Requirement R2" seems to mean that as long as the reporting entity does what its procedure states then it is in compliance. The balloters claim the purpose of the standards should not only ensure that reporting entities do what they state they will do but that they will perform in accordance with the requirement to maintain an acceptable level of reliability.

The tenth ballot event in the 3rd quarter of 2009 consisted of an initial and recirculation ballot for an implementation plan for Version 1 CIP Reliability Standards CIP-002-1 through CIP-009-1 for nuclear power plants.

On January 18, 2008, FERC issued Order No. 706 that approved Version 1 of the CIP standards: CIP-002-1 through CIP-009-1. On March 19, 2009, FERC issued Order No. 706-B that clarified "the facilities within a nuclear generation plant in the United States that are not regulated by the U.S. Nuclear Regulatory Commission are subject to compliance with the eight mandatory 'CIP' Reliability Standards approved in Commission Order No. 706." However, in the ensuing discussion regarding the implementation timeframe for the nuclear power plants to comply with the CIP standards, FERC noted in PP 59 and 60 that:

> it is not appropriate to dictate the schedule contained in Table 3 of NERC's Implementation Plan, i.e., a December 2010 deadline for auditable compliance, for nuclear power plants to comply with the CIP Reliability Standards. Instead of requiring nuclear power plants to implement the CIP Reliability Standards on a fixed schedule at this time, we agree to allow more flexibility.
>
> Rather than the Commission setting an implementation schedule, we agree with commenters that the ERO should develop an appropriate schedule after providing for stakeholder input. Accordingly, we direct the ERO to engage in a stakeholder process to develop a more appropriate timeframe for nuclear power plants' full compliance with CIP Reliability Standards. Further, we direct NERC to submit, within 180 days of the date of issuance of this order, a compliance filing that sets forth a proposed implementation schedule.

This project addresses the development of the implementation plan specifically for nuclear power plants. The plan was drafted by members of the original Version 1 Cyber Security Drafting Team with specific outreach to nuclear power plant owners and operators to ensure their interests were fairly represented.

The initial ballot was conducted from August 19, 2009 through August 28, 2009 and achieved a quorum of 81.96% with a weighted affirmative approval of 97.37%. There were four negative ballots submitted for the initial ballot, and one of those ballots included a comment, which initiated the need for a recirculation ballot. The recirculation ballot was conducted from September 1, 2009 through September 10, 2009 and achieved a quorum of 87.11% with a weighted affirmative approval of 97.18%. There were five negative ballots submitted for the recirculation ballot, and one of those ballots included a comment.

The reason cited for the negative ballot related to the implementation timeframe. The balloter indicated that additional consideration should be given to nuclear power plants for the development and implementation of a cyber security program that is fully compliant to the CIP standards, which would involve a more thorough vetting of the exemption process and of the implementation timeframes that support design changes and nuclear refueling outage planning windows. The balloter stated the implementation timeframe is crucial for allowing adequate time to develop and implement design changes, procedural instructions and training.

The eleventh ballot event in the 3rd quarter of 2009 consisted of a recirculation ballot for a revised interpretation of EOP-002-2 — Capacity and Energy Emergencies, Requirements R6.3 and R7.1 for Brookfield Power.

The request asked for confirmation that Requirement R6.3 requires the curtailment of only non-firm exports when interruptible load is curtailed, while Requirement R7.1 requires the curtailment of firm exports when firm load is curtailed. Brookfield Power cited Reliability Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief (TLR) as the basis for its interpretation of EOP-002-2 Requirement R7.1.

An initial interpretation was balloted from June 2, 2008 through June 11, 2008, and several stakeholders indicated the interpretation needed additional clarification. Although the initial ballot achieved a weighted segment approval of 76.47%, the drafting team modified the interpretation to improve its clarity, including the language regarding the treatment of wheel-through transactions. The revised interpretation clarified that, when considering actions to be taken to comply with EOP-002-2 R6.3, it is intended that all exports, firm and non-firm, are available for curtailment with the exception of those exports designated as network resources for an external Balancing Authority. If a capacity or energy emergency still exists after all exports have been curtailed, with the exception of those related to a network resource designated to an external Balancing Authority, then EOP-002-2 Requirement R7.1 would take effect and firm load would be shed while the designated network resource transaction would continue to flow. Requirement R7.1 speaks only to the need to manage area control error and is not tied to the curtailment of export transactions as identified in IRO-006-4. The initial ballot, which failed to reach a quorum, and subsequent re-ballot for the revised interpretation were conducted in the fourth quarter of 2008.

The recirculation ballot for the revised interpretation was conducted from August 20, 2009 through August 31, 2009 and achieved a quorum of 86.96% with a weighted affirmative approval of 70.85%. There were 45 negative ballots submitted, and 31 of those ballots included a comment. Several balloters listed more than one reason for their negative ballot.

The reasons cited for the negative ballots included the following:

- Twenty three balloters indicated concern with (or did not support) limiting a Balancing Authority's curtailment options during an emergency. Most of those balloters stated there are too many variables and circumstances to consider to determine the best course of action during an energy or capacity emergency to mandate shedding firm load before curtailing an export (as the interpretation suggests). Many also stated that a "source" Balancing Authority does not necessarily know which exported resources are designated as network resources in the "sink" Balancing Authority area. Some of the balloters offered suggestions on addressing the issue:
    - Modify the e-tag specifications (INT standards) to include an identifier for designated resources to enable the source Balancing Authority to be able to determine which transaction could be curtailed.
    - Modify the interpretation to indicate that the Balancing Authority with the energy shortage should take appropriate actions for the situation, in conjunction with the Reliability Coordinator, without causing interconnection-wide reliability problems.
- Three balloters indicated concern about the interpretation's wording related to tariffs. One of those balloters was concerned the interpretation had the potential to create confusion with or conflict with the transmission curtailment priority specified in its Open Access Transmission Tariff ("OATT"). One balloter suggested the interpretation request

appears to be using the interpretation process to inject tariff change, explaining that curtailing only certain schedules during an emergency will have no measurable effect on "CPS," which has monthly and yearly measures.

- Two balloters indicated that basing curtailments of off-system schedules on whether or not the schedule is ultimately designated as a network resource is incorrect. The balloters stated there are various types of firm sales that can qualify as a network resource, and not all will be more firm than native load.
- One balloter suggested that the issue of how to deal with identifying and coordinating network resources in the source, sink, and intermediary Balancing Authority areas should be addressed (perhaps by another standard) prior to proceeding with this interpretation.
- Two balloters indicated it would be more reasonable to curtail based on transmission type (*e.g.*, non-firm versus firm), stating it is not practical to expect the source Balancing Authority to identify which exports have been designated as network resources by another entity.
- Three balloters indicated the changes do not seem to address the comments on the first ballot.
- Three balloters believe the interpretation is in conflict with FERC's definition of firm transactions. The balloters referenced a FERC definition of firm in the FERC Form 1 (p. 310) and stated there have been numerous Commission and U.S. Circuit Court proceedings that establish curtailment rights and obligations.
- One balloter indicated the interpretation does not cover the situation in which the exporting entity is a Generator Owner but not a Load-Serving Entity, explaining there are different curtailment situations for generating capacity and transmission capacity shortages.
- One balloter indicated the interpretation does not go far enough in explaining the difference between EOP-002-2 and IRO-006-4 and suggested coordination between the interpretation drafting team and Transmission Loading Relief Standard Drafting Team to provide a more complete interpretation and avoid subsequent interpretation requests. The balloter suggest adding the wording to the interpretation to explain EOP-002-2 is related to generating capacity shortages in a control area, whereas IRO-006-4 deals with transmission system overload conditions.

The twelfth ballot event in the 3rd quarter of 2009 consisted of initial ballot for an interpretation of standard CIP-005-1 — Cyber Security — Electronic Security Perimeter(s), Section 4.2.2 and Requirement R1.3 for PacifiCorp.

PacifiCorp asked the following questions that include reference to Electronic Security Perimeter ("ESP") and Physical Security Perimeter ("PSP"):

1. (Section 4.2.2) "What kind of cyber assets are referenced in 4.2.2 as 'associated'? What else could be meant except the devices forming the communication link?"
2. (Section 4.2.2) "Is the communication link physical or logical? Where does it begin and terminate?"
3. (Requirement R1.3) "Please clarify what is meant by an 'endpoint'? Is it physical termination? Logical termination of OSI layer 2, layer 3, or above?"

4. (Requirement R1.3) "If 'endpoint' is defined as logical and refers to layer 3 and above, please clarify if the termination points of an encrypted tunnel (layer 3) must be treated as an access point? If two control centers are owned and managed by the same entity, connected via an encrypted link by properly applied Federal Information Processing Standards, with tunnel termination points that are within the control center ESPs and PSPs and do not terminate on the firewall but on a separate internal device, and the encrypted traffic already passes through a firewall access point at each ESP boundary where port/protocol restrictions are applied, must these encrypted communication tunnel termination points be treated as 'access points' in addition to the firewalls through which the encrypted traffic has already passed?"

The drafting team provided the following clarifications:

1. In the context of applicability, associated Cyber Assets refer to any communications devices external to the Electronic Security Perimeter, i.e., beyond the point at which access to the Electronic Security Perimeter is controlled. Devices controlling access into the Electronic Security Perimeter are not exempt.
2. The drafting team interprets the data communication link to be physical or logical, and its termination points depend upon the design and architecture of the communication link.
3. The drafting team interprets the endpoint to mean the device at which a physical or logical communication link terminates. The endpoint is the Electronic Security Perimeter access point if access into the Electronic Security Perimeter is controlled at the endpoint, irrespective of which Open Systems Interconnection (OSI) layer is managing the communication.
4. In the case where the "endpoint" is defined as logical and is >= layer 3, the termination points of an encrypted tunnel must be treated as an "access point." The encrypted communication tunnel termination points referred to above are "access points."

The initial ballot was conducted from August 27, 2009 through September 8, 2009 and achieved a quorum of 84.68% with a weighted affirmative approval of 80.37%. There were 45 negative ballots submitted for the initial ballot, and 30 of those ballots included a comment, which initiated the need for a recirculation ballot. Some balloters listed more than one reason for their negative ballot.

The reasons cited for the negative ballots included the following:

- Seventeen balloters indicated the interpretation either did not provide sufficient clarity or raised more questions, and these commenters provided reasons or examples of their concerns:
    - Eight balloters sought more information regarding what constitutes an "endpoint" or the communication link's termination points. One suggested the interpretation should state the termination points depend on design and architecture and could include at least three common design examples.
    - Three balloters sought more information about "data communication links."
    - One balloter asked if the communication link was meant to be physical or logical.
    - Four asked how control could be better than a six-wall border.

  - Two gave an example that in the response to question 4, there is discussion relative to layers 3 and higher, but nothing mentioned for layer 1 or 2.
- One balloter disagreed with the response to question 3 regarding logical communication links, stating it could be taken to mean that any device at which a logical connection into the ESP terminates would be considered an access point.
- Fourteen balloters indicated concerns with the answer to question 4:
  - Four balloters indicated the firewall access points already enforce port/protocol restrictions, which meet the requirement, stating that "[a]dding the further restriction of access points at the encryption endpoint is unnecessary, increases complexity which by definition reduces reliability, and can have much wider implications beyond encrypted tunnels."
  - Four balloters indicated wording in the response that "the termination points of an encrypted tunnel must be treated as an 'access point'" is too restrictive and will conflict with other interpretations, specifically PacifiCorp's request for interpretation of CIP-006-1 (discussed as the thirteenth ballot event in this report). The balloter was concerned that the interpretation could be viewed as indicating all encrypted tunnels are an access point to an ESP.
  - One balloter disagreed with the response to question 4, stating that VPN (virtual private network) traffic should be treated that same as any other logical connection and that the access point to the ESP is able to provide layer 3 and 4 protection regardless of the type of traffic being traversed.
  - One balloter indicated the question is confusing but believes the intent is to clarify that "access points" to an ESP can be effectively moved with the application of appropriate equipment. The balloter stated that a communication link between two ESPs utilizing an encrypted tunnel must have an encryption/decryption device at each end inside the ESP that would be defined as the "termination point." The balloter asked, "if an additional protective device is added before the 'termination point' to protect the ESP, would this not affectively move the 'access point?' Must the logs of both protective devices be maintained?"
  - Three balloters indicated that "A distinction has to be made in the response in regards to the encryption tunnel termination point when deciding whether such termination point is treated as an 'access point' or not."
  - One balloter indicated the response implies that use of encryption is not a suitable means of protection for access. The balloter believes an encrypted tunnel used between two ESPs would ensure restricted access.

The thirteenth ballot event in the 3rd quarter of 2009 consisted of an initial ballot of an interpretation of standard CIP-006-1 — Cyber Security — Physical Security of Critical Cyber Assets, Requirement R1.1 for PacifiCorp.

PacifiCorp requested clarification on alternative measures for physical access control:

1. If a completely enclosed border cannot be created, what does the phrase, "to control physical access" require?
2. Must the alternative measure be physical in nature? If so, must the physical barrier literally prevent physical access e.g. using concrete encased fiber, or can the alternative

measure effectively mitigate the risks associated with physical access through cameras, motions sensors, or encryption?

3. Does this requirement preclude the application of logical controls as an alternative measure in mitigating the risks of physical access to Critical Cyber Assets?

The drafting team offered the following interpretation:

For Electronic Security Perimeter wiring external to a Physical Security Perimeter, the drafting team interprets Requirement R1.1 as not limited to measures that are "physical in nature." The alternative measures may be physical or logical, on the condition that they provide security equivalent or better to a completely enclosed ("six-wall") border. Alternative physical control measures may include, but are not limited to, multiple physical access control layers within a non-public, controlled space. Alternative logical control measures may include, but are not limited to, data encryption and/or circuit monitoring to detect unauthorized access or physical tampering.

The initial ballot was conducted from August 27, 2009 through September 8, 2009 and achieved a quorum of 84.92% with a weighted affirmative approval of 79.04%. There were 34 negative ballots submitted for the initial ballot, and 20 of those ballots included a comment, which initiated the need for a recirculation ballot. Some balloters listed more than one reason for their negative ballot.

The reasons cited for the negative ballots included the following:

- Four balloters indicated they do not think wiring qualifies as a Cyber Asset subject to CIP requirements. Some balloters offered opinions of what should be considered Cyber Assets:
    - Cyber Assets are those that are IP addressable (routable) or accessible via hard lines (*i.e.* telephone or modem)
    - Cyber Assets are those components to which the wires are connected, such as patch panels, routers, switches, *etc.*
- Five balloters did not believe the interpretation fully addressed the issues raised by PacifiCorp. The balloters indicated the response only addressed the ESP wiring external to a PSP and not alternative measures to control physical access to Critical Cyber Assets that may not reside within a "six-wall" physical border.
- One balloter indicated the interpretation lacked clarity regarding the characteristics of an "endpoint" and what devices are in scope as being associated with "data communication links."
- One balloter suggested the drafting team explain the purpose of a six-wall border and measures for effectiveness, which would allow for an alternative implementation to be measured.
- Two balloters indicated the question being asked is broader than just the location of the wiring that makes up part of the ESP. One balloter requested more specifics for what constitutes appropriate alternative measures; what is meant by control; and how a logical measure could be equivalent to or better than a physical measure, stating that logical controls won't prevent the cutting of a cable.

- Three balloters indicated the response to question 3 is confusing and introduces ambiguity into the standards, stating a thorough analysis of the implications of defining endpoints as either physical or logical and the resulting impact on the rest of the standards has not been completed.

- Two balloters indicated Requirement R1.1 requires physical measures and does not reference logical measures. Though one balloter indicated support for allowing alternative protective measures, both balloters indicated this interpretation would essentially change the requirement and standard, which is inconsistent with the *Reliability Standards Development Procedure* (interpretations may not be used for this purpose).

- One balloter requested clarification regarding whether "wiring" is meant as physical wires or a broader concept of communication paths, "including intermediate devices such as repeaters, bridges, frame relay devices, MPLS nodes, etc." The balloter also requested clarification regarding which elements of security need to be provided (confidentiality, integrity, availability, *etc.*).

- One balloter from PacifiCorp, the entity that requested the interpretation, seemed to indicate support for this interpretation but voted no with a reference to another interpretation. The balloter indicated this interpretation for CIP-006-1 Requirement R1 clarifies the option to use logical controls as alternative measures, which is something the company supported. The balloter explained the posted interpretation of CIP-005-1, Section 4.2.2 and CIP-005-1, Requirement R1.3 (discussed as the twelfth ballot event in this report), which was also requested by PacifiCorp, did provide the clarity the company sought regarding the characteristics of an "endpoint" and what devices are in scope as being associated with "data communication links."

The fourteenth ballot event in the 3rd quarter of 2009 consisted of an initial ballot for proposed modifications to standards BAL-006-2 — Inadvertent Interchange and INT-003-3 — Interchange Transaction Implementation.

The revisions to the standards were made specifically to remove three Midwest Independent Transmission System Operator ("Midwest ISO") waivers from BAL-006-1 and INT-003-2. The scope of this project was limited to the removal of the three waivers listed below – there were no conforming changes to the applicability, requirements, measures, or compliance elements of the standard.

1. RTO Inadvertent Interchange Accounting Waiver from BAL-006 — Inadvertent Interchange
2. Scheduling Agent Waiver from INT-003 — Interchange Transaction Implementation
3. Enhanced Scheduling Agent Waiver from INT-003 — Interchange Transaction Implementation

The three waivers, drafted to accommodate the operation of the Midwest ISO market in a multi-Balancing Authority environment, were approved by the NERC Operating Committee prior to the development of mandatory and enforceable standards, and carried forward intact into the Version 0 standards that became mandatory and enforceable via Order No. 693. Now that the Midwest ISO is a Balancing Authority, these waivers are no longer needed by the Midwest ISO. Removing these waivers (or references to the Midwest ISO) will make the standards clearer.

The initial ballot was conducted from August 27, 2009 through September 8, 2009 and achieved a quorum of 85.28% with a weighted affirmative approval of 99.62%. There was one negative ballot submitted for the initial ballot. Since the negative vote did not include a comment, the results were final.

The fifteenth ballot event in the 3rd quarter of 2009 consisted of an initial ballot of an interpretation of standard CIP-007-1 — Cyber Security — Systems Security Management, Requirement R2 for the Western Electricity Coordinating Council (WECC).

WECC was seeking clarification regarding whether the term "port," as used in Requirement R2, means a physical (hardware) or a logical (software) connection to a computer. The drafting team interpreted the term "ports" used as part of the phrase "ports and services" to refer to logical ports, *e.g.*, Transmission Control Protocol ("TCP") ports, where interface with communication services occurs.

The initial ballot was conducted from September 9, 2009 through September 21, 20009 and achieved a quorum of 85.31% with a weighted affirmative approval of 100%. Since there was no negative ballot that included a comment, these results are final.

The sixteenth ballot event in the 3rd quarter of 2009 consisted of an initial ballot of proposed VSLs for CIP standards CIP-002-2 through CIP-009-2 and VRFs for CIP-003-2 and CIP-006-2.

Standards CIP-002-2 through CIP-009-2 were approved by stakeholders and the NERC Board, and filed for Commission approval. The purpose of this part of the project was to complete the VSLs (for CIP-002-2 through CIP-009-2) and VRFs (for CIP-003-2 and CIP-006-2) for those standards. This step is part of the overall Project 2008-06 — Cyber Security Order 706.

- The VSLs are those associated with requirements that were modified when converting standards CIP-002-1 through CIP-009-1 into CIP-002-2 through CIP-009-2.

- The VRFs are for the two standards with VRF changes resulting from modifications made during the transition from standards CIP-002-1 through CIP-009-1 to CIP-002-2 through CIP-009-2:
  - CIP-003-2 — Security Management Controls
  - CIP-006-2 — Physical Security of Critical Cyber Assets.

The initial ballot was conducted from September 10, 2009 through September 21, 2009 and achieved a quorum of 87.45% with a weighted affirmative approval of 94.18%. There were 11 negative ballots submitted for the initial ballot, and 4 of those ballots included a comment, which initiated the need for a recirculation ballot. Some balloters listed more than one reason for their negative ballot.

The reasons cited for the negative ballots included the following:

- One balloter indicated the lack of a signed and dated record of the senior manager or delegate(s) annual approval of the list of Critical Assets and Critical Cyber Assets on an annual basis should not be considered a severe VSL. The balloter stated this is a case where the requirements and exposure to penalties focus on documentation with little to no impact on regional reliability or reducing the risks of wide-spread cascading outages.

- One balloter indicated the assignment of a severe VSL for Requirement R3 of CIP-006-2 for a single Cyber Asset not residing within an identified Physical Security Perimeter is arbitrarily harsh and does not seem to match the violation.
- One balloter indicated the assignment of a severe VSL for Requirement R3 of CIP-003-2 for what appears to be failure to complete any one of the following requirements through the use of the "or" is inconsistent with other VSL assignments: "A senior manager's delegate is not identified by name, title, and date of designation; the document delegating the authority does not identify the authority being delegated; the document delegating the authority is not approved by the senior manager; or changes to the delegated authority are not documented within thirty calendar days of the effective date." The balloter stated other VSL assignments seem to be characterized severe for failure to complete all the requirements.
- One balloter indicated that the VSL for Requirement R3 of CIP-003-2 provides no allowance for a situation where no exceptions exist; the balloter suggested the following wording: "The senior manager or delegate(s) did not authorize and document as required, one or more exceptions from the requirements of the cyber security policy as required that were invoked or implemented."
- One balloter indicated the posting lacked clarity regarding scope and reasoning for the changes and stated the drafting team should provide an overview of its work product and approach.

The seventeenth ballot event in the 3rd quarter of 2009 consisted of an initial ballot for proposed standard EOP-008-1 — Loss of Control Center Functionality.

The purpose of the standard is to ensure continued reliable operations of the Bulk Electric System in the event that a control center becomes inoperable. The standard has been modified significantly from the "Version 0" standard to add more specificity to the requirements and to address issues raised by FERC in Order 693. The standard incorporates a number of changes based on input received from the industry during the drafting and comment process.

The initial ballot was conducted from September 16, 2009 through September 28, 2009 and achieved a quorum of 82.69% with a weighted affirmative approval of 72.86%. There were 62 negative ballots submitted for the initial ballot, and 48 of those ballots included a comment, which initiated the need for a recirculation ballot. Some balloters listed more than one reason for their negative ballot.

The reasons cited for the negative ballots included the following:

- One balloter indicated Requirements R3 and R4 should be modified to clarify that a backup facility does not have to be continuously staffed by applicable certified operators, and that applicable functional entities are allowed a two-hour transition period to fully implement the backup functionality, as specified in Requirement R1, Part 1.5.
- Twenty balloters indicated concerns about Requirement R6 regarding the phrase: "…shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards." Most balloters requested clarification about what "can independently maintain" means. The main concern was the potential for varying interpretations of this phrase, especially from

auditors. The balloters requested clarifications regarding what is needed to satisfy the requirement, such as whether it includes all communications equipment.

- Two balloters indicated that Requirement R1, Part 1.4 should be an Operating Process as opposed to an Operating Procedure based on the definitions in the NERC *Glossary of Terms used in Reliability Standards*.
- Six balloters indicated that for Requirement R4, "two weeks or less" should be changed to "four weeks or less" because two weeks may be too short for the type of remodels that might be required of control center facilities or systems and because there seems to be little risk with extending to four weeks.
- Four balloters indicated that Requirement R4 and Measure M4 should be reworded to clarify that a backup control facility does not require 24x7 staffing unless contracting for backup services or performing as the primary control center.
- Three balloters indicated the phrase "sufficient for maintaining compliance with all Reliability Standards" is subjective and should be removed from Requirement R4 and Measure M4.
- One balloter indicated Requirement R4 is written in a manner that could lead one to believe the backup center would be dependent on primary control center functionality for "maintaining compliance with all Reliability Standards."
- Five balloters indicated Requirement R1, Part 1.2.5 is redundant with CIP standards, mentioning CIP-002-1 Requirement R1, Part1.2.1 specifically. Three balloters stated physical and cyber security are not needed to support backup functionality.
- Two balloters indicated "the old R3" should be removed.
- Five balloters indicated the phrase "prolonged period of time" in Requirement R1, Part 1.1 is unnecessary and misleading, stating that backup functionality should be required for as long as the primary control center is not available.
- Three balloters indicated the requirement of a two-hour timeframe for an entity to fully implement the backup functionality in Requirement R1, Part 1.5 may not be enough time for entities that may be impacted by events such as natural disasters. One balloter suggested the standard should allow an alternative plan (manual dispatch), and have the backup operating within a reasonable time after the alternative plan is operating.
- Seven balloters indicated concerns with Requirement R1 Part 1.2.1, dealing with tools and applications that allow visualization capabilities for operating personnel situational awareness.
    - Four balloters indicated the requirement needs clarification, asking if the same functionality is required at the backup control center that is available at the primary control center, *e.g.*, a video wall.
    - Three balloters indicated the requirement should be removed because situational awareness is not a measurable state of a control room facility.
- Four balloters had concerns with Requirement R5, Part 5.1, regarding update and approval of the Operating Plan for backup functionality for any changes in capabilities. One balloter indicated the word "any" is too broad, and three balloters indicated the requirement should be removed because it is an unnecessary administrative burden,

highly subjective regarding a change in capabilities, and already addressed in Requirement R5.

- Three balloters indicated the latter part of Requirement R1, Part 1.6.2, dealing with backup functionality, is a departure from Requirement R1., Part 1.6, and planned and unplanned outages are addressed in Requirement R3 for Reliability Coordinators and Requirement R4 for Balancing Authorities and Transmission Operators.
- Three balloters indicated some of the clarifications provided by the standards drafting team in its responses to industry questions/comments were not added to the standard, such as for "prolonged period of time" and "annual test." The balloter suggested either adding the clarifications to the standard or including them in a FAQ document to prevent the possibility of inconsistent adherence to the standard and interpretation during audits.
- One balloter indicated the standard should not mandate how an entity ensures that backup functionality exists.
- Three balloters indicated it should be clear that under normal operations only primary and adequate backup facilities/functionalities are required for compliance.
- One balloter indicated interpretation issues exist for compliance expectations concerning CIP standards when the language in Requirement R4 states "maintaining compliance with all Reliability Standards."
- One balloter indicated Requirement R1, Part 1.2 should be removed because Requirement R1.3 requires "An Operating Process for keeping the backup functionality consistent with the primary control center" and all items listed in Requirement R1, Part 1.2 except Requirement R1, Part 1.2.4 are already required for the primary control center in other NERC standards.
- One balloter indicated seeing no reliability value in being required to approve its Operating Plan after completing the annual review, as required in Requirement R5.
- One balloter indicated the revised language was supposed to eliminate the need for a tertiary backup facility but may actually create an unintentional requirement for a tertiary facility if a planned outage of the primary or secondary facility exceeds two weeks.
- One balloter indicated being troubled by drafting team removing Requirement R3 due to consultation with NERC staff that indicated the requirements were already addressed through compliance administration processes.

CERTIFICATE OF SERVICE

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

Dated at Washington, D.C. this 2nd day of November 2009.

/s/ *Holly A. Hawkins*

Holly A. Hawkins

Attorney for North American Electric Reliability Corporation